2011-2012 TRANSMISSION PLAN

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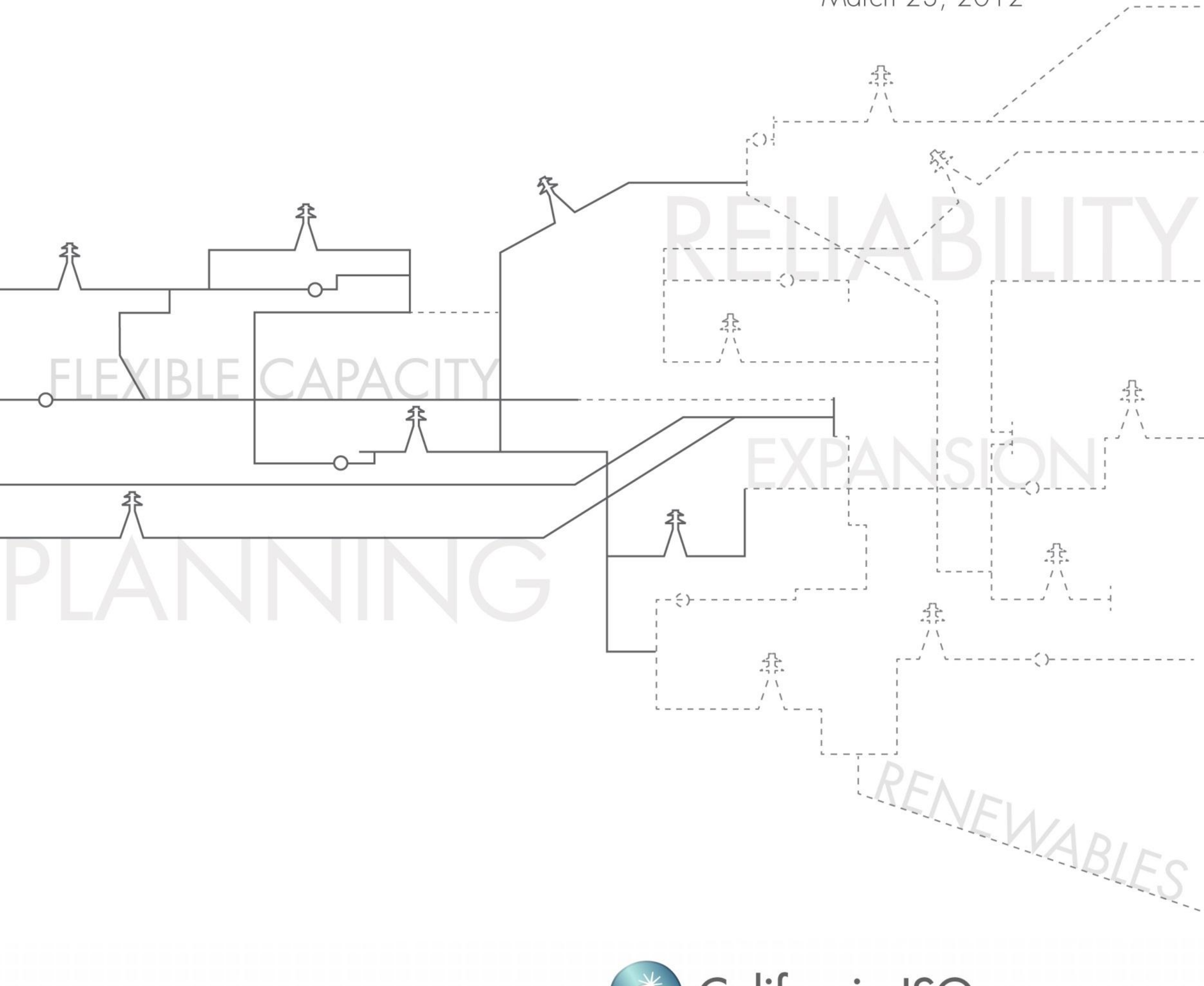

California ISO
Shaping a Renewed Future

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Approved by ISO Board of Governors

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Executive Summary

Introduction

The 2011/2012 California Independent System Operator Corporation transmission plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to successfully meet California's policy goals. It also examines conventional grid reliability requirements and projects that can bring economic benefits to consumers. This plan is updated annually. In recent years, California enacted policy goals aimed at reducing greenhouse gases and increasing renewable resource development. The state's goal, to have renewable resources provide 33 percent of California's retail electricity consumption by 2020, has become the principal driver of substantial investment in new renewable generation capacity both inside and outside of California.

The transmission plan describes the transmission necessary to meet the state's 33 percent Renewable Portfolio Standard (RPS) goals. Key analytic components of the plan include:

- Identification of transmission needed to support meeting the 33 percent RPS over a diverse range of renewable generation portfolio scenarios, which are based on plausible forecasts of the type and location of renewable resources in energy-rich areas most likely to be developed over the 10 year planning horizon;
- A "least regrets[1]" analysis of transmission infrastructure under development but not yet permitted, as well as policy-driven elements that might be needed to deliver energy from the resources in these portfolios to the ISO grid;
- Identification of transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements; and
- Economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits.

Our comprehensive evaluation of the areas listed above resulted in the several findings. One such finding is that, consistent with the 2010/2011 transmission plan, no new major transmission projects are required to be approved by the ISO at this time to support achieving of California's 33 percent RPS goals given the transmission projects already approved or progressing through the California Public Utilities Commission (CPUC) approval process. This is because of the following:

- The major transmission projects already underway accommodate a diverse range of resource portfolios for meeting the 33 percent RPS, including in-state generation, distributed generation, and out of state scenarios;

[1] The "least regrets" approach can be summarized as evaluating a range of plausible scenarios made up of different generation portfolios, and identifying the transmission reinforcements found to be necessary in a reasonable number of those scenarios. It is captured in more detail in the ISO tariff, in section 24.4.6.6.

- Existing inter-state transmission will have capacity made available as renewable resources displace energy from traditional resources;
- Approving more transmission under the circumstances and conditions that exist today would increase risk of stranded costs;

The ISO will reassess transmission needs in future annual planning cycles and consider any changed conditions, potential policy changes (e.g., increased emphasis on distributed generation), renewable generation advances utilizing previously approved transmission, and any new factors that may drive future generation development.

Justification for additional transmission to support out-of-state procurement will need to be addressed in subsequent transmission plans through the CPUC renewable energy procurement approval process to determine the specific location, quantity, and type of renewable energy projects.

Immediate focus now should be on:

- obtaining approvals for identified transmission;
- renewable energy procurement; and;
- revisiting procurement forecasting assumptions for use in the 2012/2013 transmission plan cycle.

Other key findings from the report include the following:

- The ISO identified 30 transmission projects with an estimated cost of $691 million, as needed to maintain the reliability of the ISO transmission system.
- The ISO performed a transmission congestion study to determine potential areas for transmission reinforcement, and performed six economic studies as requested by stakeholders. The analyses compared the cost of the mitigation plans to the expected reduction in production costs, congestion costs, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources and determined that none of the mitigation plans were economically justified at this time. Three projects have been identified as having potential benefits, and will receive further evaluation in the future.
- The ISO's tariff sets out a competitive solicitation process for policy-driven category 1 and economically-driven elements found to be needed in the plan, as well as elements of reliability projects that provide additional policy or economic benefits. The ISO has not identified new policy-driven or economically-driven elements in this plan. The ISO further reviewed the reliability-driven projects for potential candidates for competitive solicitation process, and evaluated the policy benefits and economic benefits for five potential candidates. That analysis indicated that none of those elements met the Commission-approved criteria for advancement into the competitive procurement process.

The finding that no major new transmission projects are needed at this time to support the California's RPS reflects years of effort by California state agencies, participants in the Renewable Energy Transmission Initiative (RETI), market participants and the ISO that resulted in the approval and ongoing construction of major transmission projects such as Tehachapi and the Sunrise Powerlink. The ISO recognizes, however, that uncertainty remains regarding how California will ultimately meet its 33 percent RPS in terms of the precise locations, resource mix and quantity of renewable energy resources. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly. The ISO, the CPUC and the California Energy Commission (CEC) are already working together to incorporate the environmental data developed in the course of the Desert Renewable Energy Conservation Plan into renewable generation portfolios to be studied in the 2012/2013 planning cycle.

This year's transmission plan is based on the ISO's transmission planning process, which involved collaborating with the CPUC, California Transmission Planning Group (CTPG) and many other interested stakeholders. Summaries of the transmission planning process and some of the key collaborative activities are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

The Transmission Planning Process

A core responsibility of the ISO is to plan and approve additions and upgrades to transmission infrastructure so that as conditions and requirements evolve over time, it can continue to provide a well-functioning wholesale power market through reliable, safe and efficient electric transmission service. Since it began operation in 1998, the ISO has fulfilled this responsibility through its annual transmission planning process. The state of California's adoption of new environmental policies and goals created a need for some important changes to the planning process. In 2009, the ISO initiated a stakeholder process to design the needed changes, and in June 2010 filed tariff amendments with the Federal Energy Regulatory Commission (FERC) to implement them. The FERC approved those tariff amendments on December 16, 2010, and the amendments went into effect on December 20, 2010.

The tariff changes provided significant enhancements to the ISO's transmission planning process, including the introduction of a policy-driven criterion for new transmission and a conceptual state-wide transmission plan to better inform transmission planning decisions. The ISO released a revised 2010/2011 conceptual statewide transmission plan update on August 31, 2011, for application in the 2011/2012 transmission planning cycle. This revision updated the February 1 version of the conceptual statewide plan, which was considered in the development of the 2010/2011 transmission plan.

Among other provisions, the tariff amendments also included a competitive solicitation process for policy-driven Category 1 and economically-driven elements, in which both non-incumbent transmission developers and participating transmission owners (PTOs) may participate. FERC provided further direction to the ISO in its October 20, 2011 order regarding the ISO's tariff compliance filing, directing the ISO to expand the category of elements eligible for competitive solicitation to include reliability projects that provide additional policy or economic benefits. The ISO filed its second compliance filing on December 2, 2011, and is awaiting FERC's decision on that filing.

The ISO also has an ongoing initiative to better integrate the transmission planning process with the generation interconnection procedures. A primary objective of this initiative is to better consolidate the two processes, so that decisions to build significant ratepayer-funded transmission upgrades are made holistically and in conjunction with other transmission needs in the context of the comprehensive transmission planning process. A second equally important objective is using the transmission planning process to determine which interconnection-driven facilities will be paid for by ratepayers and which will be funded by generation developers. The ISO intends to finalize its proposal for this initiative and present it to the ISO Board for approval in the first quarter of 2012, and, subject to FERC approval, implement the changes in the 2012/2013 transmission planning cycle.

Collaborative Planning Efforts

The ISO, utilities, state agencies and other stakeholders continue to work closely to assess how to meet the environmental goals established by state policy. The collaboration with these entities is evident in the following initiatives.

Renewable Energy Transmission Initiative (RETI)

A joint initiative between the ISO, CPUC, CEC, investor-owned and publicly owned utilities and other stakeholders, RETI identified areas in California and neighboring states with concentrations of high-quality renewable resources that could be delivered to California loads. Much of the data used by the CPUC in developing its generation development scenarios was initially developed through RETI.

CPUC Long Term Procurement Process (LTPP)

A memorandum of understanding (MOU) was signed by the CPUC and ISO in May 2010 to formalize coordination between the ISO's transmission planning process and the CPUC's siting and permitting processes and long-term procurement process (LTPP). The MOU calls for the ISO to consider and incorporate the generation scenarios from the LTPP process into its planning process. The CPUC, in turn, will give substantial weight in its siting and permitting process to projects that are consistent with the ISO transmission plan.

As discussed in more detail below, the CPUC in collaboration with the ISO produced the four generation scenarios studied in the 2011/2012 transmission planning cycle.

Once Through Cooling at Coastal Generation and South Coast Air Basin

On May 4, 2010, the State Water Resources Control Board (SWRCB) adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. Approximately 30 percent of California's in-state generating capacity (gas and nuclear power) uses coastal and estuarine water for once-through cooling (OTC). This policy will impact coastal generation that does not yet comply, by causing that generation to be retrofitted, repowered, or retired. During the 2011/2012 transmission planning cycle, the ISO worked with the CPUC, CEC, SWRCB, the California Air Resources Board (CARB) and interested stakeholders to obtain inputs for a comprehensive long-term reliability assessment (i.e., 2021 time frame) to determine the minimum amount of OTC generation needed for local capacity requirement (LCR) grid areas. Those study results are also summarized in this plan.

The transmission plan also summarizes the results of studies performed to assess local reliability capacity requirements in the South Coast Air Basin. This work was undertaken to meet the requirements of Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009). AB 1318 requires the CARB, in consultation with the ISO, CEC, CPUC and the SWRCB to prepare a report for the governor and legislature that evaluates the electrical system reliability needs of the South Coast Air Basin (SCAB) and recommends the most effective and efficient means of meeting those needs while ensuring compliance with state and federal law. The ISO had previously worked with various state agencies to develop the study scope for the reliability assessment of the ISO balancing authority area's Los Angeles Basin, and the studies themselves were conducted in the course of the 2011/2012 planning cycle.

California Transmission Planning Group (CTPG)

The CTPG was formed in the fall of 2009 to conduct joint transmission planning by transmission owners (investor owned utilities and publicly owned utilities) and the ISO. During the 2010/2011 planning cycle the California ISO worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33 percent RPS targets by 2020. During their individual 2010 planning cycles, CTPG members completed a significant amount of technical analyses to develop a framework for preparing a statewide transmission plan. CTPG evaluated alternative renewable resource portfolios based on participant interest, which reflected input from RETI, other stakeholders, and state agencies. Their intent was to develop a conceptual least regrets transmission plan that CTPG members who are the planning entities for their balancing authority areas would assess in greater detail as part of their own respective planning processes. The CTPG statewide transmission plan was completed in early January 2011 and presented a list of high potential and medium potential transmission elements that were identified for further consideration by all CTPG members in their development of their own 2020 RPS planning goals. The ISO performed its own independent analysis and found that the high potential transmission elements identified by CTPG were found to be needed in the ISO's 33 percent RPS transmission plan. The ISO's 2010/2011 conceptual statewide plan was initially released in January, 2011, for use in the 2010/2011 transmission planning cycle. After seeking updates from CTPG members, the ISO released a revised 2010/2011 conceptual statewide transmission plan update on August 31, 2011, for application in the 2011/2012 transmission planning cycle. The ISO notes that the current activities of the CTPG will produce a new CTPG plan in early 2012, which will be relied upon by the ISO in the development of a 2012 conceptual statewide plan for consideration in the 2012/2013 planning cycle.

33% RPS Generation Portfolios and Transmission Assessment

The transition to greater reliance on renewable generation creates significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. As a result, development in these areas often requires new transmission lines. The ISO is keenly aware that without transmission in place, developers are extremely reluctant to invest in generation. At the same time, an entirely reactive transmission planning process creates its own problems — most significantly, the time required to develop generation is typically much shorter than the time required to develop a new transmission line. In other words, a transmission process that relies on generators making investments first can leave generation without the necessary transmission for a significant period of time.

The ISO's transmission planning process addresses this challenge and uncertainty by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's 2020 RPS goals. Commonly known as a least regrets methodology, the portfolio approach allows the ISO to consider resource areas (both in-state and out-of-state) where generation build-out is most likely to occur; evaluate the need for transmission to deliver energy to the grid from these areas; and identify any additional transmission upgrades that are needed under one or more portfolios. The ISO 33 percent RPS assessment is described in detail in chapter 4 of this plan.

In consultation with interested parties, CPUC staff developed four renewable generation scenarios for meeting the 33 percent RPS goal in 2020. These scenarios vary by technology, location, and other characteristics and were developed by considering transmission constraints, cost, commercial interest, environmental concerns, and timing of development. The CPUC proposed that one of these, an updated version of the 2010 LTPP's cost-constrained scenario, be considered as a base case for ISO planning purposes. The other three scenarios - the trajectory scenario, the environmentally-constrained scenario, and the time-constrained scenario – should also be studied. In consultation with the CPUC, the ISO further modified the updated cost-constrained scenario based on stakeholder feedback to place further emphasis on potential development in West Mohave. The ISO portfolios cover a broad range of plausible generation possibilities. The generation resources comprising these four portfolios reflect the latest and best available information on the commercial interests of transmission customers, as measured by interconnection queue positions and whether the resources have signed power purchase agreements with California load-serving entities. Other factors such as cost, procurement policies, permitting, environmental assessments conducted by RETI, and resource financing capabilities were part of the metrics used to evaluate each portfolio.

In addition to the transmission already approved by the ISO through the transmission planning process (TPP), the ISO considered Large Generator Interconnection Procedures (LGIP) network upgrades required to serve renewable resources that either have or were expected to have signed generator interconnection agreements. As such, these transmission upgrades and additions form a core part of the ISO analysis methodology.

The ISO assessment of the transmission projects identified above indicate that those projects with some additional minor system upgrades are sufficient to meet the 33 percent RPS target by 2020. These transmission upgrades were tested under the four ISO generation portfolios and all of the projects identified in Table 1 below were determined to be needed and adequate for supporting energy delivery to load centers. Consequently, the ISO has concluded that no additional upgrades are needed to be approved at this time to deliver renewable resources.

The ISO also identified other upgrades that are potentially needed but require further analysis in the next transmission planning cycle as more information becomes available regarding renewable generation development and integration requirements. For example, environmental concerns are growing over the level of development occurring in the California desert. However, none of the projects evaluated in this transmission planning cycle qualified as Category 2 projects.

Table 1 provides a summary of the various transmission elements of the 2011/12 transmission plan for supporting California's RPS. These elements are composed of the following categories:

- Major transmission projects that have been previously approved by the ISO and are fully permitted by the CPUC for construction;
- Additional transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the approval process; and
- Major transmission projects that have been previously approved by the ISO but are not yet permitted.

Table 1: Elements of the 2011/2012 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Online
Transmission Facilities Approved and Permitted For Construction	
Sunrise Powerlink	2012
Tehachapi Transmission Project	2015
Colorado River - Valley 500 kV line	2013
Eldorado – Ivanpah 230 kV line	2013
Carrizo Midway Reconductoring	2012
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2015
South of Contra Costa Reconductoring	2014
Pisgah - Lugo	2017
West of Devers Reconductoring	2018
Coolwater - Lugo 230 kV line	2018
Policy-Driven Transmission Elements Approved but not Permitted	
Mirage-Devers 230 kV reconductoring (Path 42)	2014

Reliability Assessment

The reliability studies necessary to ensure compliance with North American Electric Reliability Corporation (NERC) and ISO planning standards are a foundational element of the transmission plan. During the 2011/2012 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage bandwidth of 60 kV to 500 kV, and where reliability concerns were identified, the ISO identified mitigation plans to address any concerns. These mitigation plans include upgrades to the transmission infrastructure, implementation of new operating procedures and installation of automatic special protection schemes. All ISO analysis, results and mitigation plans are documented in the transmission plan.

It is the ISO responsibility to conduct its transmission planning process in a manner that ensures planning is appropriately coordinated across its controlled grid as well as its connections with neighboring systems. The analysis that is required to prepare this transmission plan is complex and entails processing a significant amount of data and information. In total, this plan proposes approval of 30 reliability driven transmission projects, representing an investment of approximately $691 million in infrastructure additions to the ISO controlled grid. The majority of these projects (26) cost less than $50 million and has a combined cost of $411 million. The remaining three projects with costs greater than $50 million have a combined cost of $280 million and consist of the following:

***New Bridgeville-Garberville No. 2 115 kV Line Project* –** A new 115 kV line in the PG&E system from Bridgeville to Garberville, to alleviate future potential overloading of the existing Bridgeville – Garberville 60 kV line and voltage issues under several single-contingency outage conditions.

***Embarcadero-Potrero 230 kV Underground Cable Project* –** A new 230 kV XLPE underground cable from the Potrero substation to the downtown San Francisco Embarcadero substation, providing a third line of supply to the critical downtown San Francisco load center. This circuit will provide redundancy to protect against the simultaneous loss of both existing Martin-Embarcadero 230 kV circuits.

***Kern PP 115 kV Area Reinforcement Project* -** A reinforcement and upgrade project of the 115 kV system within the Kern area of the PG&E system to address a number of potential overload conditions.

The ISO notes that only one of these projects, the Embarcadero-Potrero 230 kV underground transmission reinforcement, involves new transmission construction at voltages greater than 200 kV. These reliability projects are necessary to ensure compliance with the NERC and ISO planning standards. A summary of the number of projects and associated total costs in each of the four major transmission owners' service territories is listed below in Table 2. Because PG&E and SDG&E have lower voltage transmission facilities (i.e., 138 kV and below) under ISO operational control, a higher number of projects were identified mitigating reliability concerns in those utilities' areas, compared to the lower number for SCE.

In arriving at these projects, the ISO and transmission owners performed power system studies to measure system performance against the NERC reliability standards and ISO planning standards as well as to identify reliability concerns that included among other things, facility overloads and voltage excursions. Mitigation measures were then evaluated and cost-effective solutions were recommended by ISO staff to management and the Board of Governors for approval.

Table 2 – Summary of Approved Reliability Driven Transmission Projects in the ISO 2011/2012 Transmission Plan

Service Territory	Number of Projects	Cost
Pacific Gas & Electric (PG&E)	22	$610 M
Southern California Edison Co. (SCE)	3	$25 M
San Diego Gas & Electric Co. (SDG&E)	5	$56 M
Total	30	$691 M

The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in Table 2 include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.

Economic Studies

Economic studies of transmission needs are another fundamental element of the ISO transmission plan. The objective of these studies is to identify transmission congestion and analyze if the congestion can be cost effectively mitigated by network upgrades. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. Resolving congestion bottlenecks is cost effective when ratepayer savings are greater than the cost of the project. In such cases, the transmission upgrade can be justified as an economic project.

The ISO economic planning study was performed after evaluating all policy-driven transmission (i.e., meeting RPS targets) and reliability-driven transmission. Network upgrades determined by reliability and renewable studies were modeled as an input in the economic planning database to ensure that the economic driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs. The engineering analysis behind the economic planning study was performed using a production simulation and traditional power flow software.

Grid congestion was identified using production simulation and congestion mitigation plans were evaluated through a cost-benefit analysis. Economic studies were performed in two steps: 1) congestion identification; and 2) congestion mitigation. In the congestion identification phase, grid congestion was simulated for 2016 (the 5th planning year) and 2021 (the 10th planning year). Congestion issues were identified and ranked by severity in terms of congestion hours and congestion costs. Based on these results, the five worst congestion issues were identified and ultimately selected as high-priority studies.

In the congestion mitigation phase, congestion mitigation plans were analyzed for the five worst congestion issues. In addition, six economic study requests were submitted in the 2010 request window, and were evaluated in the 2011/2012 planning cycle. Based on the costs-benefits analyses performed by the ISO for all of the proposed congestion mitigation proposals, the ISO has concluded that none of the studied projects warrant approval in the 2011/2012 planning cycle. As part of the 2012/2013 transmission planning cycle a comprehensive study plan will be developed for the Central California area.

Therefore, the ISO is not recommending any economic upgrades as part of the 2011/2012 planning cycle.

Once Through Cooling and South Coast Air Basin (AB 1318)

The ISO's analysis of future requirements for generation currently relying on once-through cooling technology focused on the needs in local capacity areas, and then assessed the needs for the broader zonal area, referred to as the South of Path 26 (SP 26) area. Path 26 refers to the three 500 kV transmission lines from Midway to Vincent. After those results were determined, transient stability assessments were performed to ensure that the minimum requirements in the local areas and the broader SP 26 area were sufficient to maintain transient stability under critical contingencies.

The local area capacity requirements for generation currently relying on once-through cooling use of coastal water are provided in Table 3.

Table 3 – Summary of long-term (2021) LCR study results

LCR Area	Local Capacity Requirements (MW)				OTC Generation Need? If Yes, Range of OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
Greater Bay Area	5,773	4,728	5,778	6,572	No			
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	Yes (for Moorpark, a sub-area of the Big Creek/Ventura LCR area)			
					430	430	430	430
LA Basin	13,300	12,567	12,930	13,364	Yes (for Western LA Basin and Ellis sub-areas)			
Western LA Basin (Sub-Area of the LA Basin LCR Area)	7,797	7,564	7,517	7,397	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
San Diego / Imperial Valley	3,291	3,104	2,968	3,272	Yes (*Lower values correspond to OTC generation need when including SDG&E-proposed generation for LTPP)			
San Diego	2,883	2,859	2,900	2,856	531* - 950	231*-650	231*-650	421*-840

In evaluating the needs of the SP 26 area, the four RPS portfolios were again evaluated assuming that OTC generation that was not required in the local capacity area analysis would be retired. Both one-in-two and one-in-ten heat wave load conditions were studied. Based on the results summarized in Chapter 3, Tables 3.3-4 to 3.3-7, the following potential resource deficiency concerns for SP26 were identified for two RPS portfolios:

- Trajectory portfolio: for SP26, potential resource deficiencies of 1,875 MW were identified for 1-in-10 year heat wave load projection for 2021;
- Time constrained portfolio: for SP26, potential resource deficiencies of 3,919 MW were identified for 1-in-10 year heat wave load projection for 2021.

The transient stability analysis did not identify further requirements at this time.

The analysis of the South Coast Air Basin generation requirements, which includes the LA Basin local capacity area, was based largely on the analyses performed for the purposes of developing this transmission plan and assessing the requirements for OTC generation. The four study objectives of the AB 1318 reliability studies can be summarized as:

1. A reliability assessment of the LA Basin local capacity area requirements for the four RPS portfolios at peak load conditions;
2. An assessment for conditions with incremental uncommitted energy efficiency and demand response for the environmentally constrained study case as a sensitivity study;
3. A transient stability assessment for on-peak and off-peak load conditions; and
4. A load and resource assessment for the zonal areas (NP 26 and SP 26) as well as the overall ISO balancing authority area.

As all but the second requirement were addressed in the OTC study work, only the second requirement required additional analysis. The ISO therefore performed additional analysis to determine the lower amounts of local capacity requirements in the environmentally-constrained case with incremental uncommitted energy efficiency and demand response. The results of that analysis are provided below in Table 4. The results indicated that, if incremental energy efficiency and demand response were to fully materialize as assumed, the resulting LA Basin generation need would be about 10,761 MW versus a 13,364 MW need under high-net load condition for the same RPS portfolio (environmentally constrained). Additionally, under this scenario the OTC capacity replacement need for the Western LA area is 802-1,275 MW, compared to 1,870-2,884 MW under the high net load condition (Table 3).

Table 4 – Summary of sensitivity assessment with incremental uncommitted energy efficiency and demand response for the CPUC environmentally constrained portfolio

Area	Local Capacity Requirements (MW)	Existing OTC Units Needed?
LA Basin Overall	10,761	Yes
Western LA	6,458	802 - 1,275

Conclusions and Recommendations

The 2011/2012 ISO transmission plan, which is updated annually, provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, in addition to examining conventional grid reliability requirements as well as projects that can bring economic benefits to consumers. This year's plan identified 30 transmission projects, estimated to cost a total of approximately $691 million, as needed to maintain the reliability of the ISO transmission system. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly.

SECTION I: INTRODUCTION

Chapter 1

Overview of the Transmission Planning Process and the 2011/2012 Transmission Planning Cycle

1.1 Purpose

One of the core responsibilities of the ISO is to identify and plan the development of additions and upgrades to the transmission infrastructure that comprises the ISO controlled grid. The ISO fulfills this responsibility by conducting an annual transmission planning process, which culminates in a board-approved, comprehensive transmission plan. The plan identifies needed additions and upgrades and authorizes cost recovery, subject to FERC approval, through ISO transmission rates. This document serves as the comprehensive transmission plan for the 2011/2012 planning cycle.

The plan categories justification for transmission projects based upon three main reasons: reliability, public policy or economic. The transmission plan may also include projects that maintain the feasibility of long-term congestion revenue rights, give renewable resources access or provide for and provide for merchant transmission projects.

Reliability projects are identified pursuant to the ISO responsibility to ensure that transmission system performance is compliant with all North American Electric Reliability Corporation standards as well as the ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2011/2012 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to verify compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon, and it modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage range of 60 kV to 500 kV. When reliability concerns were observed, the ISO identified mitigation plans to address these concerns that include included upgrading transmission infrastructure, implementing new operating procedures and installing automatic special protection schemes. ISO analyses, results and mitigation plans are documented in this transmission plan.

Public policy-driven transmission additions and upgrades needed to enable the grid infrastructure to support mandates and requirements established in state or federal policy. The best example of such a mandate is California's state law requiring that 33 percent of the electricity consumed in the state on an annual basis be supplied from qualified renewable resources by the year 2020. Achieving this mandate will require the development of substantial amounts of new renewable generating resources, along with the construction of new grid infrastructure to deliver their electricity output to consumers. The public policy-driven category was added to the ISO transmission planning process in 2011 in recognition that the new transmission needed to support policies such as environmental goals would unlikely qualify for approval based on the criteria defining the other categories of transmission.

Economically-driven additions and upgrades are those that offer economic benefits to consumers that exceed their costs based on a variety of ISO studies, including a production simulation. Typical economic benefits are reductions in congestion costs, reductions in line losses and access to lower cost resources for the supply of energy and capacity.

1.2 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases. Because these phases extend for more than a single calendar year, each planning cycle is identified by a beginning year and a concluding year. For example, the 2011/2012 planning cycle begins in January 2011 and concludes at the earliest in March 2012 and possibly later.

Phase 1 includes establishing the assumptions and models that will be used in the planning studies; developing and finalizing a study plan; and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the first year of the cycle.

Phase 2 includes the various studies the ISO performs for the purpose of identifying specific needed transmission additions and upgrades and culminates in the annual comprehensive transmission plan. This phase takes approximately 12 months from when the planners begin to perform the studies until the comprehensive plan is presented to the ISO Board for approval. Thus the time from the start of a planning cycle to the presentation of a comprehensive plan to the ISO Board – phases 1 and 2 of the cycle – is 15 months.

Phase 3 includes the competitive solicitation by the ISO for prospective developers to build and own transmission elements in the economically and policy-driven categories of the Board-approved plan. In any given planning cycle, phase 3 may or may not be needed depending on whether the final plan includes transmission elements that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

1.2.1 Phase 1

Phase 1 generally consists of two parallel activities: development and completion of the annual unified planning assumptions and study plan, and developing a conceptual statewide transmission plan, which may be completed during phase 1 or phase 2. The formulation of a set of generating resource portfolios that reflect alternative potential scenarios of development of new generation to meet state or federal public policy mandates is part of the unified planning assumptions, but in the case of the current 2011/2012 planning cycle, formulating resource portfolios occurred in the first few months of phase 2 on a third parallel activity instead of in phase 1. Starting with the 2012-2013 cycle the ISO intends to perform all three activities in phase 1.

The purpose of the unified planning assumptions is to establish a common set of assumptions for the reliability and other planning studies the ISO will perform in phase 2. The starting point for the assumptions is information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures (GIP) and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions the ISO also specifies the public policy requirements and directives that will affect the need for new transmission infrastructure.

Public policy requirements and directives are a new element of transmission planning that the ISO added to its planning process in 2010. This element will be a national requirement under FERC's Order No. 1000. It enables the ISO to identify and approve transmission additions and upgrades that will be needed to enable the users of the ISO system to comply with state and federal mandates. The relevant policy directive for last year's planning cycle and the current cycle is California's RPS that calls for 33 percent of the electricity consumed in the state in 2020 be provided from renewable resources. This requirement is driving substantial development of new renewable generating resources, which will require new transmission infrastructure to deliver their energy to consumers.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment, during which stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then specifies a list of high priority studies among these requests (i.e., those which the engineers expect may provide the greatest benefits) and includes them in the study plan when it publishes the final unified planning assumptions and study plan at the end of phase 1. The list of high priority studies may be modified later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

The conceptual statewide transmission plan, also added to the planning process in 2010, was initiated based on the recognition that policy mandates such as the RPS will typically apply throughout the state, not only within the ISO area. The conceptual statewide plan takes a whole-state perspective to identify potential upgrades or additions needed to meet state and federal policy requirements such as renewable energy targets. Whenever possible, the ISO will perform this activity in coordination with regional planning groups and neighboring balancing authorities. For the previous and current planning cycles, the ISO has developed its conceptual statewide plan in coordination with other California planning authorities and load serving transmission providers under the structure of the CTPG. Although the transmission planning group does not formally approve specific transmission projects for development, its members perform important technical studies and issue a coordinated plan that provides specific project suggestions that each participating planning entity can consider for incorporation into its own transmission plan. The ISO's conceptual statewide plan, which is based on the CTPG efforts, thus represents an important input to phase 2 of the planning process.

The ISO formulates the public policy-related resource portfolios[2] in collaboration with the CPUC, with input from other state agencies such as the CEC and the municipal utilities within the ISO balancing authority area. The CPUC plays a primary role in the formulation of resource portfolios as the agency that oversees the supply procurement activities of the investor-owned utilities and the retail direct access providers, which collectively account for 95 percent of the energy consumed annually within the ISO area. The proposed portfolios are reviewed with stakeholders to seek their comments which are then considered for incorporation into the final portfolios.

The resource portfolios play a crucial role in the identification of public policy-driven transmission elements, which is best illustrated by considering the RPS goal. Achieving the RPS goal will entail developing substantial amounts of new renewable generating capacity, which will in turn require new transmission to deliver the renewable energy to consumers. At this time, however, there is a great deal of uncertainty about which areas of the grid will actually realize the most new resource development. The ISO must therefore plan new policy-driven transmission elements in a manner that recognizes this uncertainty and balances the requirement to have needed transmission completed and in service in time to meet the RPS by 2020 against the risk of building transmission in areas that do not realize enough new generation to justify the cost of such transmission. The planning process manages this uncertainty problem by applying a “least regrets” principle, which first formulates several alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio followed by selecting for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios. The least regrets approach is discussed further in the section on phase 2 below.

1.2.2 Phase 2

In phase 2, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO controlled grid. The comprehensive transmission plan specifies the transmission upgrades and additions needed to meet the infrastructure needs of the grid. This includes the reliability and economically-driven categories as well as the new public policy-driven category to support state and federal policy requirements and directives. In phase 2, the ISO conducts the following major activities:

1. Performs technical planning studies as described in the phase 1 study plan and posts the study results;
2. Provides a request window for submission of the following: reliability project proposals in response to the ISO’s technical studies, Location Constrained Resource Interconnection Facilities (LCRIF) project proposals, demand response storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs and Merchant Transmission Facility project proposals;

[2] As noted above, for the 2011/2012 planning cycle the formulation of resource portfolios occurred during TPP phase 2. In the future, however, starting with the 2012-2013 planning cycle this activity will be part of phase 1.

3. Completes the conceptual statewide plan if it is not completed in phase 1, which is also used as an input during this phase, and provides stakeholders an opportunity to comment on that plan;
4. Evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the ISO's final comprehensive transmission plan;
5. Coordinates with renewable integration studies performed by the ISO for the CPUC long-term procurement proceeding. Renewable integration studies are considered for determining requirements for policy-driven transmission elements needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
6. Reassesses, as needed, significant transmission upgrades and additions starting with the 2011/2012 planning cycle that were identified in completed GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
7. Performs a "least regrets" analysis of potential policy-driven additions and upgrades to identify those elements that should be approved as category 1 transmission elements, based on balancing the two objectives of minimizing the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
8. Identifies additional category 2 policy-driven additions and upgrades that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
9. Once the reliability projects and policy-driven elements have been identified, performs economic studies to identify economically beneficial transmission elements to be included in the final comprehensive transmission plan;
10. Performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling which is commonly referred to as once through cooling; and AB1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin.
11. Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and
12. Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan to post in draft form for stakeholder review and comment at the end of January and present to the ISO Board for approval at the conclusion of phase 2 in March.

The comprehensive transmission plan distinguishes between and includes transmission projects and transmission elements. Transmission projects are those additions and upgrades for which an approved project sponsor is specified pursuant to ISO tariff provisions, whereas transmission elements are facilities that will be subject to a competitive solicitation in phase 3 to select a project sponsor. The transmission projects include reliability-driven projects,[3] location constrained resource interconnection facility projects, transmission projects needed to maintain the feasibility of long-term congestion revenue rights, merchant transmission projects, and certain GIP-driven network upgrades. Transmission elements, in contrast, are specific transmission additions and upgrades needed to either: 1) meet state and federal policy requirements and directives, including renewable policies, that are not inconsistent with the Federal Power Act (policy-driven transmission elements); or 2) reduce congestion costs, production supply costs, transmission losses or other electric supply costs resulting from improved access to cost-effective resources (economically-driven elements). With certain exceptions, these transmission elements will not have an approved project sponsor at the time the ISO presents the comprehensive transmission plan to its Board for approval, but instead will be subject to an open solicitation process conducted in phase 3 to determine who will construct and own these transmission elements.[4] In the phase 3 open solicitation, all interested project sponsors will have an opportunity to submit proposals to construct and own these transmission elements.

In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven elements. The use of these categories will better enable the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. Failure to explicitly manage these uncertainties in the planning process would increase the risk of over-building capacity in some areas while under-building in others. For example, with respect to meeting the state's 33 percent RPS, key uncertainties include the locations of the new renewable resources and other new generation that will be coming on line over the next 10 years, and the commercial operation dates of such generation. In light of these uncertainties, the ISO may identify a set of category 1 policy-driven elements that the ISO concludes will minimize the risk of building under-utilized transmission capacity, based on a least regrets evaluation of alternative generation development scenarios or portfolios. The criteria to be used for this evaluation are identified in Section 24.4.6.6 of the revised tariff.

Although category 1 elements are those least regrets infrastructure additions and upgrades most likely to be needed under multiple renewable portfolio scenarios, the ISO may need to identify additional transmission elements which might be needed to achieve the 33 percent target depending on future commercial interest in one of the renewable resource areas that did not feature significantly in the least regrets analysis.

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[3] Pursuant to FERC's October 20, 2011 Order on Compliance, the ISO will further divide the reliability-driven projects into two categories: one will be the responsibility of a PTO to build and own, and the other will be open to competitive solicitation in Phase 3 of the planning process.

[4] According to tariff Section 24.5.2, transmission elements that involve upgrades or additions to existing PTO facilities, construction or ownership on a PTO right-of-way, or upgrades or additions to an existing substation will be the responsibility of the PTO to construct and own.

For such elements there would be no immediate conclusive findings of the need, and therefore they may be identified as category 2 to be re-evaluated in the next planning cycle based on more up-to-date information (e.g., new evidence of generation development in a previously less developed area) to determine whether they would become category 1 facilities.

When the Board approves the comprehensive transmission plan at the end of phase 2, its approval will constitute a finding of need and an authorization to develop the category 1 policy-driven elements and the economically-driven elements in the plan. The Board's approval authorizes implementation and enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval under current tariff provisions.[5] As indicated above, in phase 3 the ISO will solicit and accept proposals from all interested project sponsors to build and own the approved policy-driven and economically-driven transmission elements that are open to competition.

By definition, the category 2 elements in the comprehensive plan will not be authorized to proceed further when the ISO Board approves the plan, but will instead be identified for a re-evaluation of need during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the ISO will determine whether the category 2 elements now satisfy the least regrets criteria and should be elevated to category 1 status, should remain category 2 projects for another cycle, or should be removed from the transmission plan.

As noted earlier, phases 1 and 2 of the ISO's transmission planning process encompass a 15-month period. Thus the last three months of phase 2 of one planning cycle will overlap phase 1 of the next cycle, which also spans three months. The ISO will conduct phase 3, the competitive solicitation for sponsors to build and own eligible policy-driven and economically-driven elements of the final plan, following Board approval of the comprehensive plan and in parallel with the start of phase 2 of the next annual cycle.[6]

1.2.3 Phase 3

Phase 3 will take place after the approval of the plan by the ISO Board if projects eligible for competitive solicitation were approved by the Board in the draft Plan at the end of phase 2. Projects eligible for competitive solicitation are Category 1 policy-driven or economically-driven elements, or reliability projects that have additional policy or economic benefits, excluding projects that are modifications to existing facilities or utilizing existing rights of way owned by incumbent transmission owners. The ISO filed its criteria for making these determinations on December 2, 2011, in response to the Commission's October 20, 2011 order in this regard. The Commission issued its ruling on the criteria on February 1, 2012.

[5] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. Under the revised planning process, such projects would be included in the comprehensive plan as pre-approved by ISO management and not requiring further Board approval.

[6] These details are set forth in the BPM for Transmission Planning.

The ISO evaluates the projects against its criteria prior to the Board approval of the transmission plan. If eligible projects are determined, phase 3 will start approximately in April of 2012 when the ISO will open a project submission window for the entities who propose to sponsor the identified transmission elements. At the close of this submission window, the ISO will evaluate the proposals and, if there are multiple eligible projects submitted for the same elements and these projects are subject to siting by different governmental agencies, the ISO will select the project sponsor to construct and own the transmission upgrades or additional elements. Single proposed project sponsors who meet the eligibility criteria, as well as multiple eligible project sponsors whose projects are subject to the same governmental siting authority, can move forward to project permitting and siting.

1.3 TPP-GIP Integration Initiative in Progress

The ISO currently has a stakeholder policy initiative underway that will result in greater integration between the transmission planning process and the generation interconnection procedures. Under current tariff provisions, the GIP and TPP are largely parallel and separate processes with different study approaches and project approval criteria. Yet both processes can result in the identification and approval of major, costly transmission additions and upgrades to be built at ratepayer expense. Therefore, a primary objective of this initiative, referred to as “TPP-GIP Integration”, is to better consolidate the two processes so that decisions to build significant ratepayer-funded transmission upgrades are made holistically in conjunction with other transmission needs identified in the comprehensive transmission planning process.

A second, equally important objective of TPP-GIP integration is to use the planning process to determine which interconnection-driven facilities will be paid for by ratepayers, so that interconnection customers will be responsible for the cost of any incremental upgrades they need in addition to the facilities approved under the comprehensive transmission plan. This important change in cost allocation for interconnection-driven network upgrades will bring the ISO into alignment with the practices of other organized markets. It will also help reduce the risk to ratepayers of paying for transmission in excess of actual needs and will place incentives on resource developers to select interconnection locations that will utilize ratepayer-funded transmission as far as possible, resulting in more efficient use of the grid.

The ISO intends to finalize its proposal for this initiative and present it to the Board for approval in May of 2012. Assuming the proposal is approved by FERC, the ISO will implement these changes during the 2012-2013 transmission planning cycle and in the next interconnection queue cluster, which closes to new interconnection requests in 2012. The impact of the changes will be primarily on the study processes, cost allocation and other provisions of the GIP. The impact on the planning process will be minimal, because the ISO is proposing to rely on existing planning provisions and activities associated with the public policy-driven transmission category as the vehicle for identifying ratepayer-funded transmission to support access to needed new generating resources. If the TPP-GIP integration initiative receives FERC approval on the intended timetable, the ISO will provide a detailed discussion of the resulting changes in the 2012-2013 comprehensive transmission plan. Additional information about the initiative may be obtained from the ISO website.[7]

[7] http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionPlanning_GenerationInterconnectionIntegration.aspx.

SECTION II: RELIABILITY ASSESSMENT

Chapter 2

Reliability Assessment – Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

The ISO annual reliability assessment is a comprehensive annual study that includes:

- power flow studies;
- transient stability analysis; and
- voltage stability studies.

The focus of the annual reliability assessment is to identify facilities that demonstrate a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.

The study is performed as part of the annual transmission planning process, in accordance with section 24 of the ISO tariff, and as defined in the Business Process Manual (BPM) for the Transmission Planning Process.[8] The study uses the Western Electricity Coordinating Council (WECC) full-loop power flow base cases. The detailed reliability assessment results are given in Appendix A.

2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

For the backbone system assessment, conventional and governor power flow and stability studies were performed to evaluate system performance under normal conditions and following contingencies of power system equipment of voltage levels 230 kV and above. The backbone transmission system studies include:

- Northern California — PG&E system;
- Southern California — SCE system; and
- Southern California — SDG&E system.

2.1.2 Local Area Assessments

For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for PG&E's eight local service territories. These areas are:

[8] https://bpm.caiso.com/bpm/bpm/version/000000000000137

- Humboldt;
- North Coast and North Bay;
- North Valley;
- Central Valley;
- Greater Bay;
- Greater Fresno;
- Kern; and
- Central Coast and Los Padres.

Other specific local areas within the Southern California Edison service territory were also studied. The San Diego Gas & Electric service territory was studied as one area.

2.2 Reliability Standards Compliance Criteria

The 2011/2012 transmission plan spans a 10-year planning horizon and was conducted to ensure the ISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and ISO planning standards across the 2012-2021 planning horizon. Sections 2.2.1 through 2.2.4 describe how these planning standards were applied for the 2011/2012 study.

2.2.1 NERC Reliability Standards

2.2.1.1. System Performance Reliability Standards (TPL-001 to TPL – 004)

NERC reliability standards set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the ISO as a registered NERC planning authority and were considered in the reliability assessment:[9]

- TPL-001: System Performance Under Normal Conditions (category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (category B);
- TPL-003: System Performance Following Loss of Two or More BES Elements (category C); and
- TPL-004: System Performance Following Extreme BES Events (category D).

2.2.1.2. Nuclear Plant Interface Coordination (NUC-001-2)

The purpose of this standard is to ensure coordination between the nuclear plant generator operators and transmission entities to ensure safe operation and shutdown of the nuclear plant. The NUC-001-2 standard requires transmission planners and planning coordinators to perform planning studies and analyses in accordance with the Nuclear Plant Interface Requirements, Appendix E of the Transmission Control Agreement and the coordination agreements that the ISO has in place with the nuclear

[9] http://www.nerc.com/page.php?cid=2%7C20

plant generator operators and the applicable participating transmission owners.[10,11] These agreements provide voltage requirements, as well as stability requirements, for the off-site power supply to the Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS) under various generating or transmission contingency conditions.

2.2.2 WECC Regional Criteria

The WECC TPL system performance criteria is applicable to the ISO as a planning authority and sets forth additional requirements that must be met under a varied but specific set of operating conditions.[12]

2.2.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[13] These standards cover the following:

- address specifics not covered in the NERC reliability standards and WECC regional criteria;
- provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

The ISO Board approved, at the July 2011 Board meeting the latest revision of the ISO planning standards. They have been developed through an open stakeholder process and encompass the following changes from the 2002 version:

1. removed one outdated planning standard (the San Francisco/Greater Bay Area generation outage standard);
2. added three new standards pertaining to applicability of reliability standards to the entire ISO controlled grid, requirements for voltage levels, and contingency treatment of combined cycle power plant outages;
3. provided updates and enhancements to the existing planning standard for the involuntary load shedding standard; and
4. included modifications to the guidelines for special protection systems.

2.3 Study Methodology and Assumptions

Sections 2.3.1 and 2.3.2 summarize the study methodology and assumptions used for the reliability assessment.

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10 http://www.nerc.com/files/NUC-001-2.pdf
11 http://www.caiso.com/Documents/TransmissionControlAgreement-Updatedas-Dec3_2010.pdf
12 http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
13 http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

2.3.1 Study Methodology

As noted earlier, the assessment of the backbone and local areas were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.1.1 Generation Dispatch

All generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels. Qualifying Facilities (QFs) and self-generating units were modeled based on their historical generating output levels.

2.3.1.2 Power Flow Contingency Analysis

Conventional and governor power flow contingency analyses were performed on all backbone and local areas consistent with NERC TPL-001 through TPL-004, WECC regional criteria and ISO planning standards as outlined in section 2.2. Transmission line and transformer bank ratings in the power flow cases were updated to reflect the rating of the most limiting component or element. All power system equipment ratings were consistent with information in the ISO Transmission Register.

Based on historical forced outage rates of combined cycle power plants on the ISO-controlled grid, the G-1 contingencies of these generating facilities were classified as an outage of the whole power plant, which could include multiple units. Examples of such power generating facilities are the Delta Energy Center, which is composed of three combustion turbines and a single steam turbine.

2.3.1.3 Post Transient Analyses

For the ISO controlled-grid backbone system assessment, post transient analyses were performed to ascertain compliance with the WECC post transient voltage deviation criteria. The WECC criteria specify maximum post transient voltage deviation of 5 percent and 10 percent for Categories B and C contingencies, respectively, of allowable effects on other systems. The 5 percent WECC criterion was not used in the post transient analyses of the SCE system. Instead, consistent with the SCE guidelines for 7 percent deviation requirements for N-1[14] contingencies, the 7 percent and 10 percent voltage deviation guidelines were applied for the N-1 and N-2 contingency analyses respectively. The SCE's post transient voltage deviation guidelines apply to its own system and not to other systems. For impacts on other systems, all PTOs follow WECC criteria on post transient voltage deviations.

2.3.1.4 Transient Stability Analyses

Transient stability simulations were also performed as part of the backbone system assessment to ensure system stability and positive dampening of system oscillations for critical contingencies. This ensured that the transient stability criteria for performance levels B and C as shown in table 2.3-1 were met.

[14] N-1 is a single transmission circuit outage.

Table 2.3-1: WECC transient stability criteria[15]

Performance Level	Disturbance	Transient Voltage Dip Standard	Minimum Transient Frequency Standard
B	Generator	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.	Not below 59.6 Hz for 6 cycles or more at a load bus.
	One Circuit		
	One Transformer		
	PDCI		
C	Two Generators	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below 59.0 Hz for 6 cycles or more at a load bus.
	Two Circuits		
	IPP DC		

2.3.2 Study Assumptions

The following study horizon and assumptions were modeled in the 2011/2012 transmission planning analysis.

2.3.2.1 Study Horizon

The NERC standards, TPL-001 through TPL-003 (noted in section 2.2.1) and compliance-related studies were performed for the near-term (i.e., years 2012 through 2016) and the long-term (i.e., year 2021) scenarios. Additional studies for the NERC TPL-004 standards, which relate to extreme system events, were performed for the near-term (2015) scenarios only.

2.3.2.2 Peak Demand

In 2011, the ISO-controlled grid peak demand was 45,545 MW and occurred on September 7, 2011 at 4:30 p.m. The peak demand for PG&E of 19,791 MW occurred on June 21, 2011 at 4:49 p.m. SCE and SDG&E peak demands occurred on the same date as the ISO's but at different times: for SCE, it occurred on September 7, 2011, at 3:52 p.m. with 23,388 MW; and for SDG&E, it occurred on September 7, 2011, at 1:57 p.m. with 4,378 MW.

Most of the ISO-controlled grid experiences summer peaking conditions. Hence, summer peak conditions were the focus in all studies. For areas that experienced highest demand in the winter season or where historical data indicated other conditions may require separate studies, winter peak and summer off-peak studies were also performed. Examples of such areas are Humboldt, Greater Fresno and the

[15] http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20through%20004%20-WECC-1-CR%20-%20System%20Performance%20Criteria%20Effective%20April%2018%202008.pdf

Central Coast in the PG&E service territory. Table 2.3-2 summarizes these study areas and the corresponding peak scenarios for the reliability assessment.

Table 2.3-2: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	2012 through 2016	2021
Humboldt	Summer Peak Winter Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter Peak	Summer Peak Winter Peak
North Valley	Summer Peak	Summer Peak
Central Valley	Summer Peak	Summer Peak
Greater Bay Area	Summer Peak	Summer Peak
Fresno	Summer Peak Summer Off-Peak	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak	Summer Peak Winter Peak
Northern California (PG&E) Bulk System*	Summer Peak Summer Off-Peak	Summer Peak
Southern California Edison (SCE) area	Summer Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak	Summer Peak
Entire Southern California*	Summer Peak Summer Off-Peak	Summer Peak Summer Off-Peak

**The studies in these areas were conducted on 2016 and 2021 scenarios only*

2.3.2.3 Stressed Import Path Flows

The ISO balancing authority is interconnected with neighboring balancing authorities through interconnections over which power can be imported to or exported from the ISO area. The power that flows across these import paths are an important consideration in developing the study base cases. For the 2011/2012 planning study, and consistent with operating conditions for a stressed system, high import path flows were modeled to serve the ISO's BAA load. These import paths are discussed in more detail in section 2.3.2.10.

2.3.2.4 Contingencies

In addition to studying the system under TPL-001 (normal operating conditions), the following provides additional detail on how the TPL-002, TPL-003 and TPL-004 standards were evaluated.

TPL-002

For this standard the loss of a single BES element was studied. This included loss of one generator (G-1); one transformer (T-1); one transmission line (L-1) DC lines; and a selected loss of one generator, one transmission line (G-1/L-1), outages of all transmission facilities in the ISO controlled-grid of voltage levels 115 kV and above, and most of the 60 kV, 69 kV and 70 kV facilities. The outages of transmission facilities that comprise the import paths with neighboring balancing authorities were also studied. The list of contingencies was provided on the ISO secured website.

TPL-003

For this standard the loss of two or more BES elements was studied. This included the loss of two transmission facilities in the same corridor, double circuit tower line (DCTL) outages, loss of two nuclear units and a large number of two element outages (i.e., C-3 contingencies). In general, because many of the transmission facilities evaluated under the TPL-003 standard are major paths designed to transfer large amounts of power, the results of the analysis were considered more severe and more critical than many of the other category C outages studied as part of the 2011-2012 study. The impact of outages of two or more elements that resulted from a combination of two category B outages at voltage levels of 60 kV and above were also evaluated for a number of the local area studies;

TPL-004

For this standard, selected extreme events were studied and results are provided in this report. Category D extreme events studied included:

- outage of the California-Oregon Intertie (COI) and Northeast/Southeast (NE/SE) system separation, which is addressed in the PG&E bulk transmission system assessment;
- outage of Path 26 that included an outage of the three Midway-Vincent 500 kV lines, which is addressed in the PG&E bulk transmission system assessment;
- loss of Lugo 500/230 kV substation addressed in the SCE system assessment;
- common corridor outage addressed in the SDG&E system assessment.

It should also be noted that during the 2008/2009 planning process, the ISO performed a detailed assessment of the most severe category D outages in the ISO balancing authority area. The results from this analysis were documented in the 2010 transmission plan.[16] The results documented in this report satisfy the TPL-004 standard requirement 1.3.1 as well as the requirement for this 2011-2012 transmission plan.

2.3.2.5 Generation Projects

The ISO modeled approximately a 20 percent renewable energy scenario for the 2016 reliability study case. This study case included the renewable generation and associated transmission in the ISO queue that was in either of the following stages and was expected to be in service by 2016:

[16] 2010 Final California ISO Transmission Plan at http://www.ISO.com/2771/2771e57239960.pdf

For the 2021 reliability study cases, the ISO modeled the base 33 percent RPS portfolio from the 2010-2011 Transmission Plan. This portfolio is described in Chapter 4 of the 2010-2011 ISO Transmission Plan. However, in some areas where renewable generation modeling was substantial, some sensitivity studies were performed without any expected renewable generation modeled. These sensitivity studies were performed to address the possibility that the modeled renewable generation would not actually be built or would not be operating due to very low intermittent wind and insolation levels.

Approximately 30 percent of California's in-state generating capacity (gas and nuclear power) uses coastal and estuarine water for once-through cooling. On May 4, 2010, the State Water Resources Control Board adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy establishes uniform, technology-based standards to implement federal Clean Water Act section 316(b), which requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. It required the owner or operator of an existing non-nuclear fossil fuel power plant using once-through cooling to submit an implementation plan to the SWRCB on April 1, 2011. In most cases, the implementation plans selected an alternative that would achieve compliance by a date specified for each facility identified in the policy. However, most of the implementation plans were contingent on future commercial arrangements.

Due to the uncertainty regarding future commercial arrangements associated with OTC implementation plans, the ISO continued to include most OTC generation in the reliability models. However, many of the OTC units were not dispatched, and some were not modeled at all if firm information was available regarding unit retirements. The specific retirement assumptions are documented in the local area descriptions later in this chapter.

2.3.2.6 Transmission Projects

The study included all existing transmission projects in service and the expected future transmission projects that have been approved by the ISO but are not yet in service. Refer to Tables 7.1.1 and 7.1.2 of chapter 7 (Transmission Project Updates) for the list of projects that were modeled in the base cases but that are not yet in service. Also included in the study cases were generation interconnection transmission related projects that were included in executed generator interconnection agreements (LGIA) for generation projects included in the base case.

2.3.2.7 Load Forecast

The local area load forecasts used in the study were developed by the participant transmission owners using the CEC-approved load forecast in December 2010 as the starting point because the load forecast from the CEC did not provide the bus-level demand projections.[17] The 1-in-10 load forecasts were modeled in each of the local

[17] http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html

area studies. The 1-in-5 coincident peak load forecasts were used for the northern area backbone system assessment as it covers a vast geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

Light Load Conditions

The assessment evaluated the light load conditions in various parts of the ISO balancing authority to satisfy NERC compliance requirement 1.3.6 for TPL-001, TPL-002 and TPL-003. The ISO light load conditions in various local areas of the system ranged from 35 percent to 65 percent of the summer peak load in that area. In most cases, the impacts under light load conditions were less severe than those under peak load conditions.

Some of the local areas were not evaluated for light load conditions because they were known through previous studies to have less severe impacts or no impacts on the system as compared to impacts under peak load conditions. The ISO therefore relied upon the discretion allowed under requirement 1.3.1 of TPL-001 and 1.3.2 of TPL-002 and TPL-003 to limit evaluation of such areas only for peak load conditions.

2.3.2.8 Reactive Power Resources

Existing and new reactive power resources were modeled in the base cases for the study to ensure realistic reactive power support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. Readers should refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include:

- all shunt capacitors in the SCE service territory; and
- static var compensators or static synchronous compensator (STATCOM) at several locations such as Potrero, Newark, Rector, Devers and Talega substations.

For a complete list of these resources, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[18]

2.3.2.9 Operating Procedures

ISO operating procedures for the system under normal (pre-contingency) and emergency (post-contingency) conditions were observed in this study. Table 2.3-3 summarizes major operating procedures that are utilized in the ISO-controlled grid.

[18] This site is available to market participants who have submitted a Non-Disclosure Agreement (NDA) and is approved to access the portal by the ISO. For instructions, go to http://www.caiso.com/Documents/Regional%20transmission%20NDA.

Table 2.3-3: Operating procedures for normal and emergency conditions

Operating Procedure	Scope
7810	San Diego Area Generation Requirements
7620	South of Lugo Generation Requirements
7630	Orange County Area Requirements
7310	Bay Area Generation Commitment
7570	South of Lugo 500 kV lines
6110	COI Master Operating Procedure
7430	Fresno Area
6510	Southern California Import Transmission (SCIT)

2.3.2.10 Firm Transfers

Power flow on the major power transmission paths was considered and modeled as a firm transfer on the major import paths into the ISO BAA. In general, the northern California system has two major power transfer paths into the ISO BAA (i.e., Path 66 and Path 26). Table 2.3-4 lists the transfer capability and power flows that were modeled in each scenario on these paths in the northern area assessment for both the 2016 and 2021 base cases. Negative flow in table indicates a reversal of flow direction than indicated for the path.

Table 2.3-4: Major paths and power transfer capabilities in the Northern California assessment

Import Path	2016 Summer Peak	2016 Summer Off-Peak	2021 Summer Peak
California-Oregon Intertie Flow (N-S) (MW)	4,800	1009	4,800
Pacific DC Intertie Flow (N-S) (MW)	3,000	0	3,100
Path 15 Flow (N-S) MW	-359	5,400	871
Path 26 Flow (N-S) MW	4,000	-1,769	4,000
Northern California Hydro % dispatch of nameplate	80%	n/a	80%

Table 2.3-5 lists the major paths in the SCE service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-5: Major paths and power transfer capabilities for the SCE area assessment

Import Path	2016 Summer Peak	2016 Spring Off-Peak	2021 Summer Peak
Path 26 Flow (N-S) (MW)	3,980	1,314	3,087
West of River (E-W) (MW)	8,224	8,377	9,669
East of River (E-W) (MW)	4,810	5,086	4,982
Pacific DC Intertie Flow (N-S) (MW)	3,000	3,000	3,084

Table 2.3-6 lists the major paths in the SDG&E service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-6: Major paths and power transfer capabilities for the SDG&E area assessment

Import Path	Path Flow (MW)	
	2016 Summer Peak	2021 Summer Peak
Midway-Los Banos (Path 15)	-200	1602
Arizona-California (Path 21)	2715	2370
Northern-Southern California (Path 26)	4000	3272
IPP DC (Intermountain-Adelanto)	1804	1928
Sylmar-SCE	510	687
IID-SCE	394	692
North of San Onofre	1521	1368
South of San Onofre	628	782
ISO-Mexico (CFE)	-1.8	1.4
West of Colorado River (WOR)	5254	5022
East of Colorado River (EOR)	4035	3743
Lugo-Victorville 500 kV line	1113	1013
Eldorado-Mc Cullough 500 kV line	-224	200
Perkins-Mead 500 kV line	74	199

2.3.2.11 Protection Systems

To ensure reliable operation of the system, many remedial action schemes (RAS) or special protection systems (SPS) have been installed in certain areas of the system. These protection systems drop load or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Table 2.3-7 – 2.3.9 lists a sample of the SPS that were modeled and included in the study by area.

Table 2.3-7: A sample of protection systems modeled for the PG&E area reliability assessment

No.	RAS / SPS Name	Descriptions	Study Area
1	Middletown UVLS	Trip Middletown substation load under low voltages conditions.	PG&E-North Coast/North Bay
2	Humboldt SPS	Trip load in Humboldt under low voltages conditions.	PG&E-Humboldt Area
3	Alameda Overload SPS	Drops City of Alameda load following the overload of Oakland cables.	PG&E-Greater Bay Area
4	Bay Area UVLS	Trip local distribution load when detects low 230 kV voltage at Newark, Monta Vista, San Mateo.	PG&E-Greater Bay Area
5	Bay Meadows Overload SPS	Trip one or two Bay Meadows distribution feeders after loss of any San Mateo-Bay Meadows 115 kV line.	PG&E-Greater Bay Area
6	Eastshore 230/115 kV TB #1 and #2 Overload SPS	Trip & Lock Out (T&LO), and initiate breaker failure on the associated transformer high and low side breakers if loading above emergency rating. Scheme is normally cut out except for specific clearances.	PG&E-Greater Bay Area
7	Evergreen - San Jose B Overload	Trip San Jose CBs 112, 122 following the overload on Evergreen-San Jose B.	PG&E-Greater Bay Area
8	Gilroy Energy Center SPS	Trip up to 51 MW gen at Gilroy Energy Center if overload on Llagas-Morgan Hill or Llagas-Metcalf 115 kV lines.	PG&E-Greater Bay Area

No.	RAS / SPS Name	Descriptions	Study Area
9	Grant-Eastshore Overload SPS	Trip Grant feeder breakers 1105 & 1108 if overload on Grant-Eastshore #1, #2	PG&E-Greater Bay Area
10	Metcalf-El Patio Overload SPS	Trip El Patio CB 142 (El Patio - SJ A) if Load > 960 A on either Metcalf-El Patio #1 or #2 115 kV line.	PG&E-Greater Bay Area
11	Metcalf SPS	Trip load and curtail generation following the loss of Moss Landing-Metcalf or Metcalf-Tesla.	PG&E-Greater Bay Area
12	Monta Vista N-2 Overload SPS	Trip Monta Vista-Jefferson #1 and #2 230 kV lines following loss of both Monta Vista #3 and #4 230 kV lines.	PG&E-Greater Bay Area
13	Moraga-Oakland J Overload SPS	Trip Oakland J CB 122 (Jenny) if load > 750 A on Moraga-J.	PG&E-Greater Bay Area
14	Newark Dumbarton Overload SPS	Trip Dumbarton CB 132 if overload on Newark-Dumbarton 115	PG&E-Greater Bay Area
15	San Francisco RAS	Trip Area Load after NERC Cat D loss of area generation or transmission.	PG&E-Greater Bay Area
16	South of San Mateo SPS	Trip up to 600 MW of load in the peninsula if 115 kV line overload caused by N-2 230 kV outages.	PG&E-Greater Bay Area
17	Paso Robles UVLS	Drop load at Paso Robles Substation to mitigate any voltage collapse concerns for the loss of Paso Robles-Templeton 70 kV line.	PG&E-Los Padres Area
18	Mariposa UVLS	Trip load in the area if under voltages detected.	PG&E San Joaquin Valley
19	Ashlan 230 kV UVLS	Trip load in the area if under voltages detected.	PG&E San Joaquin Valley

No.	RAS / SPS Name	Descriptions	Study Area
20	McCall 230 kV UVLS	Trip load in the area if under voltages detected.	PG&E San Joaquin Valley
21	Stagg UVLS	Monitor the Stagg 230 kV bus voltage and curtail load to mitigate post-contingency low voltage problems, which could result from a sustained outage to the Tesla-Stagg and Tesla-Eight Mile Road 230 kV line.	PG&E - Stockton Area
22	Yolo 115 kV UVLS	Trip load in the Woodland area if under voltages detected.	PG&E Sacramento Area
23	Figarden 230 kV UVLS	Trip load in the area if under voltages detected.	PG&E San Joaquin Valley
24	Cascade Thermal Overload Scheme	An SPS to open the Crag View - Cascade 115 kV intertie to protect thermal overload on the Cascade - Benton-Deschutes 60 kV line.	PG&E North Valley Area
25	Caribou PH Thermal Overload Scheme	An SPS to protect the Caribou-Palermo 115 kV line from thermal overload by tripping generation in the Caribou area.	PG&E North Valley Area

Table 2.3-8: A sample of protection systems modeled for the SCE area reliability assessment

No.	RAS / SPS Name	Descriptions	Study Area
1	SCE's "MWD Eagle Mountain Thermal Overload Protection Scheme"	The thermal overload relay will trip Eagle Mountain-Julian Hinds if an overload is detected on the Iron Mountain-Eagle Mountain 230 kV line.	SCE
2	West of Devers Overload Protection Scheme ("WOD SPS")	The WOD SPS was put in service in June 2007. The objective of this scheme is to mitigate the existing overloads on West of Devers 230 kV lines. The WOD SPS includes tripping of two Devers 500/230 kV AA transformer banks under certain system configuration.	SCE
3	South of Lugo N-2 SPS	This remedial action scheme was put into operation in June 2005 to trip up to 3 "A" station loads (Mira Loma, Padua and part of Chino) for a total of about 1,100 MW to 1,400 MW if any two 500 kV lines were lost on the South of Lugo path.	SCE
4	Blythe RAS	This RAS is used to prevent low voltages or line overloads in the Iron Mountain/Eagle Mountain/Julian Hinds area.	SCE
5	Low Voltage Load Shedding (LVLS) Scheme.	This remedial action scheme was put into operation in the mid-1980s to prevent a low-voltage condition resulting from the simultaneous loss of the Lugo-Mira Loma #2 and #3 and Lugo-Serrano 500 kV (or Lugo-Rancho Vista, after Lugo-Serrano is looped in).	SCE

Table 2.3-9: A sample of protection systems modeled for the SDG&E area reliability assessment

No.	RAS / SPS Name	Descriptions	Study Area
1	500 kV TL 50001 IV Generator SPS	Trip generation at CLR II and TDM under contingency conditions.	SDG&E
2	Miguel transformer protection	Monitor the loss of transformer and the loading on the remaining transformer.	SDG&E
3	Otay Mesa-Tijuana SPS	A redundant scheme to protect the line from loading above its continuous rating.	SDG&E
4	TL 649 69 kV SPS	An SPS to protect TL 649 from thermal overload from an outage of TL 6910.	SDG&E

2.3.2.12 Control Devices

Control devices modeled in the study included key reactive resources listed in Section 2.3.2.8 and the direct current (DC) controls for the following lines:

- Pacific Direct Current Interface (PDCI);
- Inter-Mountain power plant direct current (IPPDC); and
- Trans Bay Cable project

For complete details of the control devices that were modeled in the study, please refer to the base cases that are available through the ISO Market Participant Portal Secured Website.

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

Figure 2.4.1-1 provides a simplified map of the PG&E Bulk Transmission System.

Figure 2.4.1-1: Map of PG&E Bulk Transmission System

The 500 kV bulk transmission system in northern California consists of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for excess resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. Additionally, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 (three 500 kV lines between Midway and Vincent Substations) is from north to south during on-peak load periods and in the reverse direction during off-peak load periods. Because of this bi-directional power flow pattern on the 500 kV Path 26 lines, both the summer peak (N-S) and off-peak (S-N) flow scenarios were analyzed. Transient stability and post transient contingency analyses were also performed for both flow patterns and scenarios.

2.4.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in chapter 2. The ISO-secured website lists the contingencies that were performed as part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided in the next sections. The studies for the PG&E Bulk Transmission System analyzed the most critical conditions: summer peak cases for the years 2016 and 2021 and summer off-peak case for 2016. All single and common mode 500 kV system outages were studied, as well as outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to ground faults.

Generation and Path Flows

The bulk transmission system studies used the same set of generation plants that were modeled in the local area studies. In this planning cycle, the study plan contemplates the scope of the study, which includes exploring the impacts of meeting the RPS goal in 2021 in addition to the conventional study that models new generators according to the CAISO guidelines for modeling new generation interconnection projects. Therefore, an additional amount of renewable resources was modeled in the 2016 and 2021 base cases according to the information in the ISO large generation interconnection queue. Only those resources that are proposed to be on line in 2016 or prior to 2016 were modeled in the 2016 cases.

Since the studies analyzed the most critical conditions, the flows on interfaces connecting Northern California with the rest of the WECC system were modeled at or close to the path’s flow limits. Table 2.4.2-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4.2-1: Major import flow for the northern area bulk study

Parameter	2016 Summer Peak	2016 Summer Off-Peak	2021 Summer Peak
California-Oregon Intertie Flow (N-S) (MW)	4,800	1,009	4,800
Pacific DC Intertie Flow (N-S) (MW)	3,000	0	3,100
Path 15 Flow (S-N) MW	-360	5,400	871
Path 26 Flow (N-S) MW	4,000	-1,769	4,000
Northern California Hydro % dispatch of nameplate	80%	n/a	80%

Load Forecast

Per the ISO planning criteria for regional transmission planning studies, the demand within the ISO area reflects a coincident peak load for 1-in-5-year heat wave conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50 percent of the 1-in-5 summer peak load level. Table 2.4.2-2 shows the assumed load levels for selected areas under summer peak and off-peak conditions.

Table 2.4.2-2: Load modeled in the bulk transmission system assessment

Scenario	Area	Load (MW)	Loss (MW)	Total (MW)
2016 Summer Peak	PG&E	30,244	1,110	31,354
	SDG&E	4,965	176	5,141
	SCE	24,882	564	25,446
	ISO	60,091	1,850	61,941
2016 Summer Off-Peak	PG&E	14,444	618	15,062
	SDG&E	3,461	73	3,534
	SCE	12,450	293	12,743
	ISO	30,355	984	31,339
2021 Summer Peak	PG&E	32,344	1,229	33,573
	SDG&E	5,457	187	5,644
	SCE	27,209	736	27,945
	ISO	65,010	2,152	67,162

Existing Protection Systems
Extensive special protection systems (SPS) or remedial action schemes (RAS) are installed in northern California area 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. A comprehensive detail of these protection systems are provided in various ISO operating procedures, engineering and design documents.

2.4.3 Study Results and Discussion

The studies were performed under normal and emergency system conditions and various scenarios with the primary focus on transmission systems in northern and central California. The 2016 and 2021 summer peak and 2016 summer off-peak cases were all found to satisfy the transient and post transient performance criteria. However, some thermal limits were exceeded during post transient contingency conditions in all three cases.

NUC-001: Nuclear Plant Interface Requirements (NPIRs)
The technical studies are performed annually in compliance with the NERC NUC-001-2 standard as a part of the ISO transmission plan. Post transient governor power flow and transient stability studies were conducted to assess the performance related to the Diablo Canyon Power Plant (DCPP) under normal and emergency conditions. In this planning cycle, the studies were conducted for the following scenarios:

- 2016 summer peak;
- 2016 summer off-peak; and
- 2021 summer peak.

Sixty-eight contingencies in the bulk system were studied, including the following:

- loss of a single Diablo unit (G-1);
- loss of two Diablo units (G-2);
- loss of one load block at Larkin Substation (largest load block in PG&E service territory according to the information in the base case);
- loss of entire load at Larkin Substation; and
- loss of critical 500 kV transmission lines, including the lines that connect Diablo Canyon PP with the transmission system, such as Gates-Diablo 500 kV line and Diablo-Midway 500 kV line, as well as other major inter-ties such as Malin-Round Mountain 500 kV lines or Midway-Vincent 500 kV lines.

The base cases modeled three transmission circuits to DCPP 500 kV switchyard and two transmission circuits to DCPP 230 kV switchyard with the status normally in-service. Each 500 kV line has the normal rating of 1,931 MVA. The study results showed the following:

- The steady state voltage at DCPP 230 kV switchyard was 234 kV under 2016 summer peak conditions, 234 kV under 2016 summer off-peak conditions and 232 kV under 2021 summer peak conditions.

- The steady state voltage at DCPP 500 kV switchyard was 529 kV under 2016 summer peak conditions, 528 kV under 2016 summer off-peak conditions and 528 kV under 2021 summer peak conditions.
- The DCPP generator output voltage was operated at 1.01 per unit under all conditions studied: 2016 and 2021 summer peak conditions and 2016 summer off-peak.
- The steady state frequency of the system was at 60.0 Hz.
- The study results showed no thermal overload, voltage or stability concerns related to the DCPP.

Figures 2.4.3-1 and 2.4.3-2 show voltage magnitude at Diablo 500 kV bus under summer peak and summer off-peak conditions in 2016. In addition, figures 2.4.3-3 through 2.4.3-8 show voltage and frequency at this bus following loss of two generators, two transmission lines and the entire load at Larkin.

Figure 2.4.3-1: Voltage at Diablo 500 kV bus under normal summer peak conditions in 2016

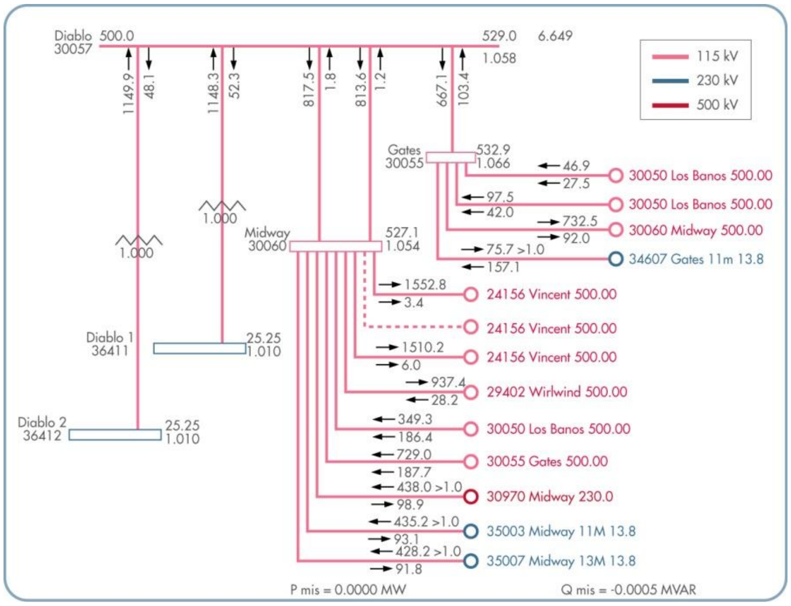


Figure 2.4.3-2: Voltage at Diablo 500 kV bus under normal summer off-peak conditions in 2016

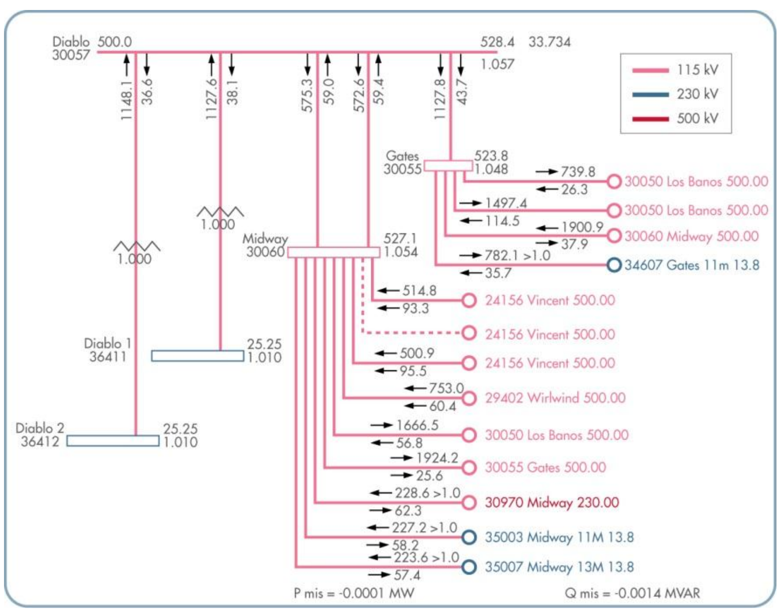


Figure 2.4.3-3: Voltage and frequency at Diablo 500 kV following the outage of Diablo G-2 under 2016 summer peak conditions

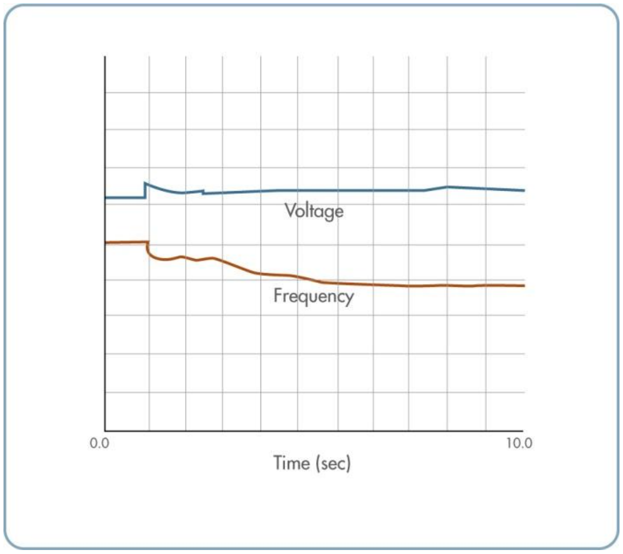


Figure 2.4.3-4: Voltage and frequency at Diablo 500 kV following the outage of Diablo G-2 under 2016 summer off-peak conditions

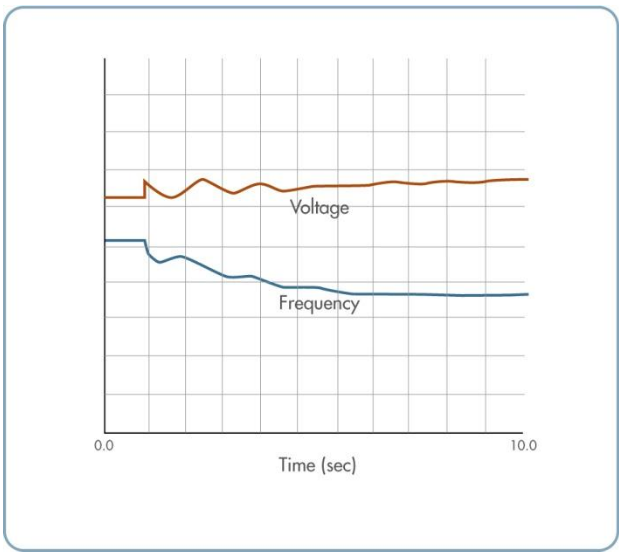


Figure 2.4.3-5: Voltage and frequency at Diablo 500 kV following the outage of Malin-Round Mountain double line outage under 2016 summer peak conditions

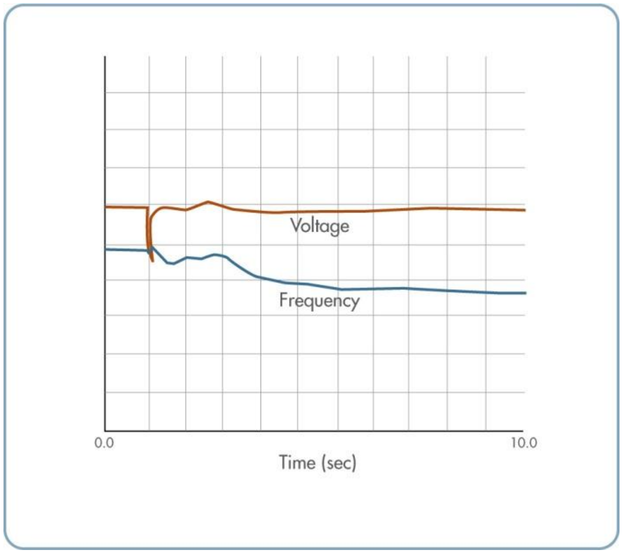


Figure 2.4.3-6: Voltage and frequency at Diablo 500 kV following the double line outage south of Los Banos under 2016 summer off-peak conditions

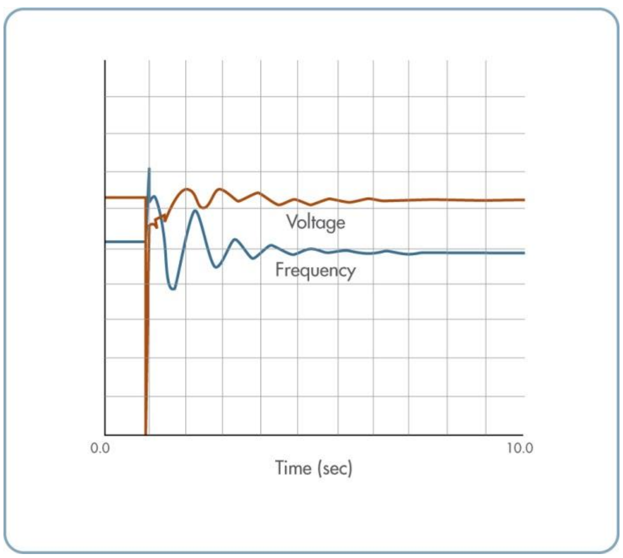


Figure 2.4.3-7: Voltage and frequency at Diablo 500 kV following the outage of entire load at Larkin substation under 2016 summer peak conditions

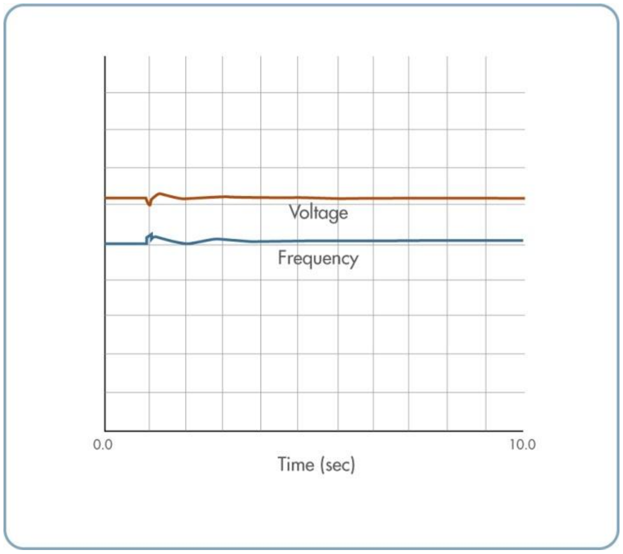
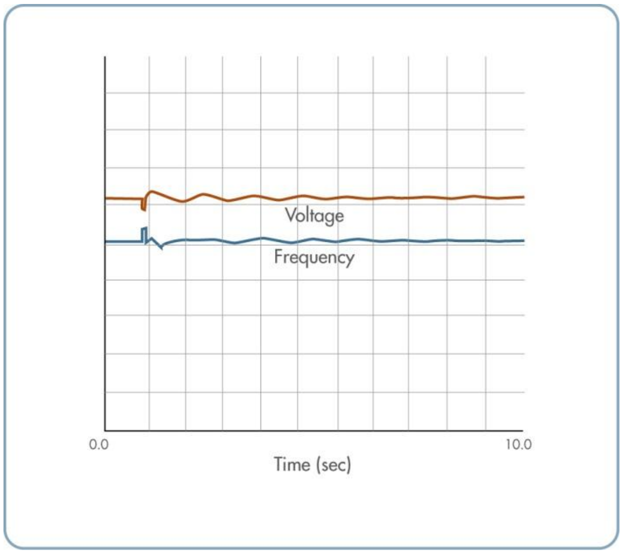


Figure 2.4.3-8: Voltage and frequency at Diablo 500 kV following the outage of entire load at Larkin substation under 2016 summer off-peak conditions



TPL 001: System Performance under Normal Conditions

For the summer peak cases, two facilities on the PG&E bulk system (230 kV and higher) were identified as overloaded under normal conditions in the 2021 study scenario. No overloads under normal conditions were identified in 2016. Voltages on the 500 kV system buses were within the acceptable limits according to PG&E operating procedure O-59. In general, this operating procedure provides a guideline that voltage ranges on the 500 kV buses in the PG&E system should be maintained between 495-551 kV. Transient simulation did not identify stability concerns under normal conditions.

For the summer off-peak case, no overload was identified. Voltages on the 500 kV system buses were within the acceptable limits. Transient simulation did not identify stability concerns under normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (L-1/G-1)

For the summer peak cases, no overloads were identified for the category B contingencies studied. No facilities were identified with voltage concerns under the category B performance requirement. The system was stable following these contingencies; there were no transient voltage or frequency violations.

For the summer off-peak case, two facilities were identified as overloaded for the category B contingencies, and no facilities were identified with voltage concerns under the category B performance requirement. The system remained stable following these contingencies; there were no transient voltage or frequency violations.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, one overload was identified under the category C contingencies studied in 2021, and two overloads were identified in 2016. No facilities were identified with voltage concerns under the category C performance requirement if all the required SPS are applied. The system remained stable following these contingencies; there were no transient voltage or frequency violations.

For the summer off-peak cases, two facilities were identified with thermal overloads and no facilities were identified with voltage concerns under the category C performance requirement. The system remained stable following these contingencies; there were no transient voltage or frequency violation.

Appendix A documents the worst thermal overload and low voltage concerns identified under summer peak and summer off-peak conditions along with the corresponding proposed solutions.

TPL 004: System Performance under Extreme Events

For category D contingencies, an outage of the California-Oregon Intertie (COI) and Northeast/Southeast (NE/SE) system separation was studied, as well as an outage of Path 26 that included an outage of the three Midway-Vincent 500 kV lines. Post-transient and transient stability studies were performed for these outages for the summer peak case of 2016. COI flow was modeled at 4,800 MW and Path 26 flow was modeled at 4,000 MW.

For the COI outage, the remedial action scheme (RAS) for NE/SE system separation was applied. This RAS includes opening ties between California and other areas and between Arizona and Utah, and creating two islands: one north of California-Oregon border, including Oregon, Idaho and Wyoming and the southern island encompassing California, Arizona and New Mexico. The studies of the COI outage showed that although some parts of the system were unstable, the northern and southern parts of California still maintained their integrity, but had voltage and frequency oscillations.

Frequency settled in the southern island at 59.53 HZ, and in the northern island at 60.18 HZ. Voltage and frequency on the major 500 kV buses is shown in figures 2.4.3-9, 2.4.3-10 and 2.4.3-11.

Figure 2.4.3-9. Voltage on 500 kV buses with NE/SE separation

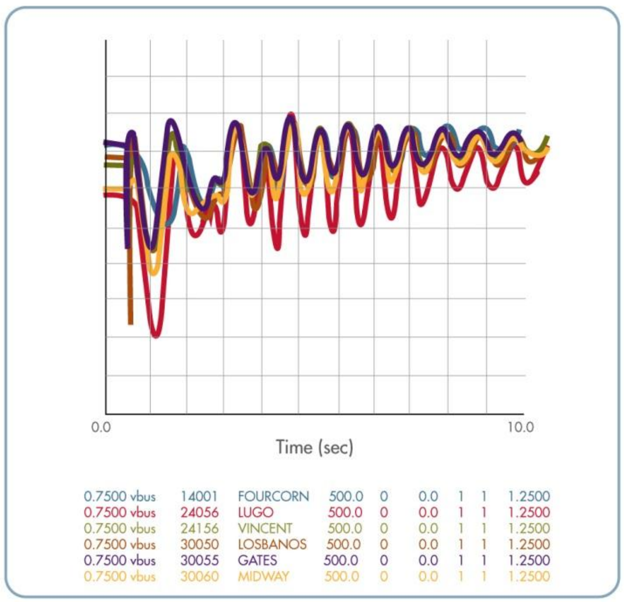


Figure 2.4.3-10. Frequency on major transmission buses, southern island

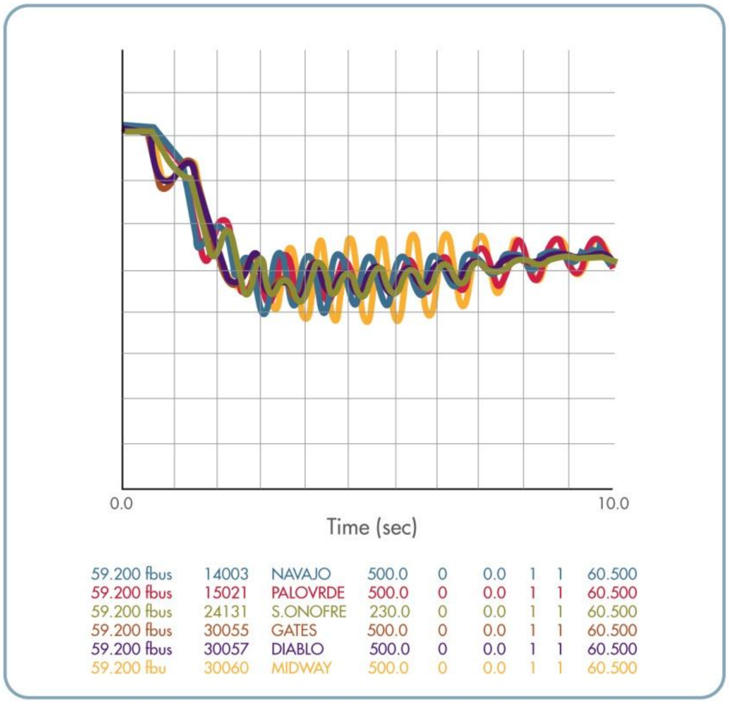
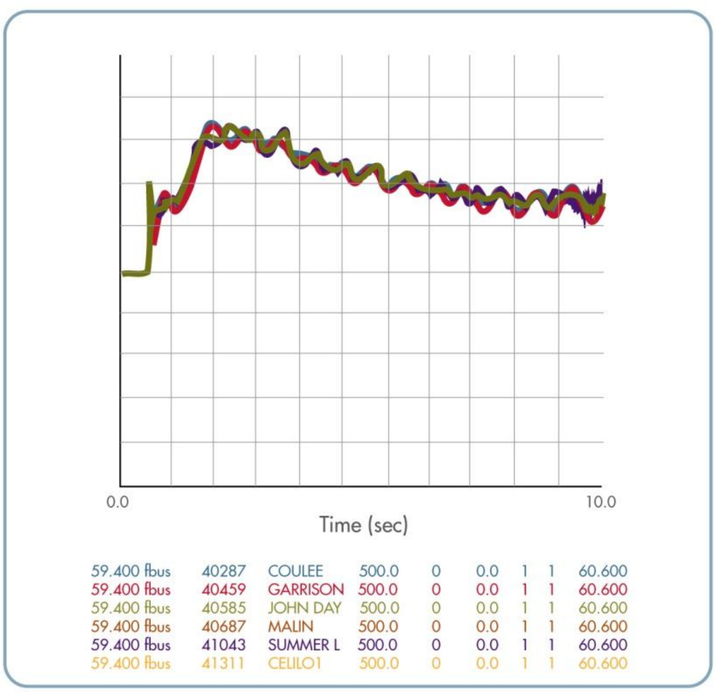


Figure 2.4.3-11. Frequency on 500 kV buses, northern island



A Path 26 outage was shown to be unstable and not having sufficient reactive margin. For these contingencies, more generation and load tripping will be required, especially in cases as extreme, as those studied.

2.4.4 Recommended Solutions

Following are proposed solutions for facilities not meeting thermal and voltage performance requirements.

2.4.4.1 Thermal Overload Mitigation

Borden-Gregg 230 kV Line

The Borden-Gregg 230 kV transmission line was identified as overloaded by approximately 1 percent in the 2021 summer peak scenario under normal conditions. Overload of this transmission line was identified previously in the *2010/2011 Transmission Plan* and in the *Transition Cluster Phase II Large Generation Interconnection* study. The proposed mitigation for this overload was to reconductor this line. The reconductoring was modeled in the *2011/2012 Transmission Plan* power flow cases. However, the Borden-Gregg 230kV line may still overload slightly under normal conditions if the Helms power plant and the new power plant that is proposed to be interconnected to the Gates 230 kV Substation are generating at full output, as was modeled in the 2021 summer peak case. The mitigation solution is either to reconductor the Borden-Gregg 230 kV line with a higher capacity conductor or to use congestion management (reduce Helms or new power plant generation) in case of overload on the Borden-Gregg 230 kV line.

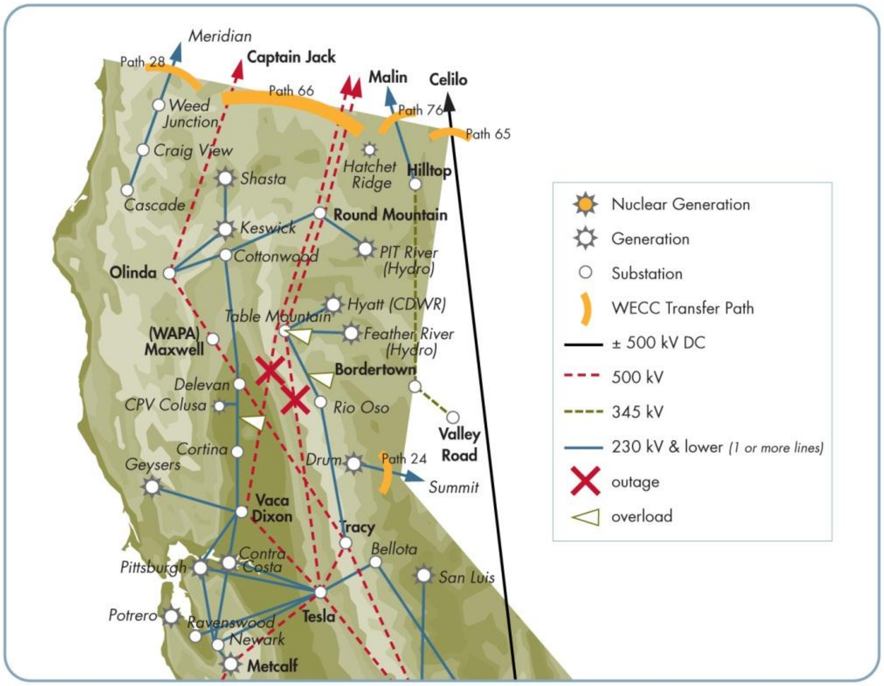
Weber-Tesla 230 kV Line

The studies showed that this transmission line may overload under summer peak normal conditions in 2021. This overload will be evaluated in next year's and future transmission plans. If the overload is confirmed, a transmission upgrade will be considered.

Table Mountain 500/230 kV Transformer

This transformer bank may overload under category C contingency conditions with a double outage of two 500 kV transmission lines south of Table Mountain: Table Mountain-Tesla and Table Mountain-Vaca Dixon during summer peak in 2016 and 2021 with high COI flow. Loading on the Table Mountain transformer with a South of Table Mountain 500 kV double line outage depends significantly on the RAS applied with this outage and on which generation units are tripped by this RAS. The existing RAS trips generation in both the northwest (up to 2,400 MW, depending on the COI flow) and at Feather River, as well as tripping irrigational pump load in Northern and Southern California. The generation and pump load tripping is needed to protect the Table Mountain 500 kV transformer as well as the Table Mountain-Rio Oso 230 kV line. These facilities are shown in figure 2.4.4.1-1. The ISO proposes to re-rate Table Mountian 500/230 kV bank by 2016, which currently does not have an emergency rating.

Figure 2.4.4.1-1 PG&E Bulk Transmission System Overload in the Table Mountain area



Delevan-Cortina 230 kV line

A slight overload (1 percent) on this transmission line was identified in the 2016 summer peak case with a double outage of 500 kV transmission lines south of Table Mountain (See figure 2.5.4.1-1). The ISO proposes to add Colusa generation to the South of Table Mountain double outage RAS, so that part of the Colusa generation would be dropped in case of Delevan-Cortina 230 kV line overload.

Panoche-Gates #1 and # 2 230 kV lines

These transmission lines may overload under off-peak conditions with high Path 15 flow for category B and category C contingencies. The studies of the 2016 summer off-peak case identified overload on these lines for a double outage of the Gates-Gregg and Gates-McCall 230 kV lines and for a single outage of the Los Banos 500/230 kV transformer. These lines are expected to overload even if all Helms pumps are tripped under a category C contingency and one pump is tripped with the category B contingency. (The case studied modeled two Helms units operating in pumping mode). One mitigation solution is to upgrade the Panoche-Gates 230 kV lines. A second solution is to develop additional SPS for the outages that caused the overload, such as tripping all Helms pumps for the Los Banos transformer outage or tripping load in the Fresno area for the Gates-Gregg and Gates-McCall 230 kV line outage in addition to tripping all Helms pumps. The ISO will work with PG&E to determine an optimal solution.

The post transient studies did not show any voltage concerns for any contingency if all applicable RAS and SPS are utilized. The transient stability studies did not identify any criteria violations. However, several small wind generators in the Tehachapi area that were constructed with the old technology (induction generators) — and that do not have low voltage ride-through capability — may trip off-line for the three-phase faults on adjacent substations (Midway 500 kV), or single-phase faults with delayed clearing on the Los Banos or Gates 500 kV substations.

2.4.5 Key Conclusions

The ISO study assessment, of the northern bulk system yielded the following conclusions:

- Two overloads are expected under normal summer peak conditions in 2021.
- One overload caused by one multiple contingency under summer peak conditions is expected in 2021 and two are expected in 2016.
- Two overloads caused by one single and one double contingency under summer off-peak conditions are expected in 2016.

The overloads under normal system conditions were identified from the long-term studies (i.e., 2021 time frame). Although conceptual mitigation plans have been proposed to address these issues, there is adequate time to refine the appropriate scope and timing of the proposed upgrades. Meanwhile, these facilities need to be monitored closely or require more work and coordination with PTO and neighboring entities in the development of the mitigation plans. Two of the overloaded facilities (Panoche-Gates #1 and #2 230 kV lines) were also identified from the local area assessment. The ISO-proposed solution to mitigate the identified reliability concerns are as follows:

- re-rate Table Mountain 500/230 kV transformer;
- add Colusa generation to the RAS for the 500 KV double outage south of Table Mountain; and
- reconductor Panoche-Gates #1 and #2 230 kV lines or develop additional SPS to mitigate overload on these lines. The ISO will work with PG&E on the final mitigation plan.

The ISO has received a project for the PG&E Bulk Transmission System in the Project Request Window – Midway-Gregg-Tesla 500 kV Line, that was not in response to a specific identified reliability concern. This project was proposed as needed to continue to provide reliable supply to the Greater Fresno Area. In addition the project as proposed may also:

- allow operating of three units in the pumping mode at Helms Pump Storage Power Plant; and
- aid in the interconnection and integration of renewable resources to supply California consumers.

The needs within the area are multi-faceted with a variety of potential benefits associated with modifications to the bulk system in the area. The potential benefits of the project may be either one of or a combination of the following.

- Reliability;
- Economic;
- Policy; and/or
- Renewable integration.

With this, a comprehensive study plan will be developed to assess the inter-related needs and benefits of the bulk system modifications as indicated in the request window project or other alternatives, and will be included as a part of the 2012/2013 transmission planning cycle. This assessment will consider the generation portfolios that will be used for the 2012/2013 transmission planning and will include a comprehensive analysis associated with renewable integration.

2.5 PG&E Local Areas Assessment

In addition to the PG&E Bulk Area study, studies were performed for its eight local areas. With the assessments for the local areas, TPL-004 studies were not analyzed as the most severe contingencies in the PG&E area. They were analyzed in the PG&E Bulk Transmission System assessment. These are discussed below.

2.5.1 Humboldt Area

2.5.1.1 Area Description

The Humboldt area covers approximately 3,000 square miles in the northwestern corner of PG&E's service territory. Some of the larger cities that are served in this area include Eureka, Arcata, Garberville and Fortuna. The highlighted area in the adjacent figure provides an approximate geographical location of the Humboldt area.

Humboldt's electric transmission system is composed of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant and local qualifying facilities generation units. Additional electric supply is provided by transmission imports via two 100 mile, 115 kV circuits from the Cottonwood substation east of this area and one 80 mile 60 kV circuit from the Mendocino substation south of this area.

Historically, the Humboldt area experiences its highest demand during the winter season. For the 2011-2012 transmission planning studies, a summer peak and winter peak assessment was performed. For the summer peak assessment, a simultaneous area load of 188 MW and 207 MW in the 2016 and 2021 time frames was assumed. For the winter peak assessment, a simultaneous area load of 209 MW and 224 MW in the 2016 and 2021 time frames were assumed. An annual load growth for both summer and winter peak of approximately 3 MW per year was also assumed.

2.5.1.2 Area-Specific Assumptions and System Conditions

The Humboldt area study was performed in accordance with the general study assumptions and methodology described in section 2.3. The ISO-secured website lists the contingencies that were evaluated as a part of this assessment. Specific assumptions and methodology applied to the Humboldt area study are provided below. Finally, because Humboldt is the only winter peaking area within PG&E, a detailed assessment was performed for both winter and summer peak conditions for the years 2012 through 2016, and 2021.

Generation

Generation resources in the Humboldt area consist of market, qualifying facilities and self-generating units. The largest resource in the area is the 166 MW Humboldt Bay Power Plant. The Humboldt Bay Power Plant was re-powered and started commercial operation in the summer of 2010. It replaced the Humboldt power plant, which was retired in November 2010. In addition, the 12 MW *Blue Lake Power Biomass Project* was placed into commercial operation on August 27, 2010. Table 2.5.1-1 lists generation plants in the Humboldt area.

Table 2.5.1-1: Generation plants in the Humboldt area

Generation Plant	Max. Capacity
Humboldt Bay	166
Kekawaka	4.9
Pacific Lumber	32.5
LP Samoa	25
Fairhaven	17.3
Blue Lake	12
Generation Total	258

The studies assumed that a new 50 MW wind generation project will be added in 2016. This project is planned to interconnect to the Rio Dell Junction 60 kV Substation.

Load Forecast

Loads within the Humboldt area reflect a coincident peak load for 1-in-10-year heat wave conditions of each study year. Tables 2.5.1-2 and 2.5.1-3 summarize loads modeled in the studies for the Humboldt area.

Table 2.5.1-2: Load forecasts modeled in Humboldt area assessment, summer peak

1- in- 10 Year Heat Wave Non-simultaneous Load Forecast						
Summer Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
HUMBOLDT	175	178	180	184	188	207

Table 2.5.1-3: Load forecasts modeled in Humboldt area assessment, winter peak

Non-simultaneous Load Forecast						
Winter Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
HUMBOLDT	197	200	204	206	209	224

2.5.1.3 Study Results and Discussions

Following is a summary of the study results of facilities in the Humboldt area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one facility (Bridgeville-Fruit Land section of the Bridgeville-Garberville 60 kV transmission line) was identified with thermal overload in 2021 under normal conditions with all facilities in service. No facilities were identified with thermal overloads in any other study years. For the winter peak cases, no facilities were identified with thermal overloads under the category A performance requirement. For the summer peak cases, three 60 kV buses were identified with low voltage concerns under the category A performance requirement in 2012. No buses were identified with low voltage concerns in any other study years. For the winter peak cases, no facilities were identified with low voltage concerns under normal system conditions.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1/G-1)

For the summer peak cases, six facilities were identified with thermal overloads. These facilities included three sections of the same transmission line. Ten 60 kV buses were identified with low voltage concerns with single facility outages in 2012, and no facilities were identified with voltage concerns for category B contingencies in other study years. Twenty buses had high voltage deviation concerns with category B contingencies. Thirteen of these were identified for a single transmission line or transformer outage, and seven were identified for an outage of one generator and one transmission line. For the buses with high voltage deviations with single facility outages, such a concern was identified only for the year 2012.

For the winter peak cases, seven facilities were identified with thermal overloads. These included three sections of the same transmission line, and two sections of another transmission line. Eleven 60 kV buses were identified with low voltage concerns with single facility outages in 2012. No facilities were identified with voltage concerns for category B contingencies in other study years. Twenty-three buses were identified with voltage deviation concerns with category B contingencies. Fifteen of these were identified for a single transmission line or transformer outage, and eight were identified for an outage of one generator and one transmission line.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, 15 facilities were identified with thermal overloads. Nineteen buses were identified with low voltage concerns, and 21 buses were identified with voltage deviation concerns under the category C performance requirement. Out of 15 facilities that had thermal overloads, 12 were separate sections of four transmission lines. Four of these 15 facilities also may overload for category B contingencies, and one may also overload for category A. Out of 19 buses with low voltage concerns, nine also have voltage concerns with category B contingencies, including three with low voltages under normal conditions. Out of 21 buses with voltage deviation concerns, 18 also had voltage deviation concerns for category B contingencies.

For the winter peak cases, 12 facilities were identified with thermal overloads. Twenty buses were identified with low voltage concerns under the category C performance requirement. In addition, voltage deviation concerns were also identified on 21 buses. Out of 12 facilities that had thermal overloads, seven were separate sections of the three transmission lines. Voltage concerns included one diverged case. Out of 20 buses with low voltage concerns, ten also had voltage concerns with category B contingencies, including one with low voltage under normal conditions. The same 21 buses that had voltage deviation concerns also had voltage deviation concerns for category B contingencies.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and winter peak conditions along with the corresponding proposed solutions.

Two of the buses (Laytonville 60 kV and Covelo 60 kV) identified with low voltage and voltage deviation concerns for category B and C contingencies are located in the North Coast area, but they are impacted by the Humboldt area contingencies.

2.5.1.4 Recommended Solutions

Based on this year's reliability assessment for the Humboldt area, the ISO identified needed solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories B and C contingency conditions.

2.5.1.4.1 Thermal Overload Mitigations

Humboldt Bay-Humboldt 60 kV #1 Line

The Humboldt Bay-Humboldt 60 kV #1 transmission line consists of two sections: Humboldt-Humboldt Junction and Humboldt Junction-Humboldt Bay. This line is paralleled by the Humboldt Bay-Humboldt 60 kV line #2 and the Humboldt-Eureka, Eureka-Humboldt Bay 60 kV lines. The summer analysis results indicated that the Humboldt-Humboldt Junction portion of the line would exceed its emergency rating for both category B and category C contingencies of the parallel transmission lines and for category C contingencies of any two transmission lines in the Cottonwood-Bridgeville-Humboldt area starting in 2016 for category B and 2012 for category C. The Humboldt Junction-Humboldt Bay portion of the line has a higher rating and will exceed its emergency rating only for category C contingencies of the parallel transmission lines between Humboldt and Humboldt Bay starting in 2012.

The winter analysis indicated that the Humboldt-Humboldt Junction portion of the line would exceed its emergency rating for category C contingencies of the parallel transmission lines: the Humboldt Bay-Humboldt 60 kV line #2 and the Eureka-Humboldt Bay starting in 2012. Line overloads for category B contingencies of either of these parallel transmission lines were not found in this analysis. This is because higher transmission line ratings were assumed for the winter conditions. The Humboldt

Junction-Humboldt Bay section of the line is not expected to overload under winter conditions until 2016 under category C contingency conditions.

Power flow studies modeled the new Humboldt Bay power plant generating at full output. An overload on the Humboldt Bay-Humboldt 60 kV #1 transmission line was caused by high output of the six generation units of the Humboldt Bay power plant connected to the 60 kV bus. A new wind generation project that is planned to interconnect to the Rio Dell Junction 60 kV Substation will significantly increase the observed overload.

The Humboldt Bay-Humboldt 60 kV line #1 will be upgraded by October 2014 as a part of PG&E's *Infrastructure Replacement Project*, which is a maintenance project that does not require ISO approval. If the line is not reconductored, an SPS to trip some of the Humboldt Bay generation will be needed by 2016. The ISO will follow-up with PG&E on the maintenance project of the line reconductoring and/or the SPS installation.

In the short-term, the ISO proposes to address these thermal overload concerns by applying the PG&E Action Plan to reduce generation from the Humboldt Bay 60 kV power plant following the first contingency. This action plan was approved by the ISO. Under the worst scenario for the category B overload, it is sufficient to trip one unit or reduce generation by 15 MW in 2021 if the line is not upgraded. For the category C overload, it is sufficient to trip 4 units or reduce generation by 55 MW in 2021 if the line is not upgraded.

Humboldt Bay-Humboldt 60 kV #2 Line

An overload of this line is expected during summer peak under category C contingencies with an outage of any two of the parallel transmission lines (i.e., Humboldt Bay-Humboldt 60 kV line #1, the Humboldt-Eureka-Humboldt Bay 60 kV line and Humboldt Bay-Bridgeville 60 kV lines) starting from 2012. The same condition exists for winter peak under category C contingencies starting from 2016. A new wind generation project that is expected to connect to the Rio Dell Junction 60 kV Substation significantly impacted the observed overload.

Reconductoring of the Humboldt Bay-Humboldt 60 kV line #2 was identified in the LGIA for this generation project. It is planned to be implemented when this project comes on line, which is presently expected for December 2013. The project was modeled as dispatched in the 2016 and 2021 study cases.

Prior to the line reconductoring, an operating procedure to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after the first contingency will mitigate this overload. The mitigation is required by summer 2012. The ISO proposes addressing these category C concerns by utilizing PG&E's existing action plan. This action plan will reduce the Humboldt Bay power plant generation after the first contingency and thus will mitigate the category C overloads.

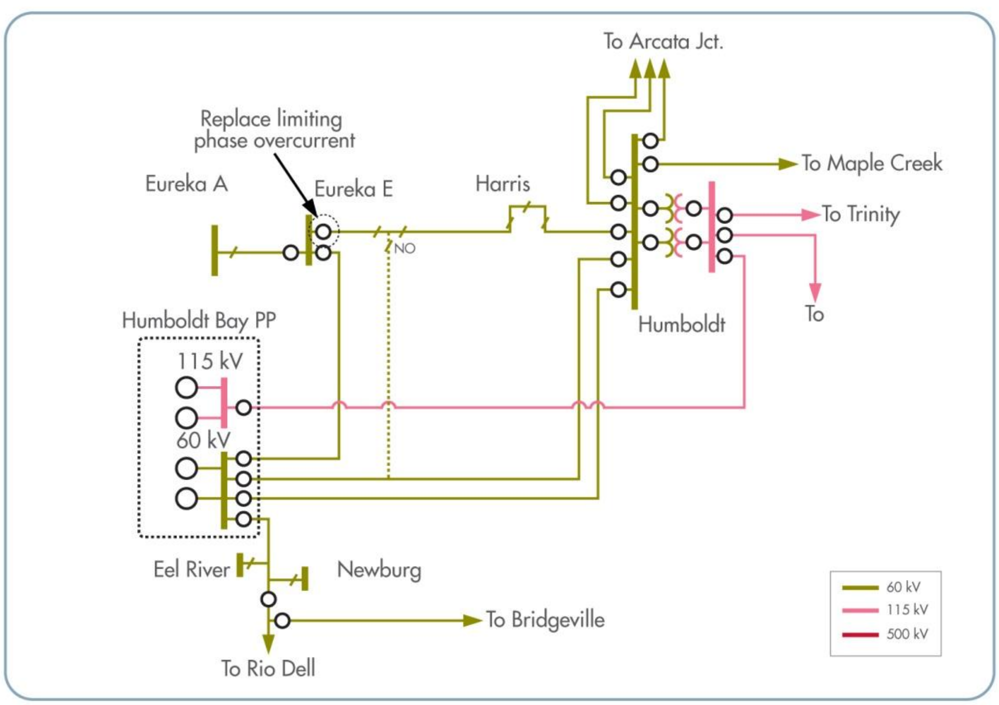
Humboldt-Eureka 60 kV #1 Line

The Humboldt-Eureka 60 kV line #1 consists of three sections: Humboldt-Harris, Harris-Harris Tap and Harris Tap-Eureka. The sections of this transmission line between Harris-Harris Tap and Harris Tap-Eureka will exceed their emergency ratings for certain category C contingencies during summer peak starting in 2012. The section between Harris Tap and Eureka may overload under winter peak conditions for a category B contingency (Humboldt Bay-Eureka 60 kV line) starting in 2013 and for category C contingencies starting in 2012. This section is limited by the terminal equipment at Eureka Substation. Replacement of the terminal equipment will mitigate overload of the Harris Tap-Eureka section for category B contingency.

The loading level of the Humboldt-Eureka 60 kV line will be impacted by the new wind generation project that has been planned to interconnect to the Rio Dell 60 kV Substation. Reconductoring of the Harris-Harris Tap-Eureka section of this line was included in this project's LGIA. Prior to the line reconductoring, the ISO proposes addressing the category C concerns by utilizing PG&E's existing action plan. This action plan will reduce the Humboldt Bay power plant generation after the first contingency and will mitigate the category C overloads. Category B concerns should be mitigated by replacing limiting equipment at the Eureka Substation in 2012.

The ISO received a project in the Request Window to mitigate this reliability concern — *Humboldt-Eureka 60 kV Capacity Increase.* The project scope is to replace protection limiting equipment of the Humboldt-Eureka 60 kV transmission line between the Harris and Eureka substations with a rating of at least 475 A to utilize full conductor rating. This project is consistent with the ISO proposal. The proposed in-service date is May 2015, and the estimated cost is between $1M and $3M. The project diagram is shown in figure 2.5.1-1 below. After evaluating all the alternatives, the ISO considers this project to be a cost-effective solution to the identified reliability concern. However, the ISO recommends replacing the limiting equipment sooner than the proposed date because the category C overload is an existing problem.

Figure 2.5.1-1: Humboldt-Eureka 60 kV Capacity Increase Project



Humboldt Bay-Eureka 60 kV #1 Line

This transmission line will exceed its emergency rating for certain category B contingencies (such as Humboldt Bay-Humboldt 60 kV line #2 alone or together with any one generation unit in the area) during the winter peak starting in 2016. It will also exceed its emergency rating under category C contingencies beginning in 2012, both in summer and winter. The Humboldt Bay-Eureka 60 kV line will be reconductored as part of the LGIA for the renewable generation project that will interconnect to the Rio Dell Jct 60 kV Substation (current Commercial Operational Date is December 2013). The line reconductoring will mitigate all overloads.

Prior to the line reconductoring, an operating procedure to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after the first contingency will mitigate this overload for category C conditions. This procedure is a part of the existing PG&E action plan.

Humboldt Bay-Rio Dell Junction 60 kV #1 Line

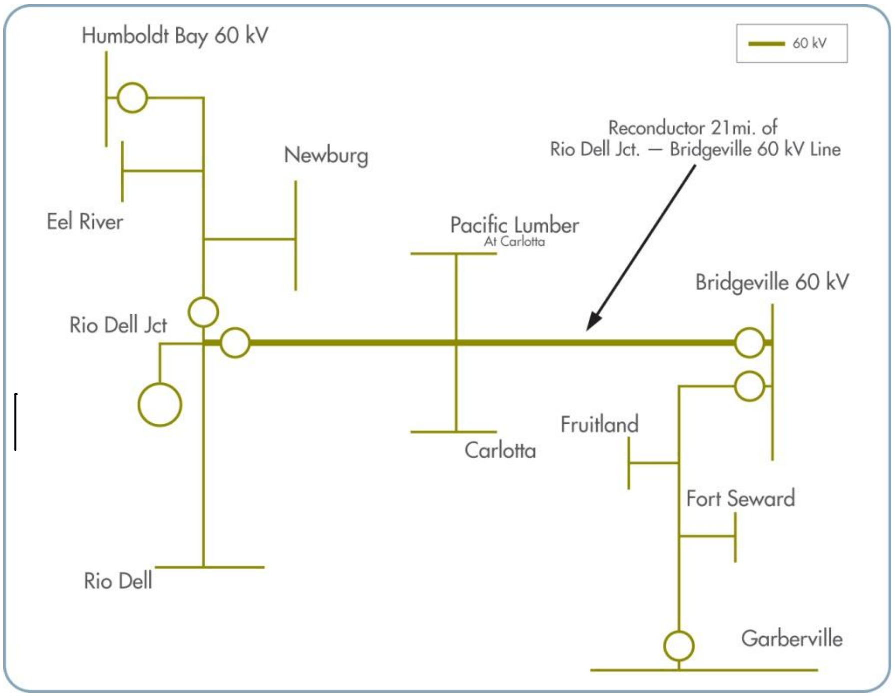
This transmission line consists of three sections: Humboldt Bay-Eel River, Eel River-Newburg and Newburg-Rio Dell Junction. The section between Newburg and Rio Dell Jct will exceed its emergency rating for a category B (Rio Dell Jct-Bridgeville 60 kV line) and several category C contingencies during both summer and winter. This line loading is impacted by the new renewable generation project that will interconnect to the Rio Dell Jct 60 kV Substation, and the category B overload is not expected until this project interconnects. Reconductoring of this transmission line section, as well as the rest of the transmission line (Humboldt Bay-Eel River and Eel River-Newburg sections) that may overload with category C contingencies are part of this project's LGIA. Also, a PG&E maintenance project to upgrade the Humboldt 60 kV bus to a breaker-and–a-half configuration currently scheduled for May 2014 will mitigate the overload with an outage of the Humboldt 60 kV bus (category C). Prior to the upgrade of the Humboldt 60 kV bus, the PG&E action plan to reduce the Humboldt Bay power plant generation will mitigate the overload in case of the Humboldt 60 kV bus outage.

Rio Dell Junction-Bridgeville 60 kV #1 Line

All three sections of this transmission line will exceed their emergency rating for certain category B (Humboldt-Bridgeville 115 kV line or Rio Dell Jct-Newburg 60 kV line) and category C contingencies during summer peak starting in 2016 for category B and 2012 for category C. They will also exceed their emergency rating during winter peak starting in 2016 for both category B and C contingencies. The mitigation solution will be an SPS to trip a new wind power plant that is expected to interconnect to the Rio Dell Jct. 60 kV Substation. It will mitigate the category B and some of the category C overloads. The PG&E maintenance project to upgrade the Humboldt 60 kV bus to a breaker-and–a-half configuration will mitigate the overload that may occur with an outage of this bus both in summer and in winter. Category C overloads that may occur prior to the new wind generation project coming into service (estimated in December 2013) will be mitigated by the existing PG&E action plan to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after the first contingency.

The ISO received a project in the Request Window to mitigate this reliability concern — *Rio Dell Jct-Bridgeville 60 kV Line Reconductoring.* The project scope is to reconductor 21 miles of the Rio Dell Jct-Bridgeville 60 kV line with a conductor rated for at least 742 A emergency rating. The proposed in-service date is May 2016, and the estimated cost is between $17M and $25M. The project diagram is shown in figure 2.5.1-2 below.

Figure 2.5.1-2: Rio Dell Jct-Bridgeville 60 kV Line Reconductoring Project



After reviewing this project submittal, the ISO concluded that the line reconductoring may be replaced by an SPS that would trip the new renewable generation project for overload at a significantly lower cost than reconductoring, and therefore this project is not needed.

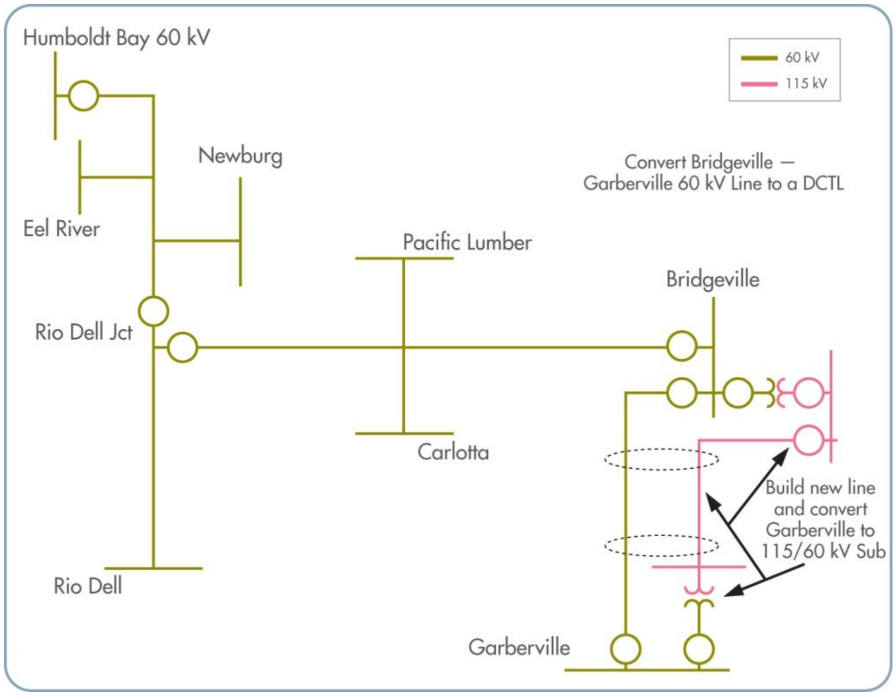
Bridgeville-Garberville 60 kV #1 Line

The section of this line between Bridgeville and Fruitland may overload under normal conditions in 2021 summer peak. This section may also overload during summer peak with category C contingencies starting in 2012. The sections between Fruitland and Fort Seward and Fort Seward and Garberville may overload during summer peak with category C contingencies starting in 2013.

The ISO-proposed an SPS to trip the new wind power plant that will be interconnected to the Rio Dell Junction 60 kV Substation. Additionally, the PG&E maintenance project to upgrade the Humboldt 60 kV bus will mitigate the category C overloads. However, the permanent solution to the category A and C overload and category B and C voltage problems will be a transmission upgrade.

The ISO received a project in the Request Window to mitigate this reliability concern — *New Bridgeville-Garberville No. 2 115 kV Line.* The project will also resolve voltage concerns in the Bridgeville area. The scope of the project is to construct a new 36-mile-long 115 kV line between Bridgeville and Garberville substations as a Double-Circuit Tower line with the existing 60 kV Bridgeville-Garberville line. This project will also require construction of a 115 kV bus at Garberville Substation and installation of a 115/60 kV transformer. The project diagram is shown in figure 2.5.1-3 below.

Figure 2.5.1-3: New Bridgeville-Garberville #2 115 kV Line



Alternatives to the construction of the new Bridgeville-Garberville 115 kV line were considered. Reconductoring of the existing Bridgeville-Garberville 60 kV line was estimated by PG&E as between $40M and $47M. Reconductoring of the existing line does not solve voltage problems that were observed with the Category B and C contingencies. To mitigate the voltage concerns, installation of at least 20 MVAR of reactive support would be required. This reactive support would need to be dynamic (SVC) because shunt capacitors would not mitigate voltage flicker, would cause unacceptably high voltage under normal conditions and would not prevent voltage collapse with Category C contingencies. In addition, an SPS to trip load for Category C contingencies would be required. The cost of a 20 MVAR SVC was estimated at around $19-$22M and the cost of an SPS between $6M and $12M. The total cost of reconductoring plus additional reactive support and SPS would be higher than the cost of the new 115 kV line that was estimated to be between $55M and 65M. In addition, long 60 kV lines make this area susceptible to voltage collapse in case of double contingencies. The additional 115 kV line will improve voltage stability of the transmission system in the Humboldt and North Coast areas.

After reviewing this project and considering all the alternatives, the ISO concluded that building the Bridgeville-Garberville 115 kV line is an optimal solution to the identified reliability concerns. The project's in-service date is estimated as May 2018, and the estimated cost is between $55M and $65M.

Essex Junction-Arcata-Fairhaven 60 kV #1 Line

The section of this transmission line between Janes Creek Tap and Arcata Tap is expected to exceed its emergency rating under category B conditions during summer peak in approximately 2018. The mitigation solution will be the line upgrade planned at about that time frame. The ISO has received a project in the Request Window — *Essex Jct – Arcata-Fairhaven 60 kV Line Reconductoring.* This was proposed as a conceptual project since the need for upgrade is not expected until 2018.

Bridgeville 115/60 kV #1 Transformer

This transformer will exceed its emergency rating for a category B contingency (Humboldt Bay-Rio Dell Jct 60 kV line) in winter starting in 2012 and for several category C contingencies in both summer and winter starting in 2012. PG&E plans a maintenance project by December 2012 to replace the Bridgeville transformer with a new transformer that will have a higher rating. The new transformer will have 90 MVA rating that will be sufficient to mitigate the overloads. The ISO will follow-up with PG&E on the Bridgeville transformer replacement. In the interim, an existing operating procedure to open Circuit Breaker 42 at the Bridgeville 60 kV Substation after the first contingency will mitigate the overload for category C contingencies. Additionally, dispatching all Pacific Lumber generation under winter peak conditions will mitigate the overload with the Humboldt Bay-Rio Dell Junction outage.

Humboldt 115/60 kV Transformer Banks #1 and #2

These transformers will exceed their emergency rating for certain category C contingencies during winter peak starting in 2012. Replacement of these transformers with higher rated ones was approved by the ISO in the *2009 California ISO Transmission Plan* and the planned in-service date is March 2013 for the first bank and March 2014 for the second. The transformer replacement will mitigate the overloads. In the interim, tripping some of the Humboldt Bay power plant 115 kV generation will be required. The ISO will follow-up with PG&E on developing an SPS or an operating procedure that is needed by winter of 2012.

2.5.1.4.2 Voltage Concern Mitigation

In the *2009 California ISO Transmission Plan*, the ISO approved installation of reactive support at the Maple Creek and Garberville 60 kV substations with in-service dates of May 2011. Because of permitting and construction issues, the Maple Creek Reactive Support Project is postponed to December 2015 and the Garberville Reactive Support Project is postponed to June 2013. These projects were modeled starting from the 2013 cases, since at the time of the studies, the in-service dates for these projects were not finalized. The studies identified low voltages and voltage deviation concerns in the Maple Creek and Garberville areas for category B and C contingencies in both summer and winter prior to the installation of this reactive support. In addition, low voltages may be observed at the Garberville, Fort Seward and Kekawaka substations under summer peak normal conditions until the reactive support at Garberville is installed. As an interim solution, the ISO proposes to dispatch Kekawaka generation during peak load conditions, which will mitigate low voltages and voltage deviations with category B contingencies in the Garberville area. PG&E has an Action Plan to mitigate low voltages in the Maple Creek and Garberville areas prior to installation of the reactive support. This plan consists of increasing regulator settings on the Mendocino 115/60 kV transformers, and manually inserting shunt capacitors at Mendocino and Fort Bragg, if needed. In the Maple Creek area, the automatic load restore feature on Maple Creek is disabled during peak demand periods. This action would result in a local service interruption in the event of an outage until the service could be manually restored.

Low voltages and large voltage deviations were observed for an outage of the Bridgeville 115/60 kV transformer in summer 2021 and winter 2016. The category C outages involved this transformer bank in all the cases studied — both in summer and winter. An outage of the Bridgeville 115/60 kV transformer and Rio Dell Junction-Bridgeville 60 kV line did not converge because of insufficient reactive margin. To mitigate these concerns, PG&E's existing operating procedure to open Circuit Breaker 42 at the Bridgeville 60 kV Substation needs to be applied. Opening this circuit breaker will sectionalize the 60 kV system between Bridgeville and Garberville so that the Fruitland and Fort Seward substations will be served from the North Coast area through Garberville. No load shedding is expected with this operating procedure after the first contingency; however some local load shedding (at Carlotta Substation) may occur with the second contingency. With this procedure, the voltage concerns were mitigated and the diverged cases were resolved. A permanent solution to both the voltage concerns in the Bridgeville-Garberville area and the overload of the Bridgeville-Garberville 60 kV transmission line will be construction of the new Bridgeville-Garberville 115 kV line.

Another contingency that caused voltage concerns was an outage of the Arcata-Humboldt 60 kV line either together with the Blue Lake generation (category B) or with the Humboldt #1 60 kV line (category C). This is expected to cause low voltages and voltage deviation concerns in the most northern part of Humboldt County (Trinidad, Blue Lagoon, Orick substations). The mitigation solution is to install reactive support at the Orick 60 kV Substation. The ISO has received a project in the Request Window that will install such reactive support — *Northern Humboldt Reactive Support*. This project proposes installing a shunt capacitor at the Orick 60 kV Substation by May 2021. The project was proposed as conceptual, since the need was not identified until 2021. The ISO considers that reactive support in this area is needed sooner, since the voltage deviation concern with an outage of the Humboldt-Arcata 60 kV line when the Blue Lake generator is out of service may arise as soon as winter 2012.

The studies also showed voltage deviation concerns at the Arcata 60 kV bus for a category B contingency in winter 2021. If this concern is confirmed in the 2012-2013 Transmission Plan studies, reactive support at the Arcata Substation will be considered.

2.5.1.5 Key Conclusions

The ISO study of the Humboldt area yielded the following conclusions:

- One overload would occur under normal conditions in 2021.
- Six overloads would occur for five category B contingencies under summer peak conditions starting in 2016. Seven overloads would occur for category B contingencies under winter peak conditions. This includes overloads on the Bridgeville 115/60 kV transformer bank prior to its replacement and overloads

on six transmission lines starting in 2013 for one line and in 2016 for five others.

- Low voltages and large voltage deviations would occur for three category B contingencies in 2012 prior to installation of reactive support on the Maple Creek and Garberville 60 kV substations. During summer peak, both low voltage and voltage deviation concerns are expected on four substations in the Maple Creek area and six substations in the Garberville area There are also voltage deviation concerns on one other substation in the Maple Creek area and two other substations in the Garberville area. During winter peak, low voltage and voltage deviation concerns are expected on five substations in the Maple Creek area and six substations in the Garberville area, with voltage deviation concerns on three other substations in the Garberville area. The existing PG&E Action Plan will mitigate these voltage concerns.
- After installation of the Maple Creek and Garberville reactive support, no low voltages are expected for category B contingencies, but voltage deviation concerns may start in these areas in approximately 2021.
- Voltage deviation concerns were identified on seven 60 kV buses (in summer) and nine 60 kV buses (in winter) for a category B contingency at the Blue Lake Power Plant and Humboldt-Arcata 60 kV line.
- In addition to the facilities overloaded for category B contingencies, 11 transmission facilities may become overloaded with various multiple contingencies starting in summer 2012 and five facilities starting in winter 2012.
- Ten buses had low voltages for category C contingencies in addition to the buses with low voltages for category B contingencies both in summer and in winter. In addition to voltage deviation concerns for category B contingencies, three additional buses had voltage deviation concerns for category C contingencies in summer. In winter, all the buses with category C voltage deviation concerns also had these concerns for category B contingencies.

The identified overloads will be addressed as follows:

- Five transmission lines will be reconductored with the renewable generation project interconnecting to the Rio Dell 60 kV Substation.
- For one category B overload (three sections of the Rio Dell-Bridgeville 60 kV line), it is proposed to install an SPS to trip this generation project with the overload.
- Overload on the Humboldt-Eureka 60 kV line is proposed to be mitigated by replacing the limiting terminal equipment.
- Overload on the Essex Jct-Arcata-Fairhaven 60 kV line is proposed to be mitigated by upgrading the overloaded section at the time the overload is expected (after 2016).
- Overload on the Bridgeville-Garberville 60 kV line that is expected under normal conditions in 2021 and under multiple category C contingencies starting in 2012 is proposed to be mitigated by a transmission upgrade that would

construct a new Bridgeville-Garberville 115 kV transmission line. This upgrade will also solve voltage concerns in the Bridgeville area.

- It is proposed to use operating procedures and the SPS described above for category C contingencies.
- The low voltages and voltage deviation concerns in the most northern part of Humboldt County are proposed to be mitigated by installing reactive support at the Orick Substation around 2021 and by applying an SPS and operating procedures for category C contingencies.

The ISO received five new transmission projects in the Humboldt area through the 2011-2012 Transmission Plan Request Window, two of which were proposed as conceptual. The ISO determined that the project — *Humboldt-Eureka 60 kV Capacity Increase* was consistent with the ISO's proposed mitigation solutions and is needed to mitigate identified reliability concerns. The ISO also determined that the project *New Bridgeville - Garberville No. 2 115 kV Line* is needed to mitigate identified reliability concerns.

The ISO recommends installing an SPS to trip the new renewable generation project in lieu of PG&E's proposed project, *Rio Dell Junction-Bridgeville 60 kV Line Reconductoring*. This project was determined not to be needed.

Two projects, *Northern Humboldt Reactive Support* and *Essex Junction-Arcata-Fairhaven 60 kV Line Reconductoring* were proposed as conceptual, since the need for them is not expected until after 2016, and the project sponsors did not ask for ISO's approval of these projects.

2.5.2 North Coast and North Bay Areas

2.5.2.1 Area Description

The highlighted areas in the adjacent figure provide an approximate geographical location of the North Coast and North Bay areas.

The North Coast area covers approximately 10,000 square miles north of the Bay Area and south of the Humboldt area along the northwest coast of California. It has a population of approximately 850,000 in Sonoma, Mendocino, Lake and a portion of

Marin counties and extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions. Some substations in the North Coast area are summer peaking, and some are winter peaking. For the summer peak assessment, a simultaneous area load of 831 MW and 913 MW in the 2016 and 2021 time frames was assumed. For the winter peak assessment, a simultaneous area load of 674 MW and 735 MW in the 2016 and 2021 time frames was assumed. An annual load growth for summer peak of approximately 16 MW and winter peak of approximately 12 MW per year was also assumed. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The North Coast area is connected to the Humboldt area by the Bridgeville-Garberville-Laytonville 60 kV lines. It is connected to the North Bay by the 230 kV and 60 kV lines between Lakeville and Ignacio. And, it is connected to the East Bay by 230 kV lines between Lakeville and Vaca Dixon and 115 kV lines between Eagle Rock, Mendocino and Cortina.

North Bay encompasses the area just north of San Francisco. This transmission system serves the counties of Marin, Napa and portions of Solano and Sonoma Counties.

Some of the larger cities that are served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is composed of 60, 115 and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento and the Bay Area. For the summer peak assessment, a simultaneous area load of 880 MW and 935 MW in the 2016 and 2021 time frames was assumed. For the winter peak assessment, a simultaneous area load of 774 MW and 814 MW in the 2016 and 2021 time frames was assumed. An annual load growth for summer peak of approximately 11 MW and for winter peak of approximately 9 MW per year was also assumed. Like the North Coast, the North Bay area has both summer peaking and winter peaking substations. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

2.5.2.2 Area-Specific Assumptions and System Conditions

The North Coast and North Bay area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO's secured website lists the contingencies that were performed as part of this assessment. Specific assumptions and methodology that were applied to the North Coast and North Bay area studies are provided below. Finally, since the North Coast and North Bay areas have both summer peaking and winter peaking substations, a detailed assessment was performed for both winter and summer peak conditions for the years 2012-2016 and 2021.

Generation

Generation resources in the North Coast and North Bay areas consist of market, qualifying facilities and self-generating units. Table 2.5.2-1 lists generating plants in the North Coast and North Bay areas.

Table 2.5.2-1: Generator Plants in North Coast and North Bay areas

Plant Name	Max Capacity (MW)
Santa Fe	160
Bear Canyon	20
Westford Flat	30
Western Geo	38
Geysers 5	53
Geysers 6	53
Geysers 7	53
Geysers 8	53
Geysers 11	106
Geysers 12	106
Geysers 13	133
Geysers 14	109
Geysers 16	118
Bottle Rock	55
Geysers 17	118
Geysers 18	118
Geysers 20	118
SMUD Geo	72
Potter Valley	11
Geo Energy	20
Indian Valley	3
Sonoma Landfill	6
Exxon	54
Monticello	12
Generation Total	**1,619**

The studies also modeled two future renewable generation projects. A new 10 MW biomass generation project was assumed to be on line in 2016 interconnected to the Lakeville #2 (Petaluma-Lakeville) 60 kV line. The second project, 35 MW geothermal plant was modeled to be interconnected to the Geysers #3-Cloverdale 115 kV line. It was also assumed to be on line in 2016.

Load Forecast

Loads within the North Coast and North Bay areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each study year. Tables 2.5.2-2 and 2.5.2-3 summarize the substation loads assumed in the studies for North Coast and North Bay areas under summer and winter peak conditions.

Table 2.5.2-2: Load forecasts modeled in North Coast and North Bay area assessments, summer peak

1- in- 10 Year Heat Wave Non-simultaneous Load Forecast						
Summer Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
NORTH COAST	780	793	803	817	831	913
NORTH BAY	842	856	863	872	880	935

Table 2.5.2-3: Load forecasts modeled in North Coast and North Bay area assessments, winter peak

Non-simultaneous Load Forecast						
Winter Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
NORTH COAST	633	642	653	662	674	735
NORTH BAY	738	749	758	765	774	814

2.5.2.3 Study Results and Discussion

A summary of the study results of facilities in the North Coast and North Bay area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance Under Normal Conditions

For the summer peak cases, no facilities in the North Coast and North Bay areas were identified with thermal overloads under the category A performance requirement. Overload of the Bridgeville-Garberville 60 kV transmission line, which connects the North Coast and Humboldt areas was already discussed in the Humboldt area section. There was one low voltage concern (Sausalito 60 kV bus) under normal system conditions in 2021.

For the winter peak cases, no facilities were identified with thermal overloads, and one facility (Sausalito 60 kV bus) was identified with low voltage concerns under the category A performance requirement.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1/G-1)

For the summer peak cases, ten facilities were identified with thermal overloads under the category B performance requirement. Out of these ten facilities, two were sections of the same transmission line. There were two low voltage concerns in 2021 (Sausalito and Greenbrae 60 kV substations), and 11 buses were identified as having voltage deviation concerns.

For the winter peak cases, five facilities were identified with thermal overloads, two facilities (Sausalito and Greenbrae 60 kV substations) were identified with low voltage concerns and 11 buses were identified with large voltage deviation under the category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases under the category C performance requirements, 35 facilities were identified with thermal overloads, including 26 separate sections of ten transmission lines. Twenty-one facilities were identified with low voltage concerns, and 26 facilities were identified with large voltage deviations.

For the winter peak cases, 15 facilities were identified with thermal overloads, including 12 separate sections of five transmission lines. Additionally, 12 facilities were identified with low voltage concerns, and 12 facilities were identified with large voltage deviations under the category C performance requirement.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and winter peak conditions along with the corresponding proposed solutions.

2.5.2.4 Recommended Solutions

Based on this year's reliability assessment results for the North Coast and North Bay areas, the ISO identified needed solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories B and C contingency conditions. These solutions are needed to maintain or enhance system reliability in a manner consistent with the applicable planning standards and the BPM for the transmission planning process. The proposed recommended solutions for the identified thermal overloads and voltage concerns are set forth below along with information about the expected in-service dates of the proposed mitigation.

2.5.2.4.1 Thermal Overload Mitigations

North Coast

Bridgeville-Garberville 60 kV #1 Line

This transmission line connects the Humboldt and North Coast areas. One of its sections may overload under normal conditions in approximately 2021. Additionally, all three sections of the line are expected to overload with various category C contingencies, which may occur in both the Humboldt and North Coast areas. Refer to Section 2.5.1 for a description of identified reliability concerns in the Humboldt area and the proposed mitigation for this overload.

Mendocino-Redbud 115 kV #1 Line

The section of this transmission line between Red Bud and Red Bud Junction 1 may overload under category C emergency conditions during summer peak starting in 2012. No overload on this line is expected in winter. The overload is not expected to occur after 2016 when the *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) will come on line. To mitigate the overload in the interim, an operating procedure developed in the 2011 PG&E Action Plan needs to be applied.

Eagle Rock-Redbud 115 kV #1 Line

This line consists of five sections, four of which may overload under category C emergency conditions during summer peak starting in 2012. No overload on this line is expected in winter.

The Middletown 115 kV Project

(Clear Lake 60 kV System Reinforcement) will mitigate overload of the section between Highlands Junction and Cache. To mitigate the overload on this section prior to the completion of the Middletown project as well as on the three remaining overloaded sections, the operating procedure that was developed in the PG&E 2011 Action Plan and was mentioned above needs to be applied. This operating procedure will perform several switching actions and may drop some load at the Red Bud 115 kV Substation as a last resort.

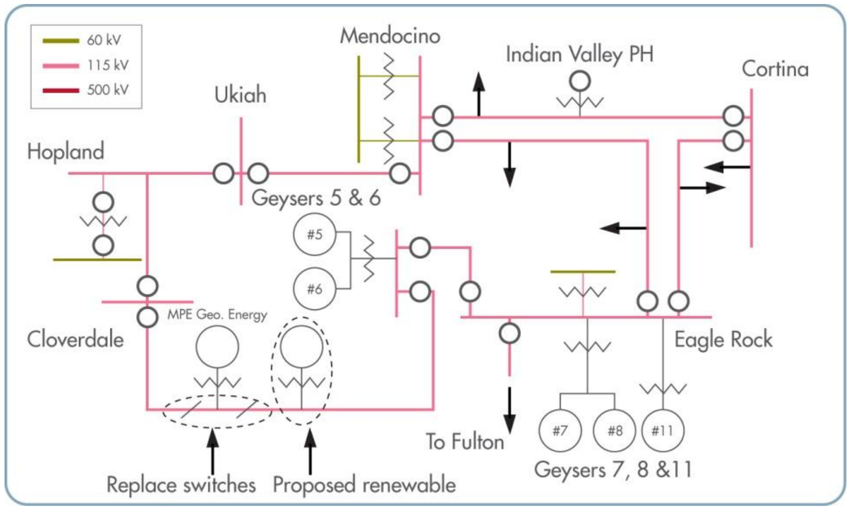
Geysers 3-Cloverdale 115 kV #1 Line

Overload on the Cloverdale-MPE Tap section of this transmission line is expected under category B contingency conditions during summer and winter peak starting in 2016. Overload under category C contingency conditions is expected starting in 2012 during summer peak and 2013 during winter peak. Loading of the Geysers 3-Cloverdale 115 kV line is significantly impacted by a new geothermal project that is planned to interconnect to this line. This project is presently on hold, and if it is not implemented, only category C overloads will be expected.

The proposed solution to mitigate these overloads is to replace the switches on the Geysers 3-Cloverdale 115 kV transmission line that are currently the limiting elements. If the switches are replaced with at least 1,000 A ratings, no overload will be expected. This replacement is an inexpensive solution to the identified reliability concern. The ISO has received a project in the Project Request Window — *Geyser #3 – Cloverdale 115 kV Line Switch Upgrades*. This project would replace the limiting equipment. Its in-service date is indicated as May 2016 or earlier. The estimated cost is between $1 million and $3 million. The ISO recommends replacing the limiting switches sooner, since the category C overload is an existing problem. Prior to the project completion, tripping of Geyser generation and — as a last resort — load at Ukiah for category C contingencies is required. Replacement of the switches will eliminate the need for these actions.

The generation and load trip needed to mitigate the overload is included in the existing PG&E 2011 Action Plan. The diagram of the proposed mitigation is shown in figure 2.5.2-1 below.

Figure 2.5.2-1: Proposed Mitigation - Geyser #3 – Cloverdale 115 kV Line Switch Upgrades



Mendocino-Clear Lake 60 kV #1 Line

All three sections of this transmission line are expected to overload under category C contingency conditions during summer peak starting in 2012. Overload of this line is not expected in winter.

The Middletown 115 kV Project

(Clear Lake 60 kV System Reinforcement), which is planned to be in service in 2016 will mitigate these overloads. In the interim, an operating procedure to open circuit breaker 22 at the Clear Lake 60 kV Substation (to Mendocino) and close the normally open circuit breaker at Middletown 60 kV (to Calistoga) will mitigate the overload. Some load tripping at Calistoga and Clear Lake may be required. This procedure is included in the PG&E 2011 Action Plan.

Mendocino-Philo-Hopland 60 kV #1 Line

The sections of this transmission line between Mendocino-Ukiah Jct-Philo Jct may overload under category C contingency conditions during summer peak starting in 2012. The interim solution to mitigate these overloads is to utilize the existing SPS that opens the Hopland 115/60 kV transformer bank and trips Ukiah and Cloverdale 115 kV load for overload on this line. The approved Middletown 115 kV Project mentioned above will mitigate the overload on the sections between Mendocino-Ukiah Jct-Philo Jct.

Also during summer peak, the section between Hopland and Philo Jct is expected to overload starting in 2016 for category C contingencies. Tripping load at Elk or Philo substations will mitigate this overload. The ISO will work with PG&E on an SPS or operating procedure if next year's Transmission Plan confirms this overload.

No overload on the Mendocino-Philo-Hopland 60 kV line is expected in winter.

Clear Lake-Eagle Rock 60 kV #1 Line

Both sections of this transmission line are expected to overload under category C contingency conditions during both summer and winter peak starting in 2012.

The Middletown 115 kV Project

(Clear Lake 60 kV System Reinforcement) planned to be in service in 2016 will mitigate overload on the section between Eagle Rock and Konocti, but will exacerbate the overload on the section between Konocti and Clear Lake. The PG&E 2011 Action Plan includes switching — such as opening a circuit breaker CB22 at the Clear Lake 60 kV Substation (to Mendocino) and closing a normally open circuit breaker at Middletown 60 kV (to Calistoga). This will mitigate the overload on both sections of the line prior to the *Middletown 115 kV Project*. To mitigate the overload on the Clear Lake-Konocti section after the *Middletown 115 kV Project* comes into service, tripping some of the Clear Lake load for category C contingencies may be required.

Clear Lake-Hopland 60 kV #1 Line

Both sections of this transmission line will overload under summer peak conditions with a category C contingency (Mendocino-Clear Lake 60 kV line together with the Eagle Rock 115/60 kV transformer). The *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) planned to be in service in 2016 will mitigate this overload. Prior to this project, the PG&E 2011 Action Plan described in the previous paragraphs will need to be applied.

Konocti-Lower Lake 60 kV #1 Line

This transmission line may overload for an outage of the Fulton-Calistoga 60 kV line together with an outage of the Eagle Rock-Cortina 115 kV line (category C) starting in 2016 under summer peak. Tripping some of the Calistoga load will mitigate both the overload and low voltages at the Calistoga and Middletown 60 kV buses.

Monte Rio-Fulton 60 kV #1 Line

The section of this line between Trenton Jct and Molino may overload under category B conditions (Fulton-Molino-Cotati 60 kV line outage) starting in approximately 2021 during summer peak and in 2012 during winter peak. With the Fulton-Molino-Cotati 60 kV line outage, the Molino load is switched from that line to the Monte Rio-Fulton 60 kV line, and the section between Trenton Jct and Molino becomes a radial feed to Molino. The Molino-Trenton Jct section will overload with this outage if Molino load exceeds this section's emergency rating. The proposed mitigation is to re-rate the line or to upgrade it if the re-rate is not possible. The ISO will work with PG&E on this mitigation plan.

Fulton-Calistoga 60 kV #1 Line

The section of this line between Fulton and St. Helena may overload under category B conditions with the Lakeville #1 60 kV line outage (Lakeville-Dunbar). The overload is expected starting in 2015 for summer peak conditions and is not expected for winter peak. With this outage, the Dunbar load is switched to the Fulton-Calistoga 60 kV line. The *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) planned to be in service in 2016 will mitigate this overload. Prior to this project, the ISO recommends closing the normally open switch 49 at Middletown (Middletown-Calistoga 60 kV line section) to mitigate the overload with this outage.

After the *Middletown 115 kV Project* is completed, opening the Middletown-Calistoga 60 kV line section of the Fulton-Calistoga 60 kV line with some category C contingencies (e.g., an Eagle Rock-Fulton-Silverado 115 kV and Geysers #9-Lakeville

230 kV double outage) will mitigate the overload on this line section that may occur with these contingencies after this section is operated as normally closed.

Lakeville #2 60 kV #1 Line

Three sections of this transmission line are expected to overload under category C contingency conditions starting in 2012 during summer peak. During winter peak, one section (Lakeville Jct-Petaluma) is expected to overload with the same contingency (Fulton-Molino-Cotati and Petaluma C-Lakeville 60 kV lines) starting in 2012, and the other two sections starting in 2015.

The proposed solution to mitigate these overloads is to utilize the existing SPS to trip load at the Petaluma 60 kV Substation in case of line overload.

Hopland 115/60 kV Transformer Bank #2

This transformer may overload for the category C contingencies, such as an outage of two Mendocino 115/60 kV banks under both summer and winter peak and Mendocino 115 kV bus under winter peak starting in 2021.

The proposed solution to mitigate this overload is to develop an SPS or an operating procedure to trip generation from the Geo Energy power plant and from the new geothermal project that is planned to interconnect to the Geysers #3-Cloverdale 115 kV line. This SPS or an operating procedure is needed by winter 2012. The ISO will work with PG&E on its development.

Lakeville 230/60 kV Transformer Bank #3

This transformer may overload for a category C contingency of the Fulton-Molino-Cotati 60 kV line together with the Lakeville 230/60 kV bank #4 starting in 2014 under summer peak. Tripping load at Dunbar or Petaluma with the second contingency is required to mitigate the overload. A new renewable project proposed to interconnect to the Lakeville #2 60 kV line will reduce the overload and mitigate it until 2021. The ISO will work with PG&E on an SPS or operating procedure.

North Bay

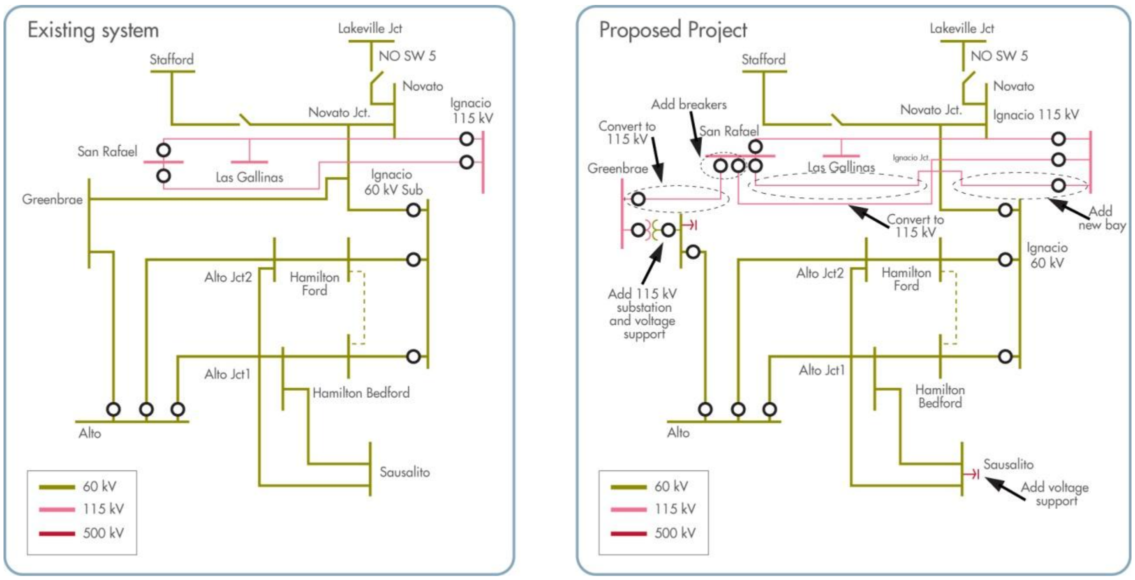
Ignacio-San Rafael 115 kV #1 Line

This transmission line is expected to overload under Categories B and C emergency conditions starting in 2012. The most limiting element on this line is a disconnect switch at the San Rafael Substation. If the switch is replaced, the overload is not expected until 2017 in summer and 2013 in winter. After that, the line upgrade will be needed.

The ISO received a project in the Request Window — *Ignacio – Alto 60 kV Line Voltage Conversion.* The scope of this project is to convert the Ignacio-Alto 60 kV transmission line from Ignacio to Greenbrae Substation (15 miles) to 115 kV operation and loop the new 115 kV line into the San Rafael Substation. The project will be implemented in two phases. First, the limiting equipment at the San Rafael Substation will be replaced. Second, the Ignacio-Alto 60 kV line section between the Ignacio and Greenbrae substations will be converted to 115 kV operation and the line will be looped into the San Rafael Substation. As a part of this conversion, the 60 kV Greenbrae Substation will be expanded to 115 kV with construction of a new 115 kV bus and installation of a 115/60 kV transformer. The project also includes installation of reactive support at the Sausalito and Greenbrae 60 kV buses that will mitigate low voltage and voltage deviation concerns. The estimated cost of the project is between $35M and $45M. The proposed in-service date is May 2014 for the first phase and May 2017 for the full project.

Figures 2.5.2-2 illustrates transmission system configuration in this area before and after the upgrade.

Figure 2.5.2-2: Ignacio–Alto 60 kV Line Voltage Conversion



One of the alternatives of this project is reconductoring the overloaded transmission lines and adding voltage support. This alternative consists of reconductoring the Ignacio- San Rafael #1 and #3 115 kV lines, as well as the Ignacio-Alto 60 kV lines and adding 20 MVar of voltage support at various locations. This alternative costs approximately $47M to $57M. It is not recommended because it does not mitigate all identified violations and has a higher cost than the proposed project. Another alternative is to reconductor the 115 kV lines that may overload for category B contingencies and install an SPS to trip load for category C contingencies. Even if the cost of this alternative ($20 million to $30 million) is lower than the cost of the proposed project, it does not mitigate all reliability concerns, such as low voltage and large voltage deviations with category B contingencies. With installation of reactive support needed for normal conditions and for category B contingencies, the cost of this alternative will be comparable to the cost of the proposed project, but its reliability will be lower since it involves the loss of load.

After reviewing this project and considering all the alternatives, the ISO concluded that the preferred alternative of converting Ignacio-Alto 60 kV transmission line to 115 kV voltage and installing necessary reactive support is an optimal solution to the identified reliability concerns. In addition to mitigating Ignacio-San Rafael 115 kV line overload, it will resolve other reliability concerns that are described in detail in the sections below. However, the ISO recommends replacing the limiting terminal equipment (phase 1 of the project) earlier than the proposed 2014, since the overload might occur as early as the winter of 2012-2013, and the replacement is needed prior to that. Replacement of the terminal equipment on the Ignacio-San Rafael 115 kV line will mitigate the category B overload of this line in 2012 and 2013.

Ignacio-San Rafael 115 kV #3 Line
The section of this line between Ignacio and Las Gallinas is expected to overload with category B and C contingencies of the parallel transmission lines starting around 2021 for the summer peak conditions. The *Ignacio – Alto 60 kV Line Voltage Conversion Project* described above will eliminate these overloads.

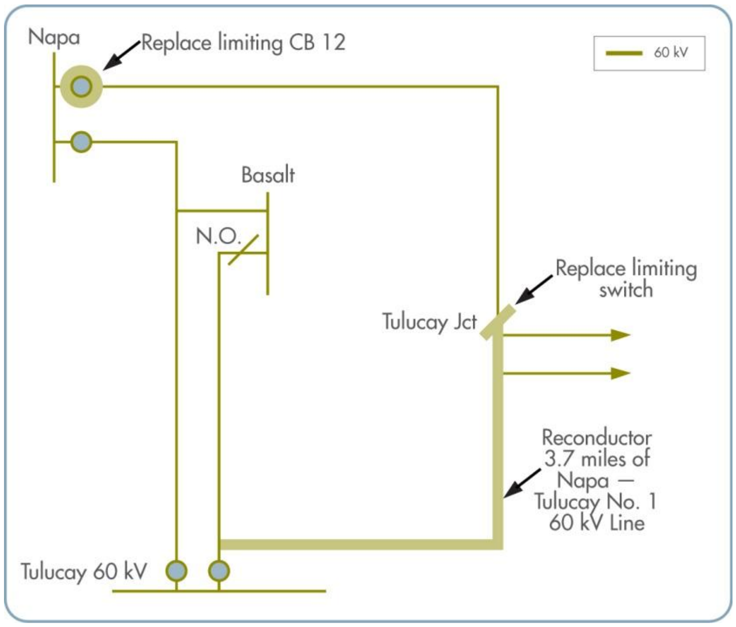
Ignacio-Alto 60 kV #1 Line
The sections of this transmission line between Ignacio Jct, San Rafael Jct and Greenbrae are expected to overload with an outage of the parallel double-circuit tower line (category C contingency) starting in 2012 under both summer and winter peak load conditions. Under winter peak load conditions, the section between Ignacio and Ignacio Jct may also overload starting in 2014. The proposed *Ignacio – Alto 60 kV Line Voltage Conversion Project* described above will eliminate these overloads. In the interim, the ISO proposes to apply an existing operating procedure that would trip the load at the Alto 60 kV Substation for the category C contingencies.

Ignacio-Alto-Sausalito 60 kV #1 and #2 Lines
The sections of these transmission lines between Ignacio and Hamilton Field are expected to overload under category C contingency conditions with an outage of the two parallel lines starting in 2012 during winter peak and in 2013 during summer peak. In addition, the studies identified insufficient reactive margin for a double outage of the Ignacio-Alto 60 kV line #1 and any one of the Ignacio-Alto Sausalito 60 kV lines starting in approximately 2021 in summer, and 2012 in winter. The proposed *Ignacio – Alto 60 kV Line Voltage Conversion Project* described above will eliminate these overloads. In the interim, an existing operating procedure that would trip load at Alto will mitigate the overload and solve the reactive margin and voltage concerns.

Napa-Tulucay 60 kV #1 Line
Both sections of this transmission line will overload with an outage of the parallel Napa-Tulucay 60 kV line #2 starting in 2012 under summer peak conditions (category B). No overload on this line is expected in winter. The limiting elements are a disconnect switch at the Tulucay Jct and a circuit breaker at the Napa 60 kV bus. After this limiting equipment is replaced, the line loading will be limited by the conductor of the Tulucay 1-Tulucay Jct section. The ISO proposes to replace the limiting equipment and to reconductor the limiting section of the line (3.7 miles).

The ISO received a project in the Project Request Window — *Napa-Tulucay No. 1 60 kV Line Upgrade*. The scope of this project is to reconductor the Napa-Tulucay #1 60 kV Line between Tulucay and Tulucay Jct., to replace existing Napa Substation Circuit Breaker #12 and to replace line switches. The in-service date of this proposed project is May 2014, and the estimated cost is between $6M and $10M. The project's diagram is illustrated in figure 2.5.2-3 below.

Figure 2.5.2-3: Napa-Tulucay No.1 60 kV Line Upgrade Project



The ISO considers the proposed project to be a prudent and cost-effective solution to the identified reliability concerns. However, since the in-service date of the project is 2014, and the overload may occur as early as summer 2012, the interim plan is for PG&E to replace the limiting switch at Tulucay Junction and Napa Substation circuit breaker portion of the project prior to the summer of 2012. If the limiting switch at the Tulucay Jct and the Napa Substation circuit breaker are replaced prior to the summer 2012, the overload will not be expected until 2014 or later. If the switch and the circuit breaker cannot be replaced prior to the next summer peak, then part of the Napa load will need to be transferred to another substation during peak load conditions.

Fulton-Santa Rosa 115 kV #1 and #2 Lines

These lines are expected to overload under category C contingency conditions starting in 2012 during summer peak. To mitigate these overloads, the ISO proposes to develop, with PG&E, operating procedures to sectionalize the remaining system after the first contingency.

Fulton-Pueblo 115 kV #1 Line

The section of this line between Pueblo and Pueblo Junction is expected to overload following an outage of a 115 kV double circuit Lakeville-Sonoma tower line (category C contingency) starting from 2012 under summer peak conditions. The proposed solution to mitigate this overload is to utilize the existing SPS to trip load at the Pueblo 115 kV substation.

Tulucay 230/60 kV Transformer Bank #1

This transformer bank may overload with an outage of the parallel Tulucay 230/60 kV bank #3 under summer peak conditions starting in 2013. The loading is limited by the circuit breaker and switches, and if they are replaced, the overload is not expected. The ISO received a project in the Project Request Window — *Tulucay 230/60 kV*

Transformer No. 1 Capacity Increase. The scope of this project is to replace the limiting equipment so that full capacity of the transformer (200 MVA) will be utilized. The proposed in-service date for the project is May 2014, and the estimated cost is between $3M and $5M. The ISO considers this project to be an optimal solution to the identified reliability concern, but recommends implementing it sooner, since the overload is expected in 2013.

Ignacio 230/115 kV Transformer Banks #4 and #6

Each of these transformers will overload for an outage of the parallel bank (category B contingency) starting in approximately 2021 under both summer and winter peak load conditions. The ISO recommends upgrading or re-rating these transformers by that time. The ISO received a project in the Project Request Window — *Ignacio 230/115 kV Transformer Addition.* This project proposes to add a third Ignacio 230/115 kV transformer bank. The project was proposed as conceptual, and its approval was not requested at this time. Since the studies did not identify the need for upgrade until 2021, the Ignacio transformers' upgrade or transformer additon will be considered in the next and future Transmission Plans.

2.5.2.4.2 Voltage Concern Mitigation

Low voltages and voltage deviation concerns caused by the delay of the approved Garberville reactive support project and their mitigations were discussed in the Humboldt Section of this report. Similar concerns were also observed for some category C outages in the North Coast area (Mendocino 115 kV bus, both Mendocino 115/60 kV transformers and double outages of several transmission lines). Prior to installation of the reactive support, the ISO recommends dispatching Kekawaka generation for peak load conditions and utilizing existing PG&E Action Plan for the Garberville area that was described in the previous section.

Low voltages and large voltage deviations were observed at the Alto and Greenbrae 60 kV substations for double contingencies of 60 kV lines between Ignacio, Alto and Sausalito (category C contingencies). For the double contingency of the Ignacio-Alto and any one of the Ignacio-Alto-Sausalito 60 kV lines, the studies identified insufficient reactive margin. The mitigation plan is to implement the transmission upgrade proposed in the *Ignacio – Alto 60 kV Line Voltage Conversion Project* that was submitted in the Request Window. This project will also mitigate the low voltage at the Sausalito 60 kV Substation under normal system conditions as well as low voltage and voltage deviation concerns at the Sausalito and Greenbrae 60 kV buses for category B contingencies. In interim, the existing operational procedure to trip Alto load for category C contingencies should be utilized.

In addition, the studies identified large voltage deviations for several category B contingencies for 2021 summer peak conditions. These include the Bolinas 60 kV bus with the Ignacio-Bolinas 60 kV line outage, Calistoga 60 kV bus with the Konocti-Lower Lake 60 kV line outage, and Covelo, Laytonville and Garberville 60 kV buses with the Willits-Laytonville 60 kV line outage. The concerns with the Willits-Laytonville outage that were also identified in the winter peak 2021 case can be mitigated by the proposed *New Bridgeville - Garberville No. 2 115 kV Line Project*. The other concerns can be mitigated with installation of additional reactive support in the 2021 time frame.

This additional reactive support will be considered in next year's Transmission Plan if the studies confirm the voltage concerns.

Other voltage concerns may be mitigated by existing SPS or operating procedures. These concerns and the mitigation plans are summarized in Appendix A.

2.5.2.5 Key Conclusions

A summary of the ISO assessment of the PG&E North Coast/North Bay revealed the following reliability concerns:

- One overload under normal conditions (Bridgeville-Garberville 60 kV line) in 2021, which was also discussed in the Humboldt section of this report
- One bus with low voltage concern under normal conditions (Sausalito 60 kV)
- Ten overloads caused by nine critical single contingencies under summer peak conditions, and five overloads caused by five critical single contingencies under winter peak conditions
- Thirty-five overloads caused by various multiple contingencies under summer peak conditions, and 15 overloads caused by various critical multiple contingencies under winter peak conditions
- Two facilities with low voltage concerns and 11 with voltage deviation concerns with category B contingencies under both summer and winter peak conditions
- Multiple voltage concerns under category C contingencies

In order to address the identified overloads, the ISO proposes the following:

- Replace limiting equipment on the Geysers 3-Cloverdale 115 kV transmission line
- Upgrade or re-rate the Trenton Jct-Molino section of the Fulton-Monte Rio 60 kV transmission line
- Upgrade the 60 kV transmission system in the Ignacio-San Rafael-Alto area
- Replace limiting equipment on the Napa-Tulucay 60 kV line #1
- Replace limiting equipment at the Tulucay 230/60 kV transformer bank #2
- Upgrade or re-rate Ignacio 230/115 kV transformer banks #4 and #6
- Utilize existing procedures and develop new SPS or operating procedures for category C contingencies

The ISO received five proposed transmission projects through the 2011-2012 Request Window. The ISO determined that four projects were consistent with the ISO's proposed mitigation solutions and are needed to mitigate the identified reliability concerns. These projects include the following:

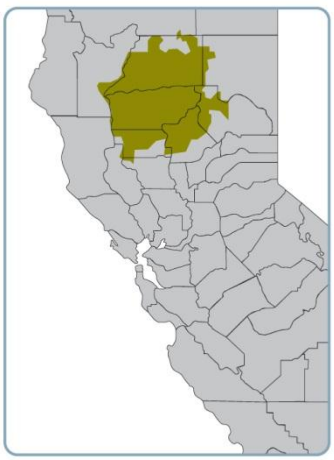
- Ignacio - Alto 60 kV Line Voltage Conversion Project;
- Napa - Tulucay No. 1 60 kV Line Upgrade;
- Tulucay No. 1 230-60 kV Transformer Capacity Increase; and,
- Geyser #3 - Cloverdale 115 kV Line Switch Upgrade.

The fifth project, Ignacio 230-115 kV Transformer Addition, was proposed as a conceptual project, since it is not expected to be needed until approximately 2021.

2.5.3 North Valley Area

2.5.3.1 Area Description

The North Valley area is located in the northeastern corner of the PG&E's service area and covers approximately 15,000 square miles. This area includes the northern end of the Sacramento Valley, and parts of the Siskiyou and Sierra mountain ranges and the foothills. Chico, Redding, Red Bluff and Paradise are some of the cities in this area. The adjacent figure depicts the approximate geographical location of the North Valley area.



North Valley's electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. The 500 kV facilities are part of the Pacific Intertie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific Intertie, also run north to south, with connections to hydroelectric generation facilities. The 115 kV and 60 kV facilities serve the local electricity demand. In addition to the Pacific intertie, there is one other external interconnection to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via the Cottonwood, Table Mountain, Palermo and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. Load forecasts indicate North Valley should reach a summer peak demand of 1,048 MW by 2021, assuming load is increasing at approximately 12 MW per year.

Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions. Table 2.6-2 includes load forecast data.

2.5.3.2 Area-Specific Assumptions and System Conditions

The North Valley area study was performed consistent with the general study methodology and assumptions described in Section 2.3. The ISO-secured website (i.e., ISO Market Participant Portal) lists contingencies that were performed as part of this assessment. Additionally, specific methodology and assumptions that are applicable to the North Valley area study are provided below.

Generation

Generation resources in the North Valley area consist of market, qualifying facilities and self-generating units. More than 2,000 MW of hydroelectric generation is created by facilities in this area. These facilities are fed from the following river systems: Pit River, Battle Creek River, Cow Creek, North Feather River, South Feather River, West Feather River and Black Butt. Some of the large powerhouses on the Pit River and the Feather River watersheds are: Pit, James Black, Caribou, Rock Creek, Cresta, Butt Valley, Belden, Poe and Bucks Creek. The largest generation facility in the area is the Colusa County generation plant. This plant consists of a combined total capacity of 717 MW, and it is interconnected to the four Cottonwood-Vaca Dixon 230 kV lines. A list of all the generating facilities in the North Valley area is provided in Table 2.5.3-1.

Table 2.5.3-1: Generation in the North Valley Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Pit River	Hydro	752
2	Battle Creek	Hydro	17
3	Cow Creek	Hydro	5
4	North Feather River	Hydro	736
5	South Feather River	Hydro	123
6	West Feather River	Hydro	26
7	Black Butte	Hydro	11
8	CPV Colusa	Thermal	717
9	Hatchet Ridge Wind	Wind	103
10	QFs	Co-Gen	353
	Total Generation		2,843

Load Forecast

Loads within the North Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.5.3-2 shows loads modeled for the North Valley area assessment as well as other local areas within PG&E system.

Table 2.5.3-2: Load forecasts modeled in the North Valley area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast						
PG&E Area Name	**Summer Peak (MW)**					
	2012	**2013**	**2014**	**2015**	**2016**	**2021**
North Valley	**928**	**955**	**963**	**976**	**992**	**1,048**

2.5.3.3 Study Results and Discussion

A summary of the study results of facilities in the North Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions
For the summer peak cases, all facilities met the thermal loading performance requirements. Eight facilities were identified with high voltage concerns under normal conditions.

For the spring off-peak cases, all facilities met the thermal loading performance requirements. Multiple facilities were identified with high voltage concerns under normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)
For the summer peak cases, three facilities were identified with thermal overloads. Three facilities were identified with low voltage and voltage deviation concerns under the category B contingency conditions.

For the spring off-peak cases, two facilities were identified with thermal overloads. Multiple facilities were identified with high voltage concerns under the category B contingency conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements
For the summer peak cases, 14 facilities were identified with thermal overloads. Three facilities were identified with low voltage concerns and five were identified with voltage deviation concerns under the category C contingency conditions.

For the spring off-peak cases, eight facilities were identified with thermal overloads. Multiple facilities were identified with high voltage and voltage deviation concerns under the category C contingency conditions.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and spring off-peak conditions along with the corresponding proposed solutions.

2.5.3.4 Recommended Solutions

Based on this year's reliability assessment results for the North Valley area, the ISO initially recommended solutions to address system performance results for the facilities that did not meet the thermal and voltage performance requirements under Categories A (normal), B and C contingency conditions. The ISO then evaluated the initial recommended solutions as well as submissions made through the Request Window process.

Following is a discussion of the ISO's analysis and the projects that were determined to be needed to address thermal and voltage performance requirements. This includes information about the expected in-service dates of the mitigation projects and plans that are designed to achieve the required system performance over the planning horizon.

2.5.3.4.1 Thermal Overload Mitigations

Cottonwood-Red Bluff and Coleman-Red Bluff 60 kV Lines

The ISO identified an existing overload on the Cottonwood-Red Bluff and Coleman-Red Bluff 60 kV lines under category B contingency conditions. To mitigate this overload the ISO previously approved a PG&E project — the *Red Bluff Area 230/60 kV Substation and Cottonwood-Red Bluff No. 2 60 kV Line Project* — with an in-service date of May 2014. Operating action plans are in place to address these reliability concerns in the interim.

Cottonwood-Benton-Deschutes and Cottonwood-Benton #1 60 kV Lines

The ISO identified an existing overload on the Cottonwood-Benton-Deschutes 60 kV line under category B contingency conditions. Additionally, the Cottonwood-Benton #1 60 kV line was identified with existing overloads under category C contingency conditions. To mitigate these overloads, the ISO previously approved a PG&E project — *Cascade 115/60 kV No. 2 Transformer and Cascade-Benton 60 kV Line*. This project will install a new 115/60 kV transformer bank at the Cascade substation. The project has an in-service date of May 2014. Operating action plans are in place to address these reliability concerns in the interim.

Keswick-Cascade and Keswick-Trinity-Weaverville 60 kV Lines

The ISO identified an existing overload on the Keswick-Cascade and Keswick-Trinity-Weaverville 60 kV Lines under category C contingency conditions. The category C contingencies causing these overloads include Cascade-Benton-Deschutes 60 kV line. The previously ISO-approved project – *Cascade-Benton 60 kV Line*, which has a 2014 in-service date — will eliminate these overloads. Operating action plans are in place to address these reliability concerns in the interim.

Table Mountain/Chico Area 115 kV Lines

All four 115 kV lines emanating from the Table Mountain Substation and serving the Chico/Sycamore area have been identified with existing thermal overloads under various category C contingency conditions. To mitigate these overloads, the ISO previously approved a PG&E project — *Table Mountain-Sycamore 115 kV Line Project.* This project will build a new 115 kV line from the Table Mountain to Sycamore substation. The project has an in-service date of May 2015. Operating action plans are in place to address these reliability concerns in the interim.

2.5.3.4.2 Voltage Concern Mitigation

Three substations were identified as not meeting the required voltage performance under category B contingency conditions. Five substations were identified as not meeting the required voltage performances under category C contingency conditions.

The concerns at substations identified as not meeting the voltage performance requirements will be addressed upon implementation of the projects discussed above under the thermal overload mitigation section. The substations identified with high voltages are under review for possible exemption.

2.5.3.5 Key Conclusions

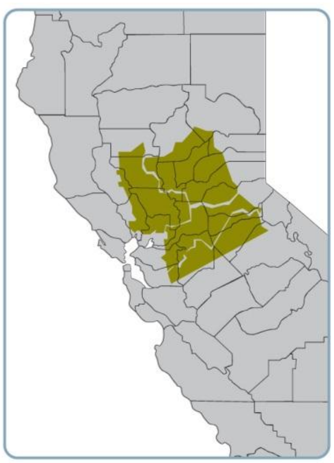
The 2011 reliability assessment of the PG&E North Valley area identified several reliability concerns. These concerns consist of thermal overloads and low voltages under Categories B as well as category C contingency conditions. The ISO previously approved capital projects that mitigate these reliability concerns in the long-term. The substations identified with high voltages are under review for possible exemption and/or for some area-wide reactive support.

Until the approved projects are completed, operating action plans will be relied upon for mitigation. Although operating procedures will address the reliability concerns, they will continue to be identified in annual planning studies for years prior to the forecast in-service dates of these projects.

2.5.4 Central Valley Area

2.5.4.1 Area Description

The Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley, and it is composed of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



Sacramento covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of the Sacramento Municipal Utility District and Roseville. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is composed of 60, 115, 230 and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system is composed of 60, 115 and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 and 230 kV facilities transmit generation resources from the north to the south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the State of Nevada (Path 24).

Stockton is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system is composed of 60, 115 and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. The City of Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system is composed of 230, 115 and 60 kV facilities. The 230 kV facilities connect Bellota to the Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area, and it has connections to qualifying facilities generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via a 115/60 kV transformer bank at Salado.

Historically, the Central Valley experiences its highest demand during the summer season. Load forecasts indicate the Central Valley should reach its summer peak demand of 4,348 MW by 2021 assuming load is increasing by approximately 59 MW per year.

Accordingly, system assessments in these areas included technical studies using load assumptions for these summer peak conditions. Table 2.5-4 includes load forecast data.

2.5.4.2 Area-Specific Assumptions and System Conditions

The Central Valley area study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured website lists contingencies that were performed as part of this assessment. Additionally, specific methodology and assumptions that are applicable to the Central Valley area study are provided below.

Generation

Generation resources in the Central Valley area consist of market, QFs and self-generating units. These are shown in tables 2.5.4-1 to 2.5.4-4. The total installed capacity is approximately 3,459 MW with another 530 MW of North Valley generation being connected directly to the Sierra division. The following table summarizes the generation capacity in the Sacramento area. More than 800 MW of the capacity listed below (Lambie, Creed, Goosehaven, EnXco, Solano, High Winds and Shiloh) are connected to the new Birds Landing Switching Station and primarily serves the Bay Area loads.

Table 2.5.4-1: Generation in the Sacramento Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Wadham	Biomass	27
2	Woodland Biomass	Biomass	25
3	UC Davis Co-Gen	Co-Gen	4
4	Cal-Peak Vaca Dixon	CT	49
5	Wolfskill Energy Center	CT	60
6	Lambie, Creed and Goosehaven	CT	143
7	EnXco	Wind	60
8	Solano	Wind	100
9	High Winds	Wind	200
10	Shiloh	Wind	300
	Total Generation		968

The following table summarizes the generation capacity in the Sierra area. There is approximately 1,247 MW of internal generating capacity within the Sierra Division, and more than 530 MW of hydro generation listed under North Valley that flows directly into the Sierra electric system. More than 75 percent of this generating capacity is from hydro resources. The remaining 25 percent of the capacity is from QFs, and co-generation plants. The Colgate Powerhouse (294 MW) is the largest generating facility in the Sierra Division.

Table 2.5.4-2: Generation in the Sierra Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Bowman Power House	Hydro	4
2	Camp Far West (SMUD)	Hydro	7
3	Chicago Park Power House	Hydro	40
4	Chili Bar Power House	Hydro	7
5	Colgate Power House	Hydro	294
6	Deer Creek Power House	Hydro	6
7	Drum Power House	Hydro	104
8	Dutch Flat Power House	Hydro	49
9	El Dorado Power House	Hydro	20
10	Feather River Energy Center	Hydro	50
11	French Meadows Power House	Hydro	17
12	Green Leaf No. 1	QF/Co-Gen	73
13	Green Leaf No. 2	QF/Co-Gen	50
14	Halsey Power House	Hydro	11
15	Haypress Power House	Hydro	15
16	Hellhole Power House	Hydro	1
17	Middle Fork Power House	Hydro	130
18	Narrows Power House	Hydro	66
19	Newcastle Power House	Hydro	14
20	Oxbow Power House	Hydro	6
21	Ralston Power House	Hydro	83
22	Rollins Power House	Hydro	12
23	Spaulding Power House	Hydro	17
24	SPI-Lincoln	QF/Waste	18
25	Ultra Rock (Rio Bravo-Rocklin)	Biomass	25
26	Wise Power House	Hydro	20
27	Yuba City	CT	49
28	Yuba City Energy Center	QF/Co-Gen	61
	Total Generation		1,247

The Stockton area has about 1,371 MW of internal generating capacity. The following table summarizes the generation resources within the area.

Table 2.5.4-3: Generation in the Stockton Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Altamont Co-Generation	QF/Co-Gen	7
2	Camanche Power House	Hydro	11
3	Co-generation National POSDEF	QF/Co-Gen	44
4	Electra Power House	Hydro	101
5	Flowind Wind Farms	Wind	76
6	GWF Tracy Peaking Plant	CT	192
7	Ione Energy	QF/Co-Gen	18
8	Lodi Stigg (NCPA)	QF/Co-Gen	21
9	Pardee Power House	Hydro	29
10	Salt Springs Power House	Hydro	42
11	San Joaquin Co-Generation	QF/Co-Gen	55
12	Simpson Paper Co-Generation	QF/Co-Gen	50
13	Stockton Co-Generation (Air Products)	QF/Co-Gen	50
14	Stockton Waste Water Facility	QF/Co-Gen	2
15	Thermal Energy	QF/Biomass	21
16	Tiger Creek Power House	Hydro	55
17	US Wind Power Farms	Wind	158
18	West Point Power House	Hydro	14
19	ISO Queue 267	CC	280
20	ISO Queue 268	ST	145
	Total Generation		1,371

The Stanislaus area has about 590 MW of internal generating capacity. More than 90 percent of this generating capacity is from hydro resources. The remaining capacity consists of QFs and co-generation plants. The Melones power plant is the largest generating facility in the area. The following table summarizes the generation facilities.

Table 2.5.4-4: Generation in the Stanislaus Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Beardsley Power House	Hydro	11
2	Donnells Power House	Hydro	68
3	Fiberboard (Sierra Pacific)	QF/Co-Gen	6
4	Melones Power Plant	Hydro	119
5	Pacific Ultra Power Chinese Station	QF/Waste	22
6	Sand Bar Power House	Hydro	15
7	Spring Gap Power House	Hydro	7
8	Stanislaus Power House	Hydro	83
9	Stanislaus Waste Co-gen		24
10	Tulloch Power House	Hydro	17
	Total Generation		323

Load Forecast

Loads within the Central Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.5.4-5 shows loads modeled for the Central Valley area assessment as well as other local areas within PG&E system.

Table 2.5.4-5: Load forecasts modeled in the Central Valley area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast						
PG&E Area	**Summer Peak (MW)**					
	2012	**2013**	**2014**	**2015**	**2016**	**2021**
Sacramento	**1,078**	**1,092**	**1,101**	**1,115**	**1,128**	**1,206**
Sierra	**1,159**	**1,185**	**1,206**	**1,232**	**1,257**	**1,400**
Stockton	**1,294**	**1,311**	**1,324**	**1,344**	**1,362**	**1,485**
Stanislaus	**223**	**226**	**229**	**233**	**236**	**257**
TOTAL	**3,754**	**3,814**	**3,860**	**3,924**	**3,983**	**4,348**

2.5.4.3 Study Results and Discussion

A summary of the study results of facilities in the Central Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, three facilities were identified with thermal overloads. Eleven facilities were identified with low voltage concerns, and one facility was identified with high voltage concerns under the normal conditions.

For the Sierra area spring off-peak cases, all facilities met the thermal loading performance requirements. Multiple facilities were identified with high voltage concerns under normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

For the summer peak cases, eight facilities were identified with thermal overloads. Seven facilities were identified with low voltage concerns and 26 facilities were identified with high voltage deviation concerns under the category B contingency conditions.

For the Sierra area spring off-peak cases, all facilities met the thermal loading performance requirements. Thirteen facilities were identified with high voltage deviations, and multiple facilities were identified with high voltage concerns under the category B contingency conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, 39 facilities were identified with thermal overloads. Thirty-five facilities were identified with low voltage concerns, and 48 facilities were identified with high voltage deviation concerns under the category C contingency conditions.

For the Sierra area spring off-peak cases, one facility was identified with thermal overload. Four facilities were identified with high voltage deviations, and multiple facilities were identified with high voltage concerns under category C contingency conditions.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and Sierra area spring off-peak conditions along with the corresponding proposed solutions.

2.5.4.4 Recommended Solutions

Based on this year's reliability assessment results of the Central Valley area, the ISO initially recommended solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories A (normal), B and C contingency conditions. The ISO then evaluated the initial recommended solutions as well as submissions made through the Request Window process.

Following is a discussion of the ISO/s analysis and the projects that were determined to be needed to address the thermal and voltage performance requirements. This includes information about the expected in-service dates of the mitigation projects and plans.

2.5.4.4.1 Thermal Overload Mitigations

Sacramento Division Thermal Overload Mitigations

Vaca-Suisun-Jameson 115 kV

The ISO identified an overload on the Vaca-Suisun-Jameson 115 kV line under a category B contingency starting in 2021. Currently, there is also one category C contingency that was forecast to overload this line, and an SPS is used to trip load as mitigation. The ISO-identified solution would include reconductoring about 18 miles of this line. There is ample time for permitting, procurement and installation of a project before 2021. Accordingly, the ISO will assess this and other mitigation plans further in a future ISO transmission plan.

Vaca Dixon-Davis Voltage Conversion

The ISO identified existing thermal overloads on the Brighton-Davis 115 kV line; the Rio Oso-West Sacramento 115 kV line; the Vaca Dixon 230/115 kV bank #2 and #2A; and the Woodland-Davis 115 kV line under category C contingency conditions. To mitigate these overloads, the ISO previously approved a PG&E project — *Vaca Dixon – Davis Voltage Conversion Project*. The project is planned to convert the Vaca Dixon 60 kV system to a 115 kV operation and connect to the Davis 115 kV system. The project has an in-service date of May 2015. Operating action plans are in place to address these reliability concerns in the interim.

West Coast Recycling - Load Interconnection

West Coast Recycling (WCR) is proposing to construct and operate a state-of-the-art scrap metal shredding and recycling facility at the Port of West Sacramento. Operations at the facility will include scrap metal sorting and shredding, material separation and processing to extract reusable material. It will also include stabilization of non-metallic material to make it useful as sanitary day cover in landfills. The expected maximum electric load of the project is approximately 7 MW. To facilitate this interconnection, PG&E submitted a project in the 2011 Request Window — the *West Coast Recycling - Load Interconnection*. This project is planned to interconnect WCR's proposed facilities by tapping onto the existing Deepwater Tap #2 115 kV line. This tap line will be approximately 0.7 miles long.

The ISO has reviewed the interconnection facilities proposed by PG&E and has determined that the proposed interconnection will allow the load to be reliably interconnected to the ISO-controlled grid. No reliability upgrades or additions to the ISO-controlled grid will be triggered by the tap line and associated facilities. Thus, the ISO has determined that this proposed load interconnection to the PG&E 115 kV system may proceed without modification. The radial tap line and associated facilities will not be under the ISO's operational control.

Sierra Division Thermal Overload Mitigations

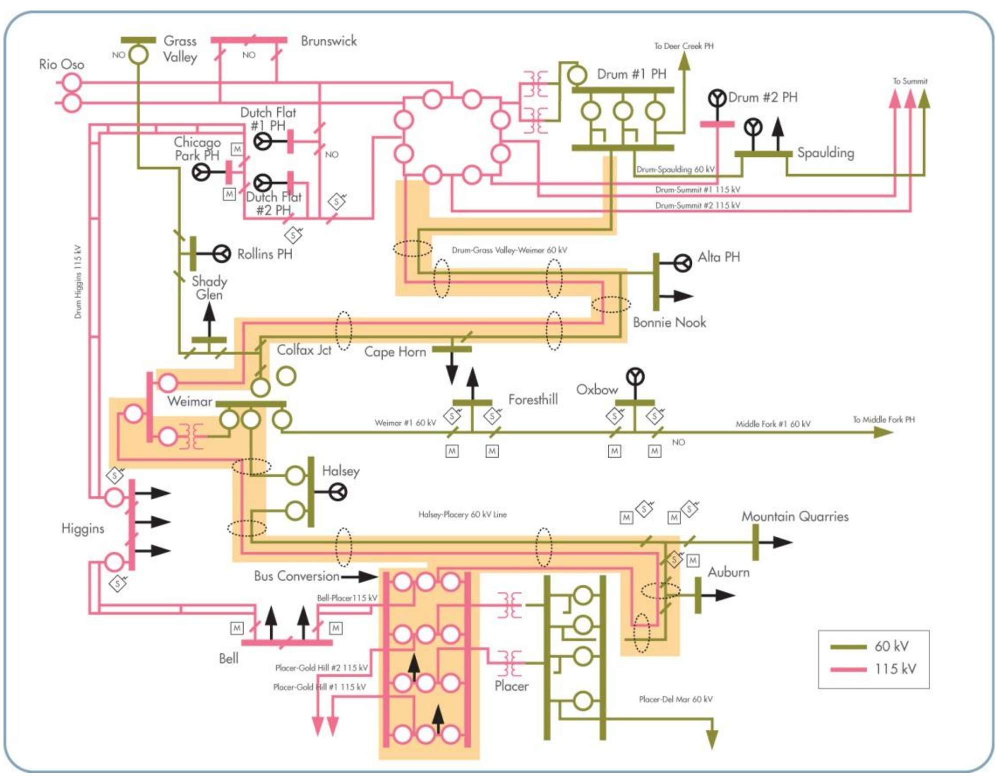
New Drum-Placer 115 kV Line

This year's assessment identified the following facilities in the Drum and Placer areas as not meeting the thermal and voltage performance requirements:

- Placer 115/60 kV Transformer #1 overload (starting in 2021 under category A)
- Drum-Higgins 115 kV line overload (starting in 2021 under category A and existing under Categories C)
- Drum-Rio Oso 115 kV Line #1 (existing overload under category C)
- Drum-Rio Oso 115 kV Line #2 (existing overload under category B and C)
- Drum-Grass Valley-Weimar 60 kV Line (existing overload under category B)
- Gold Hill 230/115 kV Transformer #1 (existing overload under category C)
- Gold Hill 230/115 kV Transformer #2 (existing overload under category C)
- Placer-Gold Hill 115 kV Line #1 (existing overload under category C)
- Placer-Gold Hill 115 kV Line #2 (existing overload under category C)
- Drum Area Voltages (starting in 2015 under category B)
- Atlantic/Placer Area Voltages (starting in 2015 under category B and existing and potential voltage collapse under category C)

Figure 2.5.4-1 below shows the diagram of the proposed New Drum-Placer 115 kV Line.

Figure 2.5.4-1: Proposed New Drum-Placer 115 kV Line



To mitigate these overloads and voltage issues, PG&E submitted a project through the 2011 Request Window — the *New Drum-Placer 115 kV Line Project*. This project proposes to rebuild and reconductor the existing Drum-Grass Valley-Weimar; Weimar-Halsey; and Halsey-Placer 60 kV lines with a DCTL consisting of a 60 kV line and a 115 kV line. The project, as proposed, does not include substation work scope required at Drum 115 kV Substation. Drum 115 kV is currently a 7-terminal ring bus, and adding an additional terminal or converting to a breaker-and-a-half bus configuration could be challenging because of space limitations at the facility. The ISO is working with PG&E to evaluate this issue, and will also evaluate other alternative of building a new switching station around the Drum-Rio Oso and Drum-Higgins 115 kV lines intersection. . With this the ISO is not identifying the New Drum-Placer 115 kV Line project as needed in this plan and will continue to assess the needs and alternatives to address the reliability needs in the area in future planning assessments. Operating action plans are in place to address these reliability concerns in the interim.

The following PG&E identified alternatives to the *New Drum-Placer 115 kV Line Project* were considered:

- *Atlantic-Placer Voltage Conversion Project*
  This alternative involves converting the 60 kV lines between Atlantic and Placer to 115 kV. It is not recommended because it does not mitigate the expected capacity constraints on the Drum-Grass Valley-Weimar 60 kV Line or the Drum-Higgins and Drum-Rio Oso 115 kV Line #1 and #2.
- *Drum Area Reinforcement*
  This alternative involves the following separate fixes: replacing the Placer 115/60 kV transformer; reconductoring the Drum-Higgins 115 kV Line; reconductoring the Drum-Rio Oso 115 kV Line #2; reconductoring the Drum-Grass Valley-Weimar 60 kV Line; and adding shunt caps at Grass Valley and Higgins substations. It is not recommended because it does not correct many of the category C issues in the area, and it does not improve reliability or operational flexibility in the area.
- *Drum-Placer 60 to 115 kV Conversion*
  This alternative involves reconductoring and converting the Drum-Grass Valley-Weimar, Weimar #1, Weimar-Halsey, and Halsey-Placer 60 kV Lines to 115 kV including 7 substations. It also includes adding a new 115 kV bus and 115/60 KV transformer at Shady Glen as well as installing shunt caps at Forest Hill. This alternative is not recommended because it does not improve reliability and operational flexibility better than the proposed alternative. Implementing this project while still maintaining reliable service will be difficult because of clearance limitations.
- *Drum-Placer 60 kV Reinforcement Project*
  This alternative involves the following: reconductoring the Drum-Grass Valley-Weimar, Weimar-Halsey, and Halsey-Placer 60 kV Lines; reconductoring the Drum-Higgins 115 kV Line; adding a new Placer 115/60 kV transformer; replacing the existing 115/60 kV Placer transformer; and upgrading the Placer 115 kV bus. This alternative is not recommended because it does not fix all

overloads nor does it improve reliability and operational flexibility nearly as much as the proposed alternative.

- *New Grass Valley 115 kV Source*
  This alternative involves adding a new 115 kV source to Grass Valley from the Brunswick taps, which would also require reconductoring the Drum-Rio Oso 115 kV Lines. This alternative is not recommended because it does not mitigate all the issues on the Drum 115 kV system or the Placer area.

WGD proposed an energy storage reliability-driven project in 2010 Request Window, *the Auburn 60 kV Energy Storage Project* to address some of the reliability concerns in the Placer area. The ISO staff also considered the proposed energy storage project as an alternative. It is not recommended because it does not mitigate the overloads and voltage concerns in the Drum 115 kV system.

South of Palermo 115 kV Reinforcement

The ISO identified existing thermal overloads on the Bogue-Rio Oso 115 kV line and Pease-Rio Oso 115 kV line under category C contingency conditions. To mitigate these overloads, the ISO previously approved a PG&E project — *South of Palermo 115 kV Reinforcement*, which is planned to reconductor the southern portions of the Palermo-Rio Oso 115 kV lines #1 and #2 as well as the entire Palermo-Pease and Pease-Rio Oso 115 kV lines with 1,113 kcmil aluminum conductor. The project has an in-service date of May 2014. Operating action plans are in place to address these reliability concerns in the interim.

Atlantic-Gold Hill 230 kV and Rio Oso-Lincoln-Atlantic 115 kV Lines

The Atlantic-Gold Hill 230 kV line is expected to overload starting in 2016 under category C contingencies. There are also existing overloads on the Rio Oso-Lincoln and Lincoln-Pleasant Grove 115 kV lines under a category C contingency involving the Rio Oso-Atlantic 230 kV line. To mitigate these overloads, the ISO previously approved a PG&E project — *Rio Oso-Atlantic 230 kV Line Project*, which consists of installing a second 230 kV line between the Rio Oso and Atlantic substations. The project has an in-service date of May 2016. Operating action plans are in place to address these reliability concerns in the interim.

Gold Hill-Missouri Flat #1 115 kV Line

In its 2008 Transmission Plan, the ISO approved a project to reconductor the Gold Hill-Missouri Flat 115 kV lines to mitigate then-identified category B overloading concerns. The Gold Hill-Missouri Flat #1 115 kV line still has an existing overload under a category C contingency condition. Additionally, the Clarksville Substation has close to 200 MW of load and should be looped in. Solutions include upgrading the Clarksville Substation to 230 kV operations or building a new 230 kV substation by looping the 230 kV lines in the area. Due to permitting and lead times, the most feasible project implementation date, is 2016. Operating action plans are in place to address these reliability concerns in the interim.

Westwood Area Upgrades

PG&E submitted a project through the 2010 Request Window — *the Westwood Area Upgrades*, which proposes reconductoring 21 miles of the Caribou-Westwood 60 kV line and installing two SPS. These upgrades are driven by the interconnection of two new generation projects in the Lassen Municipal Utility District (LMUD) system. LMUD, in 2011 Request Window, submitted further information supporting the Westwood Area Upgrade project. LMUD's 60 kV system is directly connected to PG&E's Westwood substation via two LMUD-owned 60 kV transmission lines in Lassen County. PG&E intends to upfront the cost of these upgrades and recover those costs through the transmission access charge (TAC).

The issue of cost responsibility for network upgrades on the ISO system required by generators interconnecting to non-PTO systems in the ISO BAA has been addressed in a recent generation interconnection process (GIP) filing. On November 30, 2011, the ISO submitted proposed tariff revisions that will allow generation projects such as those seeking interconnection to the LMUD system to enter to the ISO interconnection queue and be studied for full capacity deliverability status. A FERC decision on this proposal is expected very shortly, at which time the ISO will confer with PG&E and LMUD to address interconnection and cost recovery options for these projects. Thus, the need for the network upgrades submitted by PG&E in the 2010 request window will be addressed in GIP rather than in the transmission planning process.

Hammer-Country Club 60 kV Line, Stagg-Country Club #1 and #2 and Stagg-Hammer 60 kV Lines

The ISO identified existing thermal overloads on the Stagg-Country Club #1 and #2 and Stagg-Hammer 60 kV lines under category C contingency conditions. To mitigate these overloads, the ISO previously approved two PG&E projects — *Hammer-Country Club 60 kV Switch Project* and the *Stagg-Hammer 60 kV Line Project*. The *Hammer-Country Club 60 kV Switch Project* consists of replacing the limiting switch on this line and re-rating a small section at the Country Club end. The *Stagg-Hammer 60 kV Line Project* consists of building a second 60 kV line (approximately 4.2 miles in length) between the Stagg and Hammer substations. The switch-replace project has an in-service date of May 2012, and the new line project has an in-service date of May 2014. Operating action plans are in place to address these reliability concerns in the interim.

Tesla-Manteca Area 115 kV Lines

The ISO identified existing overloads on the Tesla-Tracy, Tesla-Schulte Switching Station, Tesla-Kasson-Manteca and Vierra-Tracy-Kasson 115 kV lines under various category C contingency conditions. To mitigate these overloads, the ISO previously approved a PG&E project — *Vierra 115 kV Looping Project*, which is planned to loop the Tesla-Stockton Co-gen 115 kV line into the Vierra Substation. The project has an in-service date of May 2014. Operating action plans are in place to address these reliability concerns in the interim.

Lockeford-Industrial, Lodi-Industrial, Lockeford 230/60 kV Transformers and Lockeford-Lodi 60 kV Lines

The Lockeford/Lodi area 60 kV lines were identified with existing overloads under various category C contingency conditions. Additionally, the Lockeford 230/60 kV transformer #2 and #3 are expected to overload starting in 2018 under category C contingency conditions. The Mosher Substation has more than 50 MW of load and, as such, it should have two lines of supply. For these potential overloads, there is an ongoing 2010 Request Window project, which proposes to build a new 230/60 kV substation in the vicinity of the existing industrial substation and to build two new 60 kV lines from the new substation to the industrial substation. Working with PG&E and NCPA, the ISO is evaluating different alternatives to bringing additional transmission capacity into the Lodi area as a long-term solution. Due to permitting and lead times, the most feasible project implementation is 2016. Operating action plans are in place to address these reliability concerns in the interim.

Weber #2 230/60 kV Transformer

The Weber #2 230/60 kV transformer was identified as having an existing overload under a category B contingency condition. Under category C, this overload is aggravated by any generator loss in this area. To mitigate these overloads, the ISO previously approved a PG&E project — *Weber 230/60 kV Transformer Replacement Project*, which is planned to replace Weber 230/60 kV Transformer #2 and #2a with a new single transformer. The project has an in-service date of May 2013. Operating action plans are in place to address these reliability concerns in the interim.

Valley Spring #1 60 kV Line

The Valley Spring #1 60 kV line was identified as overloaded starting in 2021 under a category B contingency condition. This overload occurs when the Linden Substation is transferred to this line because of an outage of the Weber-Mormon Junction 60 kV line. Reconductoring this line could be a solution. There is ample time for permitting, procurement and installation before 2021. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

Valley Spring-Martell #2 60 kV Line

The Valley Spring-Martell #2 60 kV Line was identified as overloaded starting in year 2021 under normal condition. Solutions include rerating or reconductoring the line. There is ample time for permitting, procurement and installation before 2021. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

Stanislaus-Manteca #2 115 kV Line

The Stanislaus-Manteca #2 115 kV line was identified with an existing overload under a category C contingency. The solution includes developing an operating solution to reduce generation at Stanislaus following the first contingency. The most feasible implementation timeline is 2012.

Stanislaus-Melones-Manteca #1 115 kV Line

The Stanislaus-Melones-Manteca #1 115 kV line was identified with an existing overload under a category C contingency. Solutions include obtaining a short-term rating and developing an operating solution to reduce generation at Stanislaus following the contingency or installing an SPS for the same action. The most feasible implementation timeline for this upgrade is 2012.

Stockton 'A'-Lockeford-Bellota #1 and #2 115 kV Line

The ISO identified an overload on the Stockton 'A'-Lockeford-Bellota #1 115 kV line starting in 2021 under a category B contingency condition. The Stockton 'A'-Lockeford-Bellota #2 115 kV line is also identified with category C overload starting in 2017. Solution includes rerating or reconductoring the lines. Operating solutions to re-adjust the system following the first contingency or installing an SPS to curtail load following the second contingency can also be used for the #2 line. There is ample time for permitting, procurement and installation before 2017. This plan, and other possible options, will be assessed in a future ISO transmission plan.

2.5.4.4.2 Voltage Concern Mitigation

Sacramento Area 115 kV Substations

The ISO identified existing low voltages in the Sacramento area 115 kV substations following a category C contingency in which both 230 kV lines coming into the Brighton Substation are lost. The *Vaca-Davis Voltage Conversion Project* discussed in the preceding section will also mitigate these voltage concerns in the Sacramento area 115 kV system. The project has an in-service date of May 2015. Operating action plans are in place to address these reliability concerns in the interim.

Plainfield 60 kV Substation

The ISO identified normal low voltage in the Plainfield 60 kV bus starting in 2013. The *Vaca-Davis Voltage Conversion Project* discussed above will also mitigate this voltage concern. An operating action plan is in place to address this reliability concern in the interim.

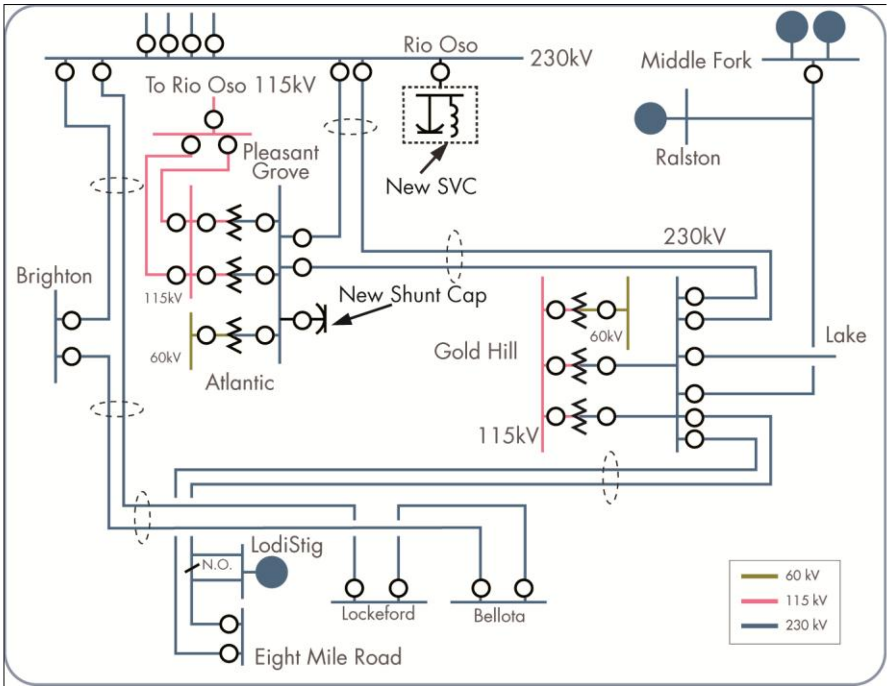
Cortina 60 kV Substations

The ISO identified existing high voltage deviation in the Cortina area 60 kV substations under a category B contingency. The solution is to add reactive support in the Cortina 60 kV system. Because of permitting and lead times, the most feasible project implementation time frame is 2014. An operating action plan is in place to address this reliability concern in the interim.

Rio Oso Area 230 kV Voltage Support

Rio Oso, Atlantic, and Brighton Substations are located in Sutter, Placer, and Sacramento Counties respectively. These substations are connected via very long 230 kV and 115 kV transmission lines and serve over 700 MW of load between them using generation from North Valley and Sierra. During the summer peak period, the extremely long lines contribute to large voltage drops between the generation and the increasing loads. Figure 2.5.4-2 below shows the one-line diagram of the existing South of Rio Oso 230 kV system.

Figure 2.5.4-2: South of Rio Oso 230 kV Transmission System



This year's assessment identified the following voltage concerns in the Rio Oso 230 kV and Atlantic 60 kV systems:

- South of Rio Oso (Rio Oso, Atlantic, Brighton, Gold Hill) 230 kV low voltage (starting 2017 under category A);
- Atlantic 60 kV system low voltage (starting in 2013 under category A);
- Lockeford 230 kV low voltage (starting in 2012 under category B); and
- South of Rio Oso 230, 115 and 60 kV systems high voltage (existing under category A spring off-peak condition);

To mitigate these voltage concerns, PG&E submitted a project through the 2011 request window - the *Rio Oso 230 kV Voltage Support Project*, which proposes to install a +200/-175 MVar SVC at Rio Oso 230 kV and a 150 MVar shunt capacitor at Atlantic 230 kV.

The project is expected to cost between $35M and $45M and has an in-service date of May 2016. The ISO determined that this project is needed to mitigate the voltage issues identified in the area. In the interim, operating solutions such as changing the generator terminal voltage set points of the generators connected to the Rio Oso 230 kV and Atlantic 230/60 kV transformer bank tap settings will be used to mitigate these voltage concerns.

Two other PG&E proposed alternatives were considered.

Alternative 1: Atlantic-Placer Voltage Conversion Project

This alternative involves converting the 60 kV lines between Atlantic and Placer to 115 kV. This alternative is expected to cost between $50M and $60M and is not recommended because it does not address all of the area's high and low voltage issues

Alternative 2: Reactive Support at Rio Oso and Atlantic

This project involves installing 200 MVar of shunt capacitors and 175 MVar of shunt reactors at Rio Oso 230 kV bus as well as 150 MVar of shunt capacitors at Atlantic 230 kV Bus. It is not recommended because it provides a less accurate voltage regulation under both transient and steady state conditions as well as a slower and less smooth voltage control. Additionally, switching the shunt capacitors and reactors several times a day could result in decreased voltage quality for customers near Rio Oso. The project is expected to cost between $25 million to $35 million. The cost of this alternative will increase if a more sophisticated control system is needed for daily switching of the shunt capacitors and reactors.

TTS proposed a SVC project in the 2010 Request Window - Brighton 230 kV Reliability Solution - to address the low voltage concern at Brighton 230 kV bus. The ISO also considered this project as an alternative. It is not recommended because it does not mitigate the voltage concerns in the Rio Oso 230 kV and Atlantic 60 kV systems.

Stockton/Stanislaus Division Voltage Concern Mitigation

The ISO identified an existing low voltage at Lockeford 230 kV bus under a category B contingency condition. The *Rio Oso Area 230 kV Voltage Support Project*, discussed above, will also mitigate this low voltage concern at Lockeford. The project has an in-service date of May 2016. An operating action plan is in place to address this reliability concern in the interim.

The ISO also identified existing low voltages at Stagg and Eight Mile 230 kV buses under category C contingency conditions. The solution includes installing voltage support in the area. Because of permitting and lead times, the most feasible implementation timeline for this upgrade is 2015. An operating action plan is in place to address this reliability concern in the interim.

2.5.4.5 Key Conclusions

The 2011 reliability assessment of the PG&E Central Valley area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under normal, Categories B and category C contingency conditions. Also, one category C contingency resulted in the power flow divergence, indicating potential area-wide voltage collapse.

The problems identified in this 2011-2012 assessment are very similar to those found in last year's assessment. Four new projects were approved in the 2011 Transmission Plan, and those projects eliminated one normal and five category B overloads identified in last year's assessment. To address the identified thermal overloads and low voltage concerns, the ISO proposed a total of 14 transmission solutions and received two transmission project proposals through the Request Window. These two Request Window projects address more than one ISO-proposed solution. They are:

- *New Drum-Placer 115 kV line project*
- *Rio Oso Area 230 kV voltage support*

The ISO has determined that the Rio Oso Area 230 kV Voltage Support project is needed. The ISO continues to work with PG&E on the alternative assessment for the Drum-Placer 115kV line project. If completed in time, it will be updated in the final plan. If the assessment is not completed in time, it will be finalize it in the 2012/2013 planning cycle.

2.5.5 Greater Bay Area

2.5.5.1 Area Description

The Greater Bay Area (or Bay Area) is at the center of PG&E's service territory. This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties as shown in the adjacent illustration. For ease of conducting the performance evaluation, the Greater Bay Area is divided into three sub-areas: East Bay, South Bay and San Francisco-Peninsula.

The East Bay sub-area includes cities in Alameda and Contra Costa Counties. Some major cities are Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricity customers.

The South Bay sub-area covers approximately 1,500 square miles and includes the Santa Clara County. Some major cities are San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions, and the City of Santa Clara. Generation units within this sub-area include Calpine's Metcalf Energy Center, Los Esteros Energy Center, Gilroy Units, and SVP's Donald Von Raesfeld power plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations.

Finally, the San Francisco-Peninsula sub-area includes the San Francisco and San Mateo Counties. These counties comprise the cities of San Francisco, San Bruno, San Mateo, Redwood City, and Palo Alto. The San Francisco-Peninsula area presently relies on transmission line import capabilities, including the new Trans Bay cable, to serve its electricity demand. Electric power is imported from Pittsburg, East Shore, Tesla, Newark and Monta Vista substations to support the sub-area loads.

The *Trans Bay Cable Project* became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The project employs voltage source converter technology, which will transmit real power from the Pittsburg 230 kV substation in the City of Pittsburg to the Potrero 115 kV substation in the city and county of San Francisco.

In addition, the re-cabling of the Martin-Bayshore-Potrero lines (A-H-W #1 and A-H-W #2 115 kV cable), has replaced the two existing 115 kV cables between Martin-Bayshore-Potrero with new cables and resulted in increased ratings on these facilities. The new ratings provided by this project will increase transmission capacity between Martin-Bayshore-Potrero and relieve congestion.

The new major capacity projects include reconductoring of the East Shore-Dumbarton 115 kV line and East Shore-San Mateo 230kV line and replacement of the 230/115 kV transmission at the East Shore substation. Last year, the generation was modeled off-line. With the approved permit confirmed this year, it is now being modeled in 2020.

2.5.5.2 Area-Specific Assumptions and System Conditions

The Greater Bay area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured website provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology to the Greater Bay area study are provided below in this section.

Generation

Table 2.5.5-1 lists major generating plants that were modeled in the base cases for the Greater Bay Area analysis.

Table 2.5.5-1: Generators in the Greater Bay Area

Power Plant Name	Maximum Capacity (MW)
Alameda Gas Turbines	51
Calpine Gilroy I	182
Contra Costa Power Plant	680
Crockett Co-Generation	243
Delta Energy Center	965
High Winds, LLC	162
Los Esteros Critical Energy Facility	242
Los Medanos Energy Center	678
Metcalf Energy Center	575
Moss Landing Power Plant	1,500
Oakland C Gas Turbines	165
Donald Von Raesfeld Power Plant	182
Pittsburg Power Plant	1,360
Riverview Energy Center	61
Ox Mountain	13
United Cogen	30
Gateway Generating Station	599
Russell City Energy Center	614

Load Forecast

Loads within the Greater Bay Area reflect a coincident peak load for 1-in-10-year heat wave conditions. Table 2.5.5-2 shows the area load levels modeled for each of the PG&E local area studies, including the Greater Bay Area.

Table 2.5.5-2: Summer peak load forecasts for Greater Bay Area assessment

1- in- 10 Year Heat Wave Non-simultaneous Load Forecast						
Summer Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
EAST BAY	951	963	971	978	985	1,034
DIABLO	1,640	1,654	1,664	1,679	1,693	1,773
SAN FRANCISCO	973	981	988	997	1,007	1,058
PENINSULA	992	1,009	1,023	1,033	1,045	1,113
MISSION	1,276	1,291	1,230	1,312	1,324	1,425
DE ANZA	976	1,005	1,031	1,050	1,067	1,147
SAN JOSE	1,847	1,873	1,893	1,926	1,946	2,096

2.5.5.3 Study Results and Discussion

A summary of the study results of facilities in the Greater Bay area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions
No facilities were identified with thermal overload under the category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)
Fifteen facilities were identified with thermal overloads.

TPL 003: System Performance Following Loss of Two or More BES Elements
Numerous facilities were identified with thermal overloads or low voltage concerns.

Appendix A documents the thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

2.5.5.4 Recommended Solutions

Based on this year's reliability assessment results of the Greater Bay area, the ISO initially recommended solutions to address system performance results for the facilities that did not meet the thermal and voltage performance requirements under Categories A (normal), B and C contingency conditions. The ISO then evaluated the initial recommended solutions as well as submissions made through the Request Window process.

Following is a discussion of the ISO's analysis and the projects that were determined to be needed to address thermal and voltage performance requirements. This includes information about the expected in-service dates of the mitigation projects and plans that are designed to achieve the required system performance over the planning horizon.

2.5.5.4.1 Thermal Overload Mitigations

San Francisco Division
The Trans Bay cable and re-cabling projects of the A-H-W #1 and #2 115 kV cables were completed in 2011.

No overloads were found under normal operating conditions.

Potrero-Mission (AX) 115 kV Cable Overload

This overload would be caused by an outage of the Potrero-Larken #2 (AY-2) 115 kV cable during 2011 to 2021 summer peak conditions if the Trans Bay cable is at its full capacity of 400 MW. Reducing the Trans Bay cable transfer into San Francisco (with the existing automatic Trans Bay Cable DC Runback Scheme) to the minimum of 210 MW will reduce the flow on the Potrero-Mission (AX) 115 kV cable below its emergency rating.

Potrero-Larkin #1 (AY-2) 115 kV Cable Overload

This overload would be caused by the following category C contingencies:

- Potrero-Larkin #1 (AY-1) 115kV Cable and Potrero-Mission (AX) 115kV Cable
- Potrero-Mission (AX) 115kV Cable and Hunters Point-Mission #1 (PX-1) 115kV
- Potrero-Mission (AX) 115kV Cable and Potrero-Hunters Point (AP-1) 115kV Cable
- Potrero 115kV Bus 1D

The ISO recommends the following mitigation procedure for each of the above overloads:

- Develop an operating procedure to transfer loads among relevant substations and/or reduce Trans Bay cable output upon detection of an overload and the contingencies that are causing it.
- If the overload still exists, drop a calculated amount of load either manually or through an SPS. For manual load dropping, short-term emergency (STE) ratings must be developed and the line loading must be within STE ratings.

Loss of Embarcadero Load

The Embarcadero substation is supplied by two 230 kV underground cables from Martin substation with the 230 kV cables at the Embarcadero substation connected in a simple bus arrangement. The Category C contingency of the loss of the two Embarcadero-Martin 230 kV cables or a 230 kV breaker failure in the Embarcadero substation will result in the loss of the load served at the Embarcadero substation. PG&E has identified that transferring of the load served from Embarcadero to other stations through the distribution system is limited during an outage of both 230 kV cables. When one of the 230 kV cables is out of service due to a failure or for maintenance or to allow for work by other underground linear facilities in the area the loss of the other cable could potentially result in a lengthy outage to the area due to the restoration time required to bring either of the cables back in-service. Planned outages to accommodate other underground linear facility construction are expected to grow in the future. While the likelihood of the simultaneous loss of both circuits is low, the consequences of the outage are severe and require mitigation.

PG&E identified to the ISO that PG&E will be rebuilding the Embarcadero substation. The 230 kV breaker configuration at the station will be converted to a breaker and a half arrangement as a part of the substation rebuild project by PG&E and are estimating to be complete by 2016. PG&E submitted the Embarcadero-Potrero 230 kV cable project in the request window to address potential loss of load at the Embarcadero substation in the event of the loss of both 230 kV cables. The project will provide an additional supply to the Embarcadero substation from Potrero substation.

Due to the Embarcadero load being connected to the transmission system by only the Martin-Embarcadero 230 kV cables, the alternatives to provide reinforcement to Embarcadero station were limited to a new connection to the transmission system or to the distribution system. In considering transmission alternatives, it was determined from a reliability perspective an alternate supply source other than another circuit from the Martin substation would be preferred. In addition, as the only high voltage bus at Embarcadero is 230 kV, the supply should be at 230 kV. The reinforcement of the distribution system to address the identified reliability and load requirements at Embarcadero was deemed to be unfeasible as the existing distribution system is only capable of supplying approximately 10 MW of the existing Embarcadero load from other substations.

The ISO has determined that this project is needed to address the reliability requirements of the area and is expected to be in-service in 2015. In the interim the ISO will work with PG&E to ensure operations procedures are in place.

Peninsula Division

No overloads were found under normal operating conditions.

Jefferson-Stanford 60 kV Line #1 Overload
This overload would be caused by a loss of the Cooley Landing-Stanford 60 kV line with the Cardinal Co-Gen off-line at the expected load level of summer 2012. ISO has approved a project to build a new Jefferson-Stanford #2 60 kV line. This is scheduled to be completed by 2014. Reconductoring the existing line is not feasible because of logistical constraints.

Ravenswood-Palo Alto 115 kV Line #1 Overload
This overload would be caused by a bus fault at the Ravenswood 115 kV Substation Bus 2E or the loss of the Ravenswood-Palo Alto 115 kV #2 line and the Ravenswood-Cooley Landing 115 kV #2 line at the expected load level of summer 2012. The ISO recommends developing a short-term emergency rating and operating procedures before summer 2012 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO is currently working closely with the City of Palo Alto, PG&E and other stakeholders to evaluate a proposal that best addresses the reliability issues in the most cost-effective manner. Further analysis of the alternatives will be carried out in the 2012/2013 planning cycle.

Ravenswood-Palo Alto 115 kV Line #2 Overload
This overload would be caused by loss of two transmission lines on separate towers: either the Ravenswood-Palo Alto #1 and Cooley Landing-Palo Alto 115 kV lines; or the combination of Ravenswood-Cooley Landing #2 115 kV line and Ravenswood-Palo Alto #1 115 kV line at the expected load level of summer 2012. The ISO recommends developing a short-term emergency rating and operating procedures before summer 2012 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO is currently working closely with the City of Palo Alto, PG&E and other stakeholders to evaluate a proposal that best addresses the reliability issues in

the most cost-effective manner. Further analysis of the alternatives will be carried out in the 2012/2013 planning cycle.

Cooley Landing-Palo Alto 115 kV Line #1 Overload

This overload would be caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at the expected load level of summer 2012. The ISO recommends re-rating the overloaded line and developing the STE rating. The ISO recommends developing a short-term emergency rating and operating procedures before summer 2012 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO is currently working closely with the City of Palo Alto, PG&E and other stakeholders to evaluate a proposal that best addresses the reliability issues in the most cost-effective manner. Further analysis of the alternatives will be carried out in the 2012/2013 planning cycle.

Ravenswood-Cooley Landing 115 kV Line #2 Overload

This overload would be caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at the expected load level of summer 2012. The ISO recommends re-rating the overloaded line and developing the STE rating. The ISO recommends developing a short-term emergency rating and operating procedures before summer 2012 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO is currently working closely with the City of Palo Alto, PG&E and other stakeholders to evaluate a proposal that best addresses the reliability issues in the most cost-effective manner. Further analysis of the alternatives will be carried out in the 2012/2013 planning cycle.

Ravenswood-San Mateo 115 kV Line #1 Overload

This overload would be caused by loss of a double circuit tower line, Ravenswood-San Mateo 230 kV line #1 and #2 at the expected load level of summer 2012. The ISO recommends developing operating procedures before summer 2012 to drop a calculated amount of load either manually or through the existing South of San Mateo SPS to mitigate the overload.

San Mateo-Belmont 115 kV Line #1 Overload

This overload would be caused by loss of a double circuit tower line: either the Ravenswood-Bair 115 kV line #1 and #2 at the expected load level of summer 2020, or the combined loss of Ravenswood 230/115 kV bank #1 and #2 at the expected load level of summer 2013. The ISO recommends re-rating the overloaded line and developing the STE rating. If re-rating is not applicable or it does not eliminate the overload, the ISO recommends developing operating procedures before summer 2012 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair 115/60 Transformer #1 Overload

This overload would be caused by loss of the Ravenswood-Cooley Landing #1 115 kV line and the Cooley Landing 115/60 kV transformers #2 at the expected load level of summer 2012. The ISO recommends replacing a transformer or dropping a calculated amount of load to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair-Cooley Landing 60 kV Line #1 Overload
This overload would be caused by loss of the Bair-Cooley Landing #2 60 kV line and the Bair 115/60 kV transformers #1 at the expected load level of summer 2021. ISO recommends dropping a calculated amount of load to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair-Cooley Landing 60 kV Line #2 Overload
This overload would be caused by loss of the San Mateo-Bair 60 kV line and the Bair 115/60 kV transformers #1 at the expected load level of summer 2013. The ISO recommends load curtailment to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

San Mateo 230/115 Transformer #5 Overload
This overload would be caused by loss of San Mateo 230/115 kV transformers #6 and #7 at the expected load level of summer 2013. Since overloading is less than 10 percent, the ISO recommends re-rating the overloaded transformer and developing STE ratings. If re-rating is not achievable or does not relieve the overload, the ISO recommends adding cooling fans to increase transformer capacity. If cooling fans are not feasible, load curtailment may be required to relieve the overload.

San Mateo 230/115 Transformer #6 Overload
This overload would be caused by loss of San Mateo 230/115 kV transformers #5 and #7 at the expected load level of summer 2013. Since overloading is less than 10 percent, the ISO recommends re-rating the overloaded transformer and developing STE ratings. If re-rating is not achievable or does not relieve the overload, the ISO recommends adding cooling fans to increase transformer capacity. If cooling fans are not feasible, load curtailment may be required to relieve the overload.

San Mateo 230/115 Transformer #7 Overload
This overload would be caused by loss of San Mateo 230/115 kV transformers #5 and #6 at the expected load level of summer 2013. Since overloading is less than 10 percent, the ISO recommends re-rating the overloaded transformer and developing STE ratings. If re-rating is not achievable or does not relieve the overload, the ISO recommends adding cooling fans to increase transformer capacity. If cooling fans are not feasible, load curtailment may be required to relieve the overload.

East Bay Division

No overloads were found under normal operating conditions (category A)

Oleum-North Tower-Christie 115 kV Line Overload
This overload would be caused by loss of a Christie-Sobrante 115 kV line and Union CH Generation at the expected load level of summer 2014. The ISO is currently working closely with PG&E to implement a comprehensive solution to address the overloads in the area and to ensure that the solution is the most cost-effective among all other alternatives with comparable reliability.

The ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV Line. The project will effectively remove North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line. The scope will include utilizing an idle line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV Line and reconfiguring some of the five lines with a geographical crossing at Martinez JCT.

Oleum-Martinez 115 kV Line Overload

This overload would be caused by loss of the Martinez-Sobrante 115 kV line and Gateway Generation at the expected load level of summer 2021. The ISO has been working closely with PG&E to implement a comprehensive solution to address the overloads in the area and to ensure that the solution is the most cost-effective among all other alternatives with comparable reliability.

The ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV Line. The project will effectively remove North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line. The scope will include utilizing an idle line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV Line and reconfiguring some of the five lines with a geographical crossing at Martinez JCT.

Oleum-North Tower-Christie 115 kV Line Overload

This overload would be caused by the following Category B and C contingencies:

- Christie-Sobrante 115 kV line and Union Chemical offline;
- Christie-Sobrante 115 kV line and GWF #5 Generation offline; or
- Christie-Sobrante 115 kV and Martinez-Sobrante 115 kV lines;

The ISO has been working closely with PG&E to implement a comprehensive solution to address the overloads in the area and to ensure that the solution is the most cost-effective among all other alternatives with comparable reliability.

The ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV Line. The project will effectively remove North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line. The scope will include utilizing an idle line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV Line and reconfiguring some of the five lines with a geographical crossing at Martinez JCT.

Christie-Sobrante 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line, Sobrante-G #1 and #2 115 kV lines at the expected load level of summer 2021. The ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV line. The project will effectively remove North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line. The scope will include utilizing an idle line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV line and reconfiguring some of the five lines with a geographical crossing at Martinez JCT.

Oleum - Martinez 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line; Sobrante-G #1 and #2 115 kV lines at the expected load level of summer 2014. The ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV line. The project will effectively remove North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line. The scope will include utilizing an idle line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV line and reconfiguring some of the five lines with a geographical crossing at Martinez JCT.

Diablo Division

No overloads were found under normal operating conditions (category A)

Contra Costa-Moraga 230 kV line #1 Overload

This overload would be caused by a line outage of Contra Costa-Moraga 230 kV line #2 and DEC offline at the expected load level of summer 2012. The ISO has already approved reconductoring the line. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Contra Costa-Moraga 230 kV line #2 Overload

This overload would be caused by a line outage of Contra Costa-Moraga 230 kV line #1 and DEC offline at the expected load level of summer 2012. The ISO has already approved reconductoring the line. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Moraga-Oakland J 115 kV Line Overload

This overload would be caused by a bus fault at the San Leandro 115 kV bus D at the expected load level of summer 2012. As an interim solution, the ISO recommends using an SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 Transmission Plan as a cost-effective solution for the reliability problems found in this area.

As the ISO has been pursuing the Oakland Area Long Term plan with PG&E to address the long-term transmission needs in the East Bay, the ISO has approved the project to reconductor the East Shore-Grant 115 kV #1 and #2 lines, reconductor the Grant-Oakland J 115 kV line, and establish a new connection at Oakland J Substation.

The project will have Edes to be normally served via Grant. In addition, this project protects against the complete loss of PG&E's Oakland J Substation and the City of Alameda's Jenny Substation during a double circuit tower line outage event.

Moraga-Lakewood 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying the Lakewood-Clayton and Lakewood-Meadow Lane-Clayton 115 kV lines at the expected load level of summer 2012. The ISO recommends using an SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Moraga-San Leandro 115 kV Line #1 Overload

This overload would be caused by loss of either the Moraga-San Leandro 115 kV line #2 and #3 at the expected load level of summer 2012 or the Moraga-Oakland J 115 kV line and the Moraga-San Leandro 115 kV line #3 at the expected load level of summer 2012. As an interim solution, the ISO recommend incorporating SPS or RAS into the operating procedures to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS is in place on time.

As the ISO has been pursuing the Oakland Area Long Term plan with PG&E to address the long-term transmission needs in the East Bay, the ISO has approved the project to reconductor the East Shore-Grant 115 kV #1 and #2 lines, reconductor the Grant-Oakland J 115 kV line, and establish a new connection at Oakland J Substation.

The project will have Edes is to be normally served via Grant to alleviate the loading on Moraga-San Leandro 115 kV line #1.

Moraga-San Leandro 115 kV Line #2 Overload
This overload would be caused by loss of either the Moraga-San Leandro 115 kV line #1 and #3 at the expected load level of summer 2012 or the Moraga-Oakland J 115 kV line and the Moraga-San Leandro 115 kV line #3 at the expected load level of summer 2012.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 Transmission Plan. As the ISO has been pursuing the Oakland Area Long Term plan with PGAE to address the long-term transmission needs in the East Bay, the ISO has approved the project to reconductor the East Shore-Grant 115 kV #1 and #2 lines, reconductor the Grant-Oakland J 115 kV line, and establish a new connection at Oakland J Substation

The project will have Edes to be normally served via Grant to alleviate the loading on Moraga-San Leandro 115 kV line #2.

Moraga-San Leandro 115 kV Line #3 Overload
This overload would be caused by loss of either the Moraga-San Leandro 115 kV line #1 and #2 at the expected load level of summer 2012 or the Moraga-Oakland J 115 kV line and the Moraga-San Leandro 115 kV line #2 at the expected load level of summer 2015.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 Transmission Plan. As the ISO has been pursuing the Oakland Area Long Term plan with PG&E to address the long-term transmission needs in the East Bay, the ISO has approved the project to reconductor the East Shore-Grant 115 kV #1 and #2 lines, reconductor the Grant-Oakland J 115 kV Line, and establish a new connection at Oakland J Substation

The project will have Edes to be normally served via Grant to alleviate the loading on Moraga-San Leandro 115 kV Line #3.

Mission Division

No overloads were found under normal operating conditions (category A).

No overloads were found under category B contingency conditions.

Newark-Ames 115 kV Line #1 Overload
This overload would be caused by double line contingencies of the Newark-Ravenswood 230 kV line and the Tesla-Ravenswood 230 kV line at the expected load level of summer 2012. Once the Russell City Generation is on line, the thermal overload will no longer be an issue. In the meantime, the ISO recommends incorporating SPS or RAS into the operating procedures to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames 115 kV Line #2 Overload

This overload would be caused by double line contingencies of the Newark-Ravenswood 230 kV line and the Tesla-Ravenswood 230 kV line at the expected load level of summer 2012. Once the Russell City Generation is on line, the thermal overload will no longer be an issue. In the meantime, the ISO recommends incorporating SPS or RAS into the operating procedures to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames 115 kV Line #3 Overload

This overload would be caused by double line contingencies of the Newark-Ravenswood 230 kV line and the Tesla-Ravenswood 230 kV line at the expected load level of summer 2012. Once the Russell City Generation is on line, the thermal overload will no longer be an issue. In the meantime, the ISO recommends incorporating SPS or RAS into the operating procedures to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames Distribution 115 kV Line Overload

This overload would be caused by double line contingencies of the Newark-Ravenswood 230 kV line and the Tesla-Ravenswood 230 kV line at the expected load level of summer 2012. Once the Russell City Generation is on line, the thermal overload will no longer be an issue. In the meantime, the ISO recommends incorporating SPS or RAS into the operating procedures to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Moraga-Castro Valley 230 kV Line Overload

This overload would be caused by the outage of either the Contra Costa-Las Positas 230 kV line and the Tesla-Newark #2 230 kV line at the expected load level of summer 2012 or the Contra Costa-Las Positas 230 kV line and Contra Costa-Lonetree 230 kV line at the expected load level of summer 2012. This is mitigated with the approved Moraga-Castro Valley 230 kV Capacity Project.

East Shore 230/115 kV Bank #1 Overload

This transformer overload would be caused by the outage of) the Dumbarton-Newark 115 kV line and the East Shore 230/115 kV bank #2 at the expected load level of summer 2013. There is a large increase in magnitude in the overload once the Russell City Generation is online. The ISO has approved the replacement of the bank and it is scheduled to be completed before the Russell City Generation.

East Shore 230/115 kV Bank #2 Overload

This transformer overload would be caused by the outage of the Dumbarton-Newark 115 kV line and the East Shore 230/115 kV bank #1 at the expected load level of summer 2013. The ISO has approved the replacement of the bank and it is scheduled to be completed before the Russell City Generation.

Grant-East Shore #1 115 kV Line Overload

This overload would be caused by an outage of the San Leandro-Oakland J 115 kV line and the Grant-East Shore #2 115 kV line at the expected load level of summer 2020. The ISO has approved the East Shore-Oakland J 115 kV Reconductor Project this year, which includes reconductoring the line as well.

Grant-East Shore #2 115 kV Line Overload

This overload would be caused by an outage of the San Leandro-Oakland J 115 kV line and the Grant-East Shore #2 115 kV line at the expected load level of summer 2020. The ISO has approved the East Shore-Oakland J 115 kV Reconductor Project this year, which includes reconductoring the line as well. East Shore-Dumbarton 115 kV Line Overload.

This overload would be caused by an outage of the Pittsburg-East Shore and the East Shore-San Mateo 230 kV lines at the expected load level of summer 2013. There is a large increase in magnitude in the overload once the Russell City Generation is on line. The ISO has approved the replacement of the line and it is scheduled to be completed before the Russell City Generation.

East Shore-Dumbarton 115 kV Line Overload

This overload would be caused by an outage of the Pittsburg-East Shore and the East Shore-San Mateo 230 kV lines at the expected load level of summer 2013. There is a large increase in magnitude in the overload once the Russell City Generation facility is on line. The ISO has approved the replacement of the line and it is scheduled to be completed before the Russell City Generation project.

Las Positas-Newark 230 kV Line Overload

This overload would be caused by an outage of the East Shore-San Mateo 230 kV and Pittsburg-San Mateo 230 kV lines at the expected load level of summer 2012. The ISO recommends mitigation by congestion management.

Castro Valley-Newark 230 kV Line Overload

This overload would be caused by an outage of the Contra Costa-Las Positas 230 kV line and the Tesla-Newark #2 230 kV line at the expected load level of summer 2012. The ISO recommends mitigation by congestion management.

San Jose Division

No overloads were found under normal operating conditions (category A)

Newark-Dixon Landing 115 KV Line Overload

This overload would be caused by an outage of the Piercy-Metcalf 115 kV line at the expected load level of summer 2012. The ISO has already approved the Evergreen Conversion Project scheduled to be completed by 2015 to resolve the overload. In the meantime, the ISO will work with PG&E to ensure that the interim operating procedure is in place on time.

Piercy-Metcalf 115kV Line Overload

This overload would be caused by an outage of the Newark-Dixon Landing 115 KV line at the expected load level of summer 2012. The ISO has already approved the Evergreen Conversion Project scheduled to be completed by 2015 to resolve the overload. In the meantime, the ISO will work with PG&E to ensure that the interim operating procedure is in place on time.

Monta Vista - Los Gatos 60 kV Line Overload

This overload would be caused by an outage of the Evergreen 115/60 kV bank #1 at the expected load level of summer 2012. The ISO has already approved the Monta Vista-Los Gatos-Evergreen reconductor project to resolve the overload. In the meantime, the ISO will work with PG&E to ensure that the interim operating procedure is in place on time.

Metcalf 230/115 kV Bank #1 Overload

This overload would be caused by an outage of the Metcalf 230/115 kV Bank #2 and the Metcalf 230/115 kV Bank #4 at the expected load level of summer 2021. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Metcalf 230/115 kV Bank #2 Overload

This overload would be caused by either an outage of the Metcalf 230/115 kV bank #1 and Metcalf 230/115 kV bank #3 at the expected load level of summer 2011 or the loss of Metcalf 230 kV Bus #1 D at the expected load level of summer 2021. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Metcalf 230/115 kV Bank #3 Overload

This overload would be caused by either an outage of the Metcalf 230/115 kV bank #2 and the Metcalf 230/115 kV bank #4 at the expected load level of summer 2021 or the loss of the Metcalf 230 kV Bus #1 D at the expected load level of summer 2021. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Metcalf 500/230 kV Bank #13 Overload

This overload would be caused by an outage of the Metcalf 500/230 kV bank #11 and #12 at the expected load level of summer 2013. The ISO recommends mitigation by congestion management.

Newark-Milpitas #2 115 kV Line Overload

This overload would be caused by an outage of the Newark-Milpitas #1 115 kV line and Swift-Metcalf 115 kV line at the expected load level of summer 2021. The ISO has already approved the Evergreen Conversion Project scheduled to be completed by 2015 to resolve the overload. In the meantime, the ISO will work with PG&E to ensure that the interim operating procedure is in place on time.

Metcalf-Morgan Hill 115 kV Line Overload

This overload would be caused by an outage of the Metcalf-Morgan Hill 115 kV line and the Llagas-Gilroy Foods 115 kV line at the expected load level of summer 2012. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Hicks-Metcalf 230 kV Line Overload

This overload would be caused by the outage of the Metcalf-Monta Vista #3 230 kV line and the Monta Vista-Coyote Switching Station 230 kV line at the expected load level of summer 2012. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Monta Vista-Hicks 230 kV Line Overload

This overload would be caused by an outage of the Metcalf-Monta Vista #3 230 kV line and the Monta Vista-Coyote Switching Station 230 kV line at the expected load level of summer 2012. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

De Anza Division

No overloads were found under normal operating conditions (category A).

Cooley Landing-Los Altos 60 kV Line Overload

This overload would be caused by loss of either Monta Vista-Los Altos 60 kV line or Monta Vista 230/60 kV bank #5 at the expected load level of summer 2021. The ISO has already approved the reconductoring project to resolve the overload.

Evergreen-Almaden 60 kV Line Overload

This overload would be caused by loss of Monta Vista 230/60 kV bank #5 at the expected load level of summer 2012. The overload is caused by closing the normally-open switch at Los Gatos. The ISO recommends maintaining the present configuration until further information is available to warrant an alternate solution.

Saratoga-Vasona 230 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying the Metcalf-Monta Vista #3 and the Monta Vista-Coyote Switching Station 230 kV lines at the expected load level of summer 2021. In the interim the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

2.5.5.4.2 Voltage Concern Mitigation

Four substations were identified in the Diablo Area as not meeting the required voltage performance under category B contingency conditions. The ISO recommends reactive support.

Three substations were identified in the East Bay and five substations were identified in the Diablo Area as not meeting the required voltage performances under category C contingency conditions. The ISO recommends reactive support.

There are no substations identified with high voltages.

2.5.5.5 Key Conclusions

The previous 2011 reliability assessment of the PG&E Greater Bay Area has identified several reliability concerns. These concerns consist of thermal overloads under both Categories B and C contingency conditions. The ISO has been exploring capital projects that mitigate these reliability concerns in the long term and in the most cost-effective manner.

This year, the ISO has approved the project to loop North Tower Substation into the Martinez-Sobrante 115 kV line. The project is found to be very cost-effective as it utilizes one idle line and one under-utilized line sharing a transmission tower with the Oleum-North Tower-Christie 115 kV line and effectively removes North Tower from the heavily loaded Oleum-North Tower-Christie 115 kV line.

Furthermore, the project helps alleviate the potential overload caused by the DCTL or N-1-1 contingency south of the Sobrante area.

Additionally, the ISO has approved the East Shore–Oakland "J" 115 kV Reconductor project. This project mitigates the overload caused by category B and C contingencies in the Moraga and San Leandro areas. It also provides numerous side benefits in the area. By connecting the East Shore 115 kV bus to the Moraga 115 kV bus through the Oakland J and San Leandro 115 kV buses, the project will also prevent congestion and thermal overload in the East Shore Area after the Russell City Generation is on line.

Two ongoing projects are actively under review to address the reliability concern with the City of Palo Alto and the Downtown of San Francisco load.

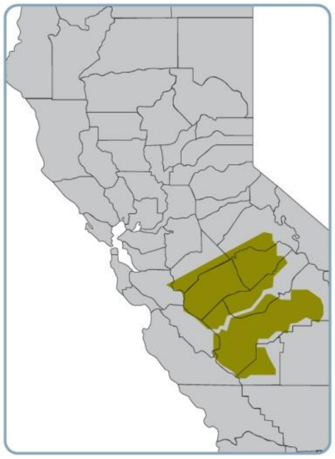
To address the reliability concern at the City of Palo Alto, the ISO has facilitated discussions between PG&E, Palo Alto and other concerned stakeholders. The ISO has provided technical support to the city for their parallel evaluation. The ISO has identified the issues that are critical to the city's proposal and is ready to evaluate the multiple proposals submitted once the corresponding pertinent information becomes available.

To address the reliability concern in supply to the downtown San Francisco area due to breaker failure in the Embarcadero substation or both of the Martin-Embarcadero 230 kV cables the ISO has determined that an additional 230 kV supply to the Embarcadero substation is required. The ISO has therefore identified the Embarcadero-Potrero 230 kV cable project submitted by PG&E in the request window is needed. The 230 kV cable from Potrero will terminate into the rebuilt 230 kV breaker configuration that is being rebuilt as a part of the Embarcadero substation rebuild that PG&E will be undertaking.

2.5.6 Greater Fresno Area

2.5.6.1 Area Description

The Greater Fresno Area is located in the central to southern PG&E service territory. This area includes Madera, Mariposa, Merced and Kings Counties, which are located within the San Joaquin Valley Region. The adjacent figure depicts the geographical location of the Fresno area.



The Greater Fresno area electric transmission system is composed of 70 kV, 115 kV and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area hydro generation (the largest of which is Helms Pump Storage Plant), a number of market facilities and few qualifying facilities. It is supplemented by transmission imports from the North Valley and the 500 kV along the west and south parts of the Valley. The Greater Fresno area is composed of two primary load pockets, one being the Yosemite area in the northwest portion of the shaded region in the adjacent figure. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by 14 transmission circuits. These consist of ten 230 kV lines; one 230/115 kV bank; two 230/70 kV banks; and one 70 kV line, which are served from the Gates substation in the south, Moss Landing in the West, Los Banos in the Northwest, Bellota in the Northeast, and Templeton in the Southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season but it also experiences high loading because of the potential of 900 MW of pump load at Helms during off-peak. Load forecasts indicate the Greater Fresno area should reach its summer peak demand of approximately 3,650 MW and summer off-peak load exceeding 1,960 MW (excluding the Helms pump load) by 2021 assuming load is increasing at a rate of 42 MW per year. This area has a maximum capacity of about 3,405 MW of local generation. The largest generation facility within the area is the Helms plant, with 1,212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer-peak and off-peak conditions that reflect different operating conditions of Helms.

2.5.6.2 Area-Specific Assumptions and System Conditions

The Greater Fresno area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured website provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology that applied to the Fresno area study are provided below.

Generation

Generation resources in the Greater Fresno area consist of market, QFs and self-generating units. Table 2.5.6-1 lists all generating plants in the Greater Fresno and Yosemite areas modeled in the study.

Table 2.5.6-1: Generation units in the Greater Fresno peak analysis

Plant Name	Max Capacity (MW)
Fresno Cogen-Agrico	79.9
Balch 1 PH	31
Mendota Biomass Power	25
Balch 2 PH	107
Chow 2 Peaker Plant	52.5
Chevron USA (Coalinga)	25
Chow II Biomass to Energy	12.5
Coalinga Cogeneration Company	46
CalPeak Power – Panoche LLC	49
Dinuba Generation Project	13.5
El Nido Biomass to Energy	12.5
Exchequer Hydro	94.5
Fresno Waste Water	9
Friant Dam	27.3
GWF Henrietta Peaker Plant	109.6
HEP Peaker Plant Aggregate	102
Hanford L.P.	23
Haas PH Unit 1 & 2 Aggregate	146.2
Helms Pump-Gen	1,212
Herndon Synch Condenser	0
J.R. Wood	10.8
Kerkhoff PH 1	32.8
Kerkhoff PH 2	142
Kingsburg Cogen	34.5
Kings River Hydro	51.5
Kings River Conservation District	112
Madera	28.7
McCall Synch Condensers	0
Mc Swain Hydro	10
Merced Falls	4
O'Neill Pump-Gen	11
Panoche Energy Center	410
Pine Flat Hydro	189.9
Sanger Cogen	38
San Joaquin 2	3.2
San Joaquin 3	4.2
Rio Bravo Fresno (AKA Ultrapower)	26.5
Wellhead Power Gates, LLC	49
Wellhead Power Panoche, LLC	49
Wishon/San Joaquin #1-A Aggregate	20.4
Generation Total	**3405**

Load Forecast

Loads within the Fresno and Yosemite area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.5.6-2 shows the substation loads assumed in these studies under summer peak and off-peak* conditions. These tables also show loads modeled for neighboring local areas in the PG&E system in the Fresno and Yosemite area assessment.

Table 2.5.6-2: Load forecasts modeled in Fresno and Yosemite area assessment

Summer Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
YOSEMITE	861	870	877	887	915	980
FRESNO	2,246	2,277	2300	2,331	2,355	2,540

Note: *Fresno off-peak load is 51% of the peak load.

2.5.6.3 Study Results and Discussion

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one facility was identified with thermal overloads. No facilities were identified with low voltage concerns. Twenty-four facilities were identified with high voltage concerns under the category A performance requirement.

For the summer off-peak cases, no facilities were identified with thermal overloads and no facilities were identified with low voltage concerns but there were 41 off-peak high voltage concerns under the category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)

For the summer peak cases, five facilities were identified with thermal overloads. Three facilities were identified with low voltage concerns under the category B performance requirement.

For the summer off-peak cases, one facility was identified with thermal overloads. No facilities were identified with low voltage concerns under the category B performance requirement. The details of the overloads, contingencies and the mitigation are listed in appendix A.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, 80 facilities were identified with thermal overloads. 57 facilities were identified with low voltage concerns and 36 facilities were identified with voltage deviation concerns under the category C performance requirement. The details of the overloads, contingencies and the mitigation are listed in Appendix A.

For the summer off-peak cases, six facilities were identified with thermal overloads. Forty-one facilities were identified with high voltage concerns, and no facilities were identified with low voltage concerns under the category C performance requirement. The details of the overloads, contingencies and the mitigation are listed in Appendix A.

2.5.6.4 Recommended Solutions

Based on this year's reliability assessment results of the Fresno local area, the ISO recommended solutions that address system performance results that did not meet the thermal and voltage performance requirements under Categories A, B and C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- reinforcing or upgrading the system to avoid area wide voltage collapse;
- installing new and additional transformer banks;
- building new transmission lines;
- converting low voltage lines to higher ones;
- re-rating facilities, reconductoring, network looping and reconfiguring stations; and
- installing shunt capacitor banks for voltage support.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. It provides information about the expected in-service dates of the mitigation projects and plans.

2.5.6.4.1 Thermal Overload Mitigations

The thermal overloads for summer peak conditions are discussed below.

Helm-Kerman 70 kV Line

Helm-Kerman 70 kV line was identified as 108 percent overloaded under category A conditions in the 2021 summer peak case. The line becomes overloaded between 2016 and 2021. Accordingly, PG&E submitted a project in this planning cycle to address the overload. The scope of the project is to reconductor 1.9 miles of the line with 715 All Aluminum Conductor AAC. The in-service date of the project is 2016, which will be in time to address the expected overload on this line. The ISO determined that this project is needed to meet reliability concerns.

Reedley-Orosi and Dinuba-Orosi 70 kV Lines

The lines between the Reedley and Orosi substations were overloaded by 109 percent under category B conditions in the 2021 summer peak case. The line becomes overloaded between 2016 and 2021. Additionally, the lines between Dinuba and Orosi substations were overloaded by 110 percent under category B conditions in the 2021 summer peak case. There were also some thermal overloads under category C conditions. The mitigation plan is to replace the limiting equipment on the Reedley-Orosi 70 kV line to achieve the full conductor rating of 715.5 AAC and to reconductor 9 miles of Dinuba-Orosi 70 kV line from Dinuba to Stone Corral Junction with 715.5 AAC. Accordingly, the PG&E Reedley 70 kV Reinforcement Project was proposed through the 2011 Request Window. The ISO determined that this project is needed to meet reliability concerns.

Kearney 230/70 Transformer bank #2

The bank becomes overloaded between 2016 and 2021 under category B conditions in the summer peak case. PG&E has a customer reliability project already in place to mitigate this overload.

Panoche-Oroloma 115 kV Line

The section between Panoche and Hammonds substation on Panoche-Oroloma 115 kV line was identified as overloaded under category B and C conditions in 2021 summer peak cases to 102 percent and 126 percent, respectively. The mitigation plan proposed by PG&E is to reconductor the 16.8 mile long limiting section and to replace terminal equipment as necessary to achieve the required rating. With the need for the reinforcement not until 2021 and there being sufficient lead time based upon the in-service date for the project provided by PG&E 2016, the ISO is not identifying the Panoche – Oroloma 115 kV Line project as needed in this plan and will continue to monitor the area's needs in future planning assessments

Gregg- Ashlan 230 kV Lines

Gregg-Ashlan 230 kV line was identified as overloaded up to 173 percent under category C5 conditions in the 2012 to 2019 summer peak cases. The ISO has already approved the Gregg-Ashlan 230kV reconductor project in an earlier transmission planning cycle. In the interim (between 2012 and 2018), it is recommended that an operating procedure be developed (with an in-service date on or before June 1, 2012) to address any potential reliability concern. The ISO will work with PG&E to ensure that the operating procedure is in place on time.

Northern Fresno Area 115 kV Reinforcement

This year's analysis resulted in identification of some new thermal and voltage issues under category C conditions starting in 2012. PG&E has proposed the Northern Fresno 115 kV Area Reinforcement project with an in-service date in 2018. The ISO is not identifying the project as needed in this plan and will continue to assess the reliability needs in future planning assessments for this area. The ISO will work with PG&E to ensure that the operating action plans are to address the category C reliability issues identified in this study.

Wilson 115 kV Area

Several lines, such as Wilson-Le Grand 115 kV line, Legrand-Dairyland and Wilson-Oroloma were identified as overloaded up to 161 percent under category C (N-1-1) conditions until 2015.

The ISO approved the long-term Wilson 115 kV Area Reinforcement project in 2010, which will mitigate these problems. In the interim (between 2012 and 2015), Mitigation will be provided by the Atwater SPS and operator switching actions following the first contingency in preparation for the next outage. The thermal overloads for the summer off-peak conditions are discussed below.

Gates-Panoche #1 and Gates-Panoche #2 230 kV Lines

The Gates-Panoche #1 and Gates-Panoche #2 lines were identified as overloaded under NERC category C5 (DCTL) conditions starting in 2012 summer off-peak to a maximum of 112 percent for each line. Accordingly, PG&E submitted the Gates-

Panoche #1 and Gates-Panoche #2 reconductor project. Since this is an off-peak problem, the ISO has proposed congestion management as an effective mitigation in the interim. If required, this project will be analyzed again in subsequent planning cycles.

Gates-Mccall 230 kV Line

The Gates-Mccall 230 kV line was identified as overloaded under category C conditions starting in 2012. The ISO already approved the long-term *Fresno Reliability Transmission Plan* in an earlier planning cycle. In the interim, congestion management will resolve this off-peak issue.

2.5.6.4.2 Voltage Concern Mitigations

Borden 230 kV Voltage Support Project

This year's analysis identified a couple of voltage deviation issues in the Borden area under category B conditions beginning in 2012. Additionally, some low voltage issues were identified beginning in 2016 under category B conditions. Low voltage issues under category C conditions were identified beginning in 2012. Accordingly, PG&E submitted the Borden 230 kV voltage support project. The scope of this project is to install 200 MVar of reactive support on the 230 kV Borden bus and loop the existing Wilson-Gregg 230 kV line to the Borden Substation. The looping supersedes the load drop option for category C problems in terms of increased load serving capability of the system. The ISO determined that this project is needed to meet reliability concerns. The ISO will work with PG&E to ensure that the operating procedures are in place in the interim.

Oakhurst and Coarsegold UVLS project

This year's analysis identified a couple of low voltage conditions in the Oakhurst area under category C conditions starting in 2012. Additionally, some voltage deviation issues were identified beginning in 2012. A couple of new thermal violations under category C conditions were identified beginning in 2021. Accordingly, PG&E proposed the Oakhurst and Coarsegold UVLS project. The scope of the project is to develop a UVLS scheme that will constantly monitor the voltage on the Coarsegold and Oakhurst substations and will first shed load at Oakhurst and subsequently shed load at Coarsegold if the voltage does not improve. The ISO determined that this project is needed to mitigate reliability concerns. The ISO will work with PG&E to ensure that the operating procedures are in place in the interim.

North Merced-Cressey 115 kV Line

The ISO had approved the Wilson 115 kV area reinforcement project last year, which resolved the voltage collapse and other thermal issues in the area. Low voltage and voltage deviation conditions were identified starting in 2015. Additionally, some new category C thermal overloads were identified because of the changes in the conforming load power factor assumption differences between this year's and last year's base cases. Accordingly, PG&E submitted the Cressey-North Merced 115 kV line project. This project has a benefit-cost ratio (BCR) of 1.03 and was more cost-effective than all the other possible alternatives. The ISO determined that this project is needed to mitigate reliability concerns.

2.5.6.5 Key Conclusions

The ISO study of the Fresno area yielded the following conclusions:

- One overload would occur under normal conditions for summer peak.
- Five overloads would be caused by critical single contingencies under summer peak conditions.
- Numerous overloads caused by critical multiple contingencies would occur under summer peak and off-peak conditions.

The ISO proposed solutions to address the identified overloads and received seven project proposals from PG&E through the 2011 Request Window. For projects where the expected in-service date is beyond the identified performance requirements, the ISO will continue to work with PG&E to develop operational action plans in the interim. Following is a summary of the status of PG&E's proposed solutions.

- Four request window projects were determined to be needed; these are Borden 230 kV voltage support, Oakhurst and Coarsegold UVLS project, Reedley 70 kV reinforcement and Helm-Kerman 70 kV reconductor.
- Panoche-Oroloma 115 kV line addition project was determined not to be needed in this planning cycle.
- Some of the overloads will be resolved by PG&E planned customer reliability projects. Kearney 230/70 kV transformer replacement was one such project.

Gates-Panoche #1 and #2 230 kV reconductor project and Northern Fresno 115 kV reinforcement project require further evaluation and will not be approved in this year's planning cycle.

2.5.7 Kern Area

2.5.7.1 Area Description

The Kern area is located south of the Yosemite-Fresno area and north of SCE's service territory. Midway substation, one of the largest substations in the PG&E system is located in the Kern Division and has connections to PG&E's Diablo Canyon, Gates and Los Banos substations as well as SCE's Vincent Substation. The figure below depicts the geographical location of the Kern area.

The bulk of the power that interconnects at Midway substation transfers onto the 500 kV system. A substantial amount also reaches neighboring transmission systems through Midway's 230 and 115 kV interconnections to the local areas. These interconnections include 115 kV lines to Yosemite-Fresno (north) as well as 115 and 230 kV lines to Los Padres (west). Electric customers in the Kern area are served primarily through the

230/115 kV transformers at Midway and Kern power plant substations and through local generation power plants connected to the lower voltage transmission network.

Load forecasts indicate that the Kern area should reach its summer peak demand of 2,047 MW by 2021. Load is increasing at a rate of about 23 MW per year. Accordingly, system assessments in this area include the technical studies for the scenarios under these load assumptions for summer peak conditions.

2.5.7.2 Area-Specific Assumptions and System Conditions

The Kern area study was performed in a manner consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured website lists the contingencies that were studied as part of this assessment. In addition, specific assumptions and methodology that applied to the Kern area study are provided in this section.

Generation

Generation resources in the Kern area consist of market, qualifying facilities and self-generating units. Table 2.5.7-1 lists all generating plants in the Kern area and their modeled MW capacities.

Table 2.5.7-1: Generators in the Kern Area

Plant Name	Max Capacity (MW)
Badger Creek (PSE)	49
Chalk Cliff	48
Cymric Cogen (Chevron)	21
Cadet (Chev USA)	12
Dexzel	33
Discovery	44
Double C (PSE)	45
Elk Hills	623
Frito Lay	8
Hi Sierra Cogen	49
Kern	177
Kern Canyon Power House	11
Kernfront	49
Kern Ridge (South Belridge)	76
La Paloma Generation	926
Midsun	25
Mt. Poso	56
Navy 35R	65
Oildale Cogen	40
Bear Mountain Cogen (PSE)	69
Live Oak (PSE)	48
McKittrick (PSE)	45
Rio Bravo Hydro	11
Shell S.E. Kern River	27
Solar Tannenhill	18
Sunset	225
North Midway (Texaco)	24
Sunrise (Texaco)	338
Sunset (Texaco)	239
Midset (Texaco)	42
Lost Hills (Texaco)	9
Ultra Power (OGLE)	45
University Cogen	36
Total	**3,532**
Kern Area Pumping Plants	
Wheeler Ridge Pumping Plant	53
Wind Gap Pumping Plant	130
Buena Vista Pumping Plant	58
Total	**241**

Load Forecast

Loads within the Kern area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.5.7-2 shows loads modeled for neighboring local areas in the PG&E system in the Kern area assessment as well.

Table 2.5.7-2: Load forecasts modeled in the Central Valley area assessment

Summer Peak (MW)						
PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
KERN	1,776	1,799	1,816	1,839	1,853	1,998

2.5.7.3 Study Results and Discussion

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one facility was identified with thermal overloads starting in 2021. Twenty-seven facilities were identified with high voltage concerns under the category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)

For the summer peak cases, 10 facilities were identified with thermal overloads and 24 facilities were identified with low voltage concerns under the category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

Twenty five facilities were identified with thermal overloads, and 46 facilities were identified with voltage concerns under the category C performance requirement.

Appendix A documents the worst thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

2.5.7.4 Recommended Solutions

Based on this year's reliability assessment for the Kern local area, the ISO recommended solutions to address system performance results that did not meet the thermal and low voltage performance requirements under Categories A (normal), B and C contingency conditions. Also included in this section is a discussion of the solutions and plans for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Reinforcing or upgrading the system to avoid area-wide voltage collapse;
- Installing new and additional transformer banks;
- Building new transmission lines;
- Converting low voltage lines to higher ones;
- Re-rating facilities, reconductoring, network looping and reconfiguring stations; and
- Installing shunt capacitor banks for voltage support.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns is described below. It provides information about the expected in-service dates of the mitigation projects and plans.

2.5.7.4.1 Thermal Overload Mitigations

Kern 230 kV System

The Midway-Kern 230 kV line #1 and the Kern PP bank #4 were identified as overloaded up to 125 percent and 151 percent respectively under category C5 (DCTL) and C3 (N-1-1) conditions in the 2012-2021 summer peak cases. Voltage collapse in the Kern area was also observed starting in 2012 for the category C conditions. Accordingly PG&E proposed the *Kern PP 230 kV Reinforcement* project. The ISO has identified that components of that project, consisting of the following upgrades, to address the reliability concerns in the area are needed:

- Convert Kern PP 230 kV Double Bus Single Breaker arrangement to Breaker and a half scheme.
- Replace limiting equipment on Kern PP 230/115 kV transformer #4 as necessary to achieve full bank rating.
- Approve Kern T-1-1 SPS & Midway-Kern PP 230 kV SPS.

The ISO will work with PG&E to ensure that the operating action plans are in place in the interim.

Kern 115 kV System

Several category A, B and C overloads were identified in the Kern 115 kV area. These issues were also seen in last year's reliability analysis, but they do not become a problem until 2020. PG&E had submitted a conceptual project to address these problems. This year's analysis evaluated the need for these projects starting in 2012. Accordingly, PG&E has proposed the *Kern 115 kV Area Reinforcement* project. The ISO determined that this project is needed to meet reliability concerns. This project is expected to be on-line in 2016. The ISO will work with PG&E to ensure that the operating action plans are in place in the interim.

Midway-Semitropic 115 kV line

The Midway-Semitropic 115 kV line was identified as overloaded up to 130 percent under a couple of category B and C conditions. The category B (G-1/L-1) overloads were identified in 2012. Accordingly, PG&E has proposed the Semitropic-Midway 115 kV Reconductor project. The scope of the project is to reconductor the 14.2 miles of the Semitropic-Midway line with 1,113 AAC conductor and replace terminal equipment as necessary to achieve the full conductor rating of the line. The ISO determined that this project is needed to mitigate reliability concerns. The project is expected to be on line in 2016. The ISO will work with PG&E to ensure that operating action plans are in place to address the concerns in the interim.

Taft Transformer Bank #2

The Taft 115/70 kV transformer bank #2 was identified as overloaded under a couple of category B conditions starting in 2016. Accordingly, PG&E has proposed the *Taft 115/70 kV Transformer # 2 Replacement* project. The ISO determined that this project is needed to mitigate reliability concerns. The project is expected to be online in 2016. The ISO will work with PG&E to ensure that operating action plans are in place to address the concerns in the interim.

2.5.7.4.2 Voltage Concern Mitigation

Wheeler Ridge Voltage Support

This year's analysis identified a couple of voltage concerns under category A, B and C conditions in the Wheeler Ridge area. These issues were also seen in last year's analysis, but since there was sufficient lead time to identify upgrades, the issue was deferred for future analysis. This year's analysis also identified low voltage and voltage deviation issues on the Copus 70 kV bus under various category A, B and C conditions. Accordingly, PG&E proposed the Wheeler Ridge Voltage Support project. The scope of the project is to install three 75 MVars of mechanically switched capacitors on the Wheeler Ridge 230 kV bus. This would entail expanding the 230 kV bus to a 5 breaker ring in order to accommodate these cap banks. The reconductor of 0.5 miles of Wheeler Ridge-Lakeview 70 kV line and the transfer of Copus bus to this newly reconductored line will eliminate the voltage concerns on the Copus 70 kV bus. The ISO determined that this project is needed to mitigate reliability concerns. The project is expected to be on line by 2015. The ISO will work with PG&E to ensure that operating procedures are in place to address the concerns in the interim.

2.5.7.5 Key Conclusions

The ISO study of the Northern Kern area yielded the following conclusions:

- One overload and numerous high voltage concerns would occur under normal conditions.
- Ten overloads and numerous low voltage concerns would occur under single contingency conditions.
- Numerous overloads and low voltage concerns caused by multiple contingencies would occur under summer peak conditions.

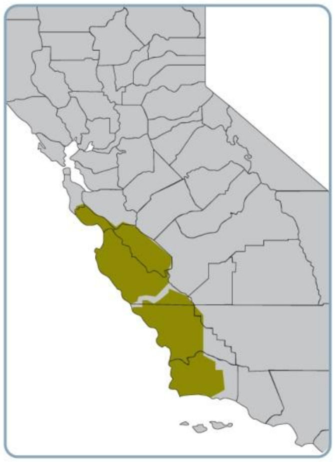
The following two projects were determined to be needed to address the performance requirements identified:

- *Kern PP 230 kV Area Reinforcement*
- *Kern PP 115 kV Area Reinforcement*

Additionally, two load interconnection projects — *Oxy Kern Front Load* and *Texaco BV Hills Load Interconnection* — (which had minimal impact on the existing transmission system) were also approved in this transmission cycle. The ISO will work with PG&E to ensure that operational action plans are in place for the remaining thermal and voltage concerns.

2.5.8 Central Coast and Los Padres Areas

2.5.8.1 Area Description



The PG&E Central Coast Division is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. The green shaded portion in the figure below depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast electric transmission system is composed of 60 kV, 115 kV 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast division are supplied via a local transmission system out of the Moss Landing Power Plant Substation. Some of the key substations are Moss Landing, Green Valley, Paul Sweet, Salinas, Watsonville, Monterey, Soledad and Hollister. The local transmission systems are: a) Santa Cruz-Watsonville, Monterey-Carmel and Salinas- Soledad-Hollister sub-areas, which are supplied via 115 kV double circuit tower lines (DCTL); b) King City, an area supplied by 230 kV lines from the Moss Landing and Panoche substations; and, c) Burns-Point Moretti sub-area which is supplied by a 60 kV line from the Monta Vista substation in Cupertino. Apart from the 60 kV transmission interconnection between the Salinas and Watsonville substations, the only interconnection among the sub-areas is at the Moss Landing substation. The Central Coast transmission system is tied to the San Jose and De Anza systems in the north, and the Greater Fresno system in the east. The total installed generation capacity is 2,881 MW including the 2,600 MW Moss Landing Power Plant.

The PG&E Los Padres Division is located in the southwestern portion of PG&E's service territory (south of the Central Coast Division). Divide, Santa Maria, Mesa, San Luis Obispo, Paso Robles and Atascadero are among the cities PG&E provides electric service to within this division. The City of Lompoc, a member of the NCPA, is also located here. Counties in the area include San Luis Obispo and Santa Barbara. The 2,400 MW Diablo Canyon Nuclear Power Plant is also located in Los Padres. Most of the power generated from the Diablo Canyon power plant is exported to the north and east through bulk 230 kV and 500 kV transmission lines, hence it has very little impact on the Los Padres area operation. There are several transmission ties to the Fresno and Kern systems, with the majority of these interconnections at the Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits. The total installed generation capacity is 1,443 MW including the 1,014 MW Moro Bay Power Plant.

Load forecasts indicate that the Central Coast and Los Padres areas should reach their summer peak demand of 834 MW and 601 MW, respectively, by 2016. By 2021, the summer peak loading for Central Coast and Los Padres would be 887 MW and 641 MW, respectively. Winter peak demand in the Central Coast are also expected to experience moderate growth, with peak load forecast at approximately 707 MW in 2016 and 748 MW in 2021. Since this area is along the coast, it has a dominant winter peak profile in certain pockets (e.g., the Monterey-Carmel sub-area). Winter peak demands could be as high as 10 percent more than summer peak demands. Accordingly, system assessments in these areas included technical studies using load assumptions for summer and winter peak conditions. The load forecast data for the Central Coast Los Padres areas is given in Table 2.5.8-2.

2.5.8.2 Area-Specific Assumptions and System Conditions

The study of the Central Coast and Los Padres areas was performed consistent with the general study methodology and assumptions that are described in section 2.3. The ISO-secured website lists the contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study of the Central Coast and Los Padres areas are provided below.

Generation

Generation resources in the Central Coast and Los Padres areas consist of market, qualifying facilities and self-generating units. All the generating facilities in the Central Coast and Los Padres areas are listed in Table 2.5.8-1. These were modeled for the 2012 through 2016 and 2021 Central Coast and Los Padres Divisions summer and Central Coast winter peak reliability assessment.

Table 2.5.8-1: Generation in the Central Coast and Los Padres Areas

No.	Generation Facility	Type	Max. Capacity (MW)	Division
1	Moss Landing Power Plant	Large Gas-Fired Units	2,600	Central Coast
2	Basic Energy Cogen (King City)	Co-Gen	120	Central Coast
3	King City Peaker	Simple-Cycle Gas Turbine	61	Central Coast
4	Sargent Canyon Cogen (Oilfields)	Co-Gen	50	Central Coast
5	Salinas River Cogen (Oilfields)	Co-Gen	50	Central Coast
6	Diablo Canyon Power Plant	Nuclear	2,400	Los Padres
7	Morro Bay Power Plant	Thermal	1,014	Los Padres
8	Union Oil (Tosco)	Thermal	6	Los Padres
9	Santa Maria	Co-Gen	8	Los Padres
10	Vandenberg Air Force Base		15	Los Padres
	Total Generation		**6,324**	**CC & LP**

Load Forecast

Loads within the Central Coast and Los Padres areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.5.8-2 shows loads modeled for the Central Coast and Los Padres areas assessment.

Table 2.5.8-2: Load forecasts modeled in the Central Coast and Los Padres area assessment

	1-in-10 Year Heat Wave Non-simultaneous Load Forecast (MW)						
	PG&E Area Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
Summer Peak (MW)	Central Coast	787	806	809	826	834	887
	Los Padres	581	587	591	597	601	641
	Total Summer Forecast	**1,368**	**1,393**	**1,400**	**1,423**	**1,435**	**1,528**
Winter Peak (MW)	Central Coast	671	686	688	701	707	748
	Los Padres	496	501	504	509	514	543
	Total Winter Forecast	**1,167**	**1,187**	**1,192**	**1,210**	**1,221**	**1,291**

2.5.8.3 Study Results and Discussion

Below is a summary of the study results of facilities in the Central Coast and Los Padres areas that were identified as not meeting thermal loading and low voltage performance requirements under normal and various system contingency conditions.

TPL 001: System Performance under Normal Conditions

For both the summer and winter peak conditions studied, no facilities were identified as not meeting either the thermal or voltage performance requirements under category A contingency conditions in the Central Coast and Los Padres Divisions.

TPL 002: System Performance Following Loss of a Single Bulk Electric System (BES) Element and ISO category B (G-1/L-1)

Three facilities (two in Central Coast and one in Los Padres) were identified as not meeting the thermal loading performance requirements under category B contingency and summer peak conditions.

Six substations in the Central Coast area were identified as not meeting the required low voltage performance requirements under category B contingency and summer peak conditions.

Nineteen substations (8 in the Central Coast and 11 in Los Padres) were identified as not meeting voltage deviation performance requirements under category B contingency and summer peak conditions.

For the Central Coast winter peak analysis, the results duplicate the Central Coast summer peak results under category B performance requirements for thermal loading, low voltage and voltage deviation conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements

Forty-seven facilities were identified as not meeting the thermal loading performance requirements under category C contingency and summer peak conditions. Ten of these facilities were in the Los Padres area.

Forty-two substations were identified as not meeting the low voltage performance requirements under category C contingency and summer peak conditions. Twenty of these facilities were in the Los Padres area.

Forty substations were identified as not meeting the voltage deviation performance requirements under category C contingency and summer peak conditions. One of these facilities was in the Los Padres area.

For the Central Coast winter peak analysis, the results mirror the Central Coast summer peak results under category C performance requirements for thermal loading, low voltage and voltage deviation conditions.

Appendix A documents the worst thermal loading, low voltage and voltage deviation profiles of facilities that were identified as not meeting the performance requirements for the summer and winter peak conditions along with the corresponding solutions.

2.5.8.4 Recommended Solutions

Based on this year's reliability assessment results for the Central Coast and Los Padres areas, the ISO identified needed solutions to address system performance results that did not meet the thermal and voltage performance requirements under NERC categories A, B and C contingency conditions. Following is a discussion of the solutions and plans for achieving the required system performance under the various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system.

The mitigation plans for addressing the identified concerns for the Central Coast and Los Padres areas include the following:

- Rerate or develop action plans to address the observed category B thermal overload and voltage concerns to cover the interim prior to implementation of the corresponding approved projects.
- Install higher rating conductor for the already approved *Watsonville 115 kV Voltage Conversion Project* to address the related category C thermal overload concerns.
- Develop operating procedures or action plans for the category C thermal overload and voltage concerns.

The Watsonville 115 kV Voltage Conversion, Crazy Horse Substation, Natividad Substation and Moss Landing 230/115 kV Transformer Replacement projects mitigate a number of thermal overloads and voltage concerns under category B and C contingencies. The Watsonville 115 kV Voltage Conversion Project converts the existing Green Valley 60 kV system to a 115 kV system, effectively adding a new 115 kV interconnection to the Santa Cruz area from Crazy Horse.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. This includes information about the expected in-service dates of the mitigation projects and plans.

2.5.8.4.1 Thermal Overload Mitigations

Green Valley-Moss Landing 115 kV Lines (# 1 or #2)

These two facilities are expected to experience a 1.4 percent thermal overload (101.38 percent loading level) only in 2013 under category B contingency and summer peak conditions in the Central Coast area. The ISO recommends rerating the existing conductors or developing an action plan to address the identified concerns. An already existing Crazy Horse Substation Project will permanently address these concerns after 2013 by providing another source to the area. The applicable contingency is the loss of one of the Green Valley-Moss Landing 115 kV lines.

Atascadero-San Luis Obispo #1 70 kV Line

This facility is projected to experience a 3.6 percent thermal overload (103.6 percent loading level) beginning in summer 2021. For this category B thermal overload, the ISO recommends line rerate, upgrading the limiting equipment or monitoring the line loading as 2021 approaches.

In the Central Coast and Los Padres areas, the study identified 47 thermal overload concerns under category C conditions – respectively, 37 and 10 in the Central Coast and Los Padres areas. Out of the 37 thermal overload concerns identified in the Central Coast area, 22 were addressed by the Watsonville 115 kV Voltage Conversion, Crazy Horse Substation, Natividad Substation and Moss Landing 230/115 kV Transformer Replacement projects. The remaining concerns were addressed by recommended use of operating procedures, action plans and load drop.

For the remaining 10 thermal overload concerns identified in the Los Padres area, the ISO recommends developing action plans, load drop, rerate and upgrading the limiting equipment to address the facilities identified as not meeting the performance requirement.

2.5.8.4.2 Voltage Concern Mitigation

The study results showed that the Central Coast 60 kV system experienced general voltage conditions that were below 0.90 p.u. primarily in 2012 and 2013 under both Categories B and C contingency conditions, particularly in substations along the Green Valley-Watsonville and Watsonville-Hollister lines. The Central Coast 115 kV system was found to experience low voltage concerns under category C conditions in 2021 particularly at the Green Valley, Camp Evers, Paul Sweet and Rob Roy 115 kV substations

Los Padres 70 kV and 115 kV System

The San Luis Obispo 70 kV system is fed by the Templeton-Atascadero 70 kV line and the San Luis Obispo #3 115/70 kV transformer bank. These two supply sources combined together serve over 17,600 customers in northern San Luis Obispo County.

The study results showed that the Los Padres 70 kV and 115 kV systems experience no category B low voltage concerns. However, for the category C conditions, 20 substations were identified as not meeting the low voltage performance requirement, primarily in 2012 and 2013. After 2013 the already approved *Cayucos 70k kV Shunt Capacitor Project* addresses the potential low voltage concerns in the area. The ISO will work with PG&E to ensure that the operating procedures are in place in the interim.

Mesa 230 kV System Reliability Concern

In 2010 the ISO identified a reliability concern, wide-area voltage collapse, in the PG&E Mesa 230 kV system and approved an interim project, *The Los Padres Transmission Project*, to address that concern. *The Los Padres Transmission Project* installed SPS at both the Mesa and Santa Maria substation in May 2011 at a cost of $1.4 million. The project drops approximately 267 MW of load because of low voltage conditions at Mesa following loss of either the Mesa 230/115 kV #2 or #3 transformer banks (category C3 condition) or the Morro Bay-Mesa #1 230 kV and the Mesa-Diablo #1 230 kV double circuit tower lines (category C5 condition). In order to achieve a long-term solution, PG&E submitted the *Morro Bay-Mesa 230 kV Line Project* in the 2011-2012 Request Window to replace the interim *Los Padres Transmission Project* solution. The Los Padres Transmission Project currently addresses the Category C conditions. The ISO has not determined the need for the Morro Bay-Mesa 230 kV Line

Project in this plan. The ISO will continue to assess the area needs in future planning assessments.

2.5.8.5 Key Conclusions

The 2011 summer and winter peak reliability assessment for the PG&E Central Coast and the summer reliability assessment for the Los Padres area revealed previously identified reliability concerns. These concerns are addressed through previously approved or identified projects. The concerns consist of thermal overloads, low voltages and voltage deviations under category B and C contingency conditions. Unlike the previous years, no area-wide voltage collapse or category A concerns were identified.

Since no facility needs were identified based on the study, no new capital projects were recommended for these two areas. The already approved and existing projects, including the *Watsonville 115 kV Voltage Conversion*, *Crazy Horse Substation*, *Natividad Substation* and *Moss Landing 230/115 kV Transformer Replacement* projects mitigate a number of thermal overloads and voltage concerns under the identified category B and C contingencies. For example, the *Watsonville 115 kV Voltage Conversion Project* adds a new 115 kV interconnection source to the Santa Cruz area from Crazy Horse.

Based on this year's study, the Central Coast and Los Padres areas show an improved and relatively robust system with most of the concerns observed in the study resulting from implementation year gaps of already approved interim and long-term projects and identified solutions.

2.6 SCE Area (Bulk Transmission)

2.6.1 Area Description

Southern California Edison (SCE) serves over 13 million people in a 50,000 square mile area of central, coastal and southern California, excluding the city of Los Angeles and certain other cities. In 2011, the SCE system load peaked at 23,388 MW on September 7, 2011. The bulk transmission system consists of 500 kV and 230 kV transmission facilities. Most of the SCE load is located within the Los Angeles Basin. However, the fastest load growth occurs in the eastern part of the SCE service territory in the Inland Empire area. The SCE service area is shown in map on the left. The CEC's load growth forecast for the entire SCE area is about 350 MW per year. The CEC's 1-in-10 heat wave load forecast includes the SCE service area, the Pasadena Water and Power Department and the California Department of Water Resources pump load. The 2016 and 2021 summer peak forecast loads are 26,987 MW and 28,878 MW, respectively. Most of the SCE area load is served by local generation that includes nuclear, qualifying facilities, hydro and oil/gas-fired power plants. The remaining demand is served by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and Desert Southwest.

In general, the SCE transmission system includes 500 kV and 230 kV facilities, with small pockets of 115 kV and 66 kV network transmissions. The bulk system includes seven areas: Metro, North of Magunden, South of Magunden, Antelope-Bailey, North of Lugo, East of Lugo and Eastern. The Metro area consists of the major load centers in Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara counties. The boundary of the Metro area is marked by Vincent, Lugo and Devers 500 kV substations. The North of Magunden, South of Magunden and Antelope-Bailey areas are composed of 500 kV, 230 kV and 66 kV transmission systems north of Vincent. North of Lugo consists of 230 kV, 115 kV and 55 kV transmission system stretching from Lugo to Kramer and Inyokern and into Nevada. East of Lugo consists of 500 kV, 230 kV and 115 kV transmission systems from Lugo to Eldorado. The eastern area includes 500 kV, 230 kV and 115 kV transmission systems from Devers to Palo Verde in Arizona and 230 kV transmission systems from Devers to Julian Hinds.

2.6.2 Area-Specific Assumptions and System Conditions

The SCE area study was performed consistent with the general study methodology and assumptions described in section 2.3.

The contingencies that were performed as part of this assessment are listed on the ISO-secure website. In addition, specific assumptions and methodology that applied to the SCE area study are provided below.

Generation

Table 2.6-1 lists the major generation plants in the SCE area.

Table 2.6-1: List of the major generation plants in the SCE area.

Generation Plants	Max. Capacity
Alamitos	2010
Big Creek Hydro	1020
Blythe	493
Cool Water	628
El Segundo	670
Etiwanda (Mt. Vista)	640
High Desert	830
Huntington Beach	904
IEEC	810
Long Beach	260
Mandalay	560
Mountain View	1050
Ormond Beach	1516
Pastoria	750
Redondo Beach	1355
San Onofre Nuclear Generating Station (SONGS)	2250 MW (SCE's Share = 1720 MW)

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.6-2 provides a summary of the SCE substation load in the summer peak assessment.

The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.6-2: Summer peak load forecasts modeled in the SCE area assessment

SCE Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)						
SUBSTATION	2012	2013	2014	2015	2016	2021
Alamitos 220/66 (S)	194	195	196	196	199	212
Alberhill 500/115 (S)	0	0	391	399	406	448
Antelope 220/66 (S)	682	715	656	669	688	772
Barre 'AB' 220/66 (S)	729	750	757	757	763	805
Big Creek 1 220/33 (S)	9	10	10	10	10	10
Blythe (Walc) 161/33 (S)	64	66	67	67	68	72
Center 'A' 220/66 (S)	513	529	532	533	536	561
Chino 'A' 220/66 (S)	728	760	781	873	886	956
Del Amo 'A' 220/66 (S)	535	567	567	568	572	591
Devers 220/115 (S)	998	1031	1037	1044	1060	1114
Eagle Mountain 220/66 (S)	2	2	2	2	2	2
Eagle Rock 220/66 (S)	203	217	222	228	236	271
El Casco 220/115 (S)	201	213	220	231	240	269
El Nido 220/66 (S)	437	462	469	470	471	500
Eldorado 220/115 (S)	18	18	18	18	18	18
Ellis 'A' 220/66 (S)	750	785	786	794	803	864
Etiwanda 'E' 220/66 (S)	680	718	758	767	784	859
Goleta 220/66 (S)	325	336	336	335	337	350
Gould 220/66 (S)	125	132	132	133	134	143
Hinson 'A' 220/66 (S)	548	540	548	547	550	569
Victor SCE 220/115 (S)	546	570	577	584	595	644
Johanna 220/66 (S)	477	509	583	587	594	644
Kramer 220/115 (S)	198	206	208	210	213	207
La Cienega 220/66 (S)	528	542	544	546	552	581
La Fresa 'A' 220/66 (S)	741	770	774	783	791	832
Laguna Bell 'AB' 220/66 (S)	641	657	656	655	658	683
Lighthipe 'AB' 220/66 (S)	494	512	514	516	521	555
Mesa 220/66 (S)	657	679	685	688	692	728
Mira Loma 220/66 (S)	755	791	806	696	713	789
Moorpark 'A' 220/66 (S)	768	799	805	810	818	882
Olinda 220/66 (S)	417	436	442	445	451	486
Padua 220/66 (S)	701	725	718	717	725	762
Rector 220/66 (S)	784	817	823	820	834	903
Rio Hondo 220/66 (S)	750	775	775	778	788	833
San Bernardino 220/66 (S)	614	642	645	645	653	693
Santa Clara 220/66 (S)	516	546	558	567	579	640
Santiago 'A' 220/66 (S)	826	871	880	892	911	726
Saugus 'A' 220/66 (S)	738	917	930	940	950	1039

SCE Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)						
SUBSTATION	2012	2013	2014	2015	2016	2021
Springville 220/66 (S)	221	226	226	234	232	243
Valley 'AB' 500/115 (S)	678	713	728	745	765	856
Valley 'C' 500/115 (S)	963	1016	676	694	720	830
Vestal 220/66 (S)	160	166	166	166	168	177
Viejo 220/66 (S)	372	388	389	391	394	694
Villa Park 220/66 (S)	766	797	746	750	758	807
Vista 'A' 220/66 (S)	779	812	815	616	625	675
Vista 220/115 (S)	277	289	291	294	298	318
Walnut 220/66 (S)	685	709	710	710	712	750
Windhub 220/66 (S)	0	0	95	97	100	110
Wilderness 220/66 (S)	0	0	0	380	381	393
Camino 220/66 (S)	2	2	2	2	2	2
Chevmain 220/66 (S)	166	167	167	167	168	169
Cima 220/66 (S)	3	3	3	3	3	3
Etiwanda 'Ameron' (S)	18	18	18	18	18	18
Goodrich 220/33 (S)	289	289	288	288	288	286
Lewis 220/66 (S)	544	547	553	554	555	559
Total	**24,812**	**25,953**	**26,281**	**26,630**	**26,987**	**28,878**

2.6.3 Study Results and Discussion

Power flow study results of facilities in the SCE area under normal and various category B, C and D contingency conditions are discussed in the following sections. Transient stability studies of the bulk 500 kV and 230 kV systems were also performed and are discussed in the following sections.

2.6.4 Recommended Solutions

Recommended solutions that address each of the identified facilities that did not meet the thermal and voltage performance requirements under category A, B and C conditions are discussed in the following sections for each area within the SCE service territory.

2.7 SCE Local Areas Assessment

In addition to the SCE's bulk area study, studies were performed for its seven local areas. These are discussed below.

2.7.1 North of Magunden

2.7.1.1 Area Description

The North of Magunden area consists of the transmission system north of the Magunden substation. This area includes load at Rector, Vestal and Springville as well as generation at Big Creek.

One major transmission project in this area has been approved by the ISO in prior cycles. This project, *the San Joaquin Cross Valley Loop Transmission Project*, is expected to be in service in 2014.

2.7.1.2 Area-Specific Assumptions and System Conditions

The North of Magunden area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology that applied to the North of Magunden area study are provided below.

Generation

Table 2.7.1-1 lists the major generation facilities in the North of Magunden area.

Table 2.7.1-1: List of the major generation plants in the North of Magunden area

Generation Plants	Max. Capacity (MW)
Big Creek Hydro	1020

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7.1-2 provides a summary of the SCE substation load in the summer peak assessment. The substations located in the North of Magunden area are highlighted in the table.

The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.7.1-2: Summer peak load forecasts modeled in the SCE's North of Magunden area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
Substation	2012	2013	2014	2015	2016	2021
Big Creek 220/33 kV	9	10	10	10	10	10
Rector 220/66 kV	784	817	823	820	834	903
Springville 220/66 kV	221	226	226	234	232	243
Vestal 220/66 kV	160	166	166	166	168	177

2.7.1.3 Study Results and Discussion

Following is a summary of the study results of facilities in the North of Magunden area under normal and various system contingency conditions.

TPL 001: System Performance under Normal Conditions

All facilities met the performance requirements under category A normal conditions from 2012-2021.

TPL 002: System Performance Following Loss of a Single BES Element and ISO category B (G-1/L-1)

All facilities met the performance requirements under category B contingency conditions from 2012-2021.

TPL 003: System Performance Following Loss of Two or More BES Elements

All facilities met the performance requirements under category C contingency conditions from 2012 to 2021 when Big Creek/San Joaquin RAS is considered.

2.7.1.4 Recommended Solutions

Based on this year's reliability assessment results of the North of Magunden area, the ISO recommended solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories A, B and C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secured power transfer and adequate load serving capability of the transmission system.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. This includes information about the expected in-service dates of the mitigation projects and plans.

2.7.1.4.1 Thermal Overload Mitigations

The 2012-2021 reliability assessment results did not indicate any thermal overload issues in the North of Magunden Area that require mitigation.

2.7.1.4.2 Voltage Concern Mitigation

The 2012-2021 reliability assessment results did not indicate any voltage concerns in the North of Magunden Area that require mitigation.

2.7.1.4.3 Transient Voltage Dip Concern Mitigations

The 2012-2021 reliability assessment results did not indicate any transient voltage dip concerns in the North of Magunden Area that require mitigation.

2.7.1.5 Key Conclusions

The 2012-2021 summer peak and spring off-peak reliability assessment of the SCE North of Magunden area did not indicate any system performance concerns.

2.7.2 South of Magunden

2.7.2.1 Area Description

The South of Magunden area consists of the SCE transmission system between Magunden and Vincent. The South of Magunden area consists of:

- 230 kV transmission system between Magunden and Vincent; and
- WECC Path 26: Three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation.

The ISO has approved one major transmission project in this area in prior cycles — *Tehachapi Renewable Transmission Project* (entire project will be completed and in-service in 2015).

2.7.2.2 Area-Specific Assumptions and System Conditions

The South of Magunden area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology that applied to the South of Magunden area study are provided below.

Generation

Table 2.7.2-1 lists the major existing generation plants in the South of Magunden area. Several generation projects are currently under development in the area. As described in Section 2.3.2.5, two scenarios were considered in the study: one without new renewable generation and the other with new renewable generation in the area.

Table 2.7.2-1: List of the major existing generation plants in the South of Magunden area

Generation Plants	Max. Capacity (MW)
Omar/Sycamore	600
Pastoria	750
Antelope Area Wind and Hydro	389
Vincent Area Wind	272
CDWR Generation (Warne)	76

Load Forecast

The ISO summer peak base cases assume the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7.2-2 provides a summary of the SCE substation load in the Big Creek corridor in the summer peak assessment.

The ISO spring off-peak base cases assume 60 percent of the summer peak load in the Rector, Springville and Vestal substations and 50 percent of the summer peak load in the Antelope and Bailey substations.

Table 2.7.2-2: Summer peak load forecasts modeled in the SCE's South of Magunden area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
Substation	2012	2013	2014	2015	2016	2021
Antelope-Bailey	682	715	746	766	788	882
Rector	784	817	823	820	834	903
Springville	221	226	226	234	232	243
Vestal	160	166	166	166	168	177

2.7.2.3 Study Results and Discussion

Following is a summary of the study results of facilities in the South of Magunden area under normal and various system contingency conditions.

Without new renewable generation

TPL 001: System Performance under Normal Conditions

For the summer peak cases, four 500 kV buses (i.e., Antelope 500 kV bus, Windhub 500 kV bus, Whirlwind 500 kV bus and Vincent 500 kV bus) were identified with voltages greater than 525 kV (i.e., 1.05 p.u.) under normal conditions. SCE proposed an exception for these buses to the voltage standard in the ISO Planning Standards and proposed using a high voltage limit of 550 kV under normal conditions. The ISO concurred with this exception.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

All facilities met the performance requirements under category B conditions from 2012 to 2021.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, one contingency (i.e., loss of Vincent #3 and #4 500/230 kV transformer banks) was identified as causing one facility overload (Vincent #1 500/230 kV transformer bank), under the category C thermal loading performance requirement.

The Appendix A documents the worst thermal loading and voltage concerns that did not meet system performance requirements. Proposed solutions are listed next to identified criteria performance concerns.

With new renewable generation

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one 500 kV bus (i.e., Windhub 500 kV bus) was identified with voltage greater than 525 kV (i.e., 1.05 p.u.) under normal conditions. SCE proposed an exemption for this bus to the voltage standard in the ISO Planning Standards and proposed using a high voltage limit of 550 kV under normal conditions. The ISO accepted this exemption.

TPL 002: System Performance Following Loss of a Single BES Element and ISO category B (G-1/L-1)

For the summer peak cases, two contingencies were identified as causing two facility overloads under the category B thermal loading performance requirement.

For the summer peak cases, one contingency (Lebec-Pastoria 230 kV line) resulted in voltage deviation greater than 5 percent, under the category B contingency voltage performance requirement.

For the spring off-peak cases, one contingency (Antelope-Magunden #2 230 kV line outage with the largest combined cycle module at Pastoria Energy Facility already out of service) caused one facility overload (Antelope-Magunden #1 230 kV line) under the category B thermal loading performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, four contingencies caused five facility overloads under the category C thermal loading performance requirement.

For the spring off-peak cases, one contingency (loss of Vincent #3 and #4 500/230 kV transformer banks) caused one facility overload (Vincent #1 500/230 kV transformer bank) under the category C thermal loading performance requirement.

Appendix A documents the worst thermal loading and voltage concerns that do not meet system performance requirements. Proposed solutions are listed next to identified criteria performance concerns.

The transient stability analysis of the South of Magunden area did not reveal any performance concerns.

2.7.2.4 Recommended Solutions

Based on the 2012-2021 reliability assessment results of the South of Magunden area, the ISO recommended solutions that address the issues found at each of the identified facilities that did not meet the thermal and voltage performance requirements under category A, B and C contingencies. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under normal and contingency conditions. The recommended solutions were designed to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- installing new reactive support; and
- developing operating procedures

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. This includes information about the expected in-service dates of the mitigation projects and plans.

2.7.2.4.1 Thermal Overload Mitigations

Without new renewable generation

Vincent #1 500/230 kV Transformer Bank
The Vincent #1 500/230 kV transformer bank is overloaded under one category C outage (Vincent #3 500/230 kV transformer bank and Vincent #4 500/230 kV transformer bank). The ISO Operation Procedure #7550 is recommended to mitigate the Vincent #1 500/230 kV transformer bank overload under the T-1-1 outage of the Vincent #3 and #4 500/230 kV transformer banks. The Vincent #2 500/230 kV transformer bank can be switched in after the first outage to address any potential reliability concern.

With new renewable generation

Vincent #1 500/230 kV Transformer Bank
The Vincent #1 500/230 kV transformer bank is overloaded under one category C outage (Vincent #3 500/230 kV transformer bank and Vincent #4 500/230 kV transformer bank). The ISO Operation Procedure #7550 is recommended to mitigate the Vincent #1 500/230 kV transformer bank overload under the T-1-1 outage of the Vincent #3 and #4 500/230 kV transformer banks. The Vincent #2 500/230 kV transformer bank can be switched in after the first outage to address any potential reliability concern.

Antelope #1 500/230 kV Transformer Bank
The Antelope #1 500/230 kV transformer bank is overloaded under one category B outage (Antelope #2 500/230 kV transformer bank outage with the largest combined cycle module at Pastoria Energy Facility already out of service) and one category C outage (Antelope #2 500/230 kV transformer bank and Lebec-Pastoria 230 kV line). The transformer bank loading exceeds the 24-hour rating, but is within the 1-hour rating. The ISO recommends developing an operating procedure with an in-service date on or before June 1, 2014 to reduce generation in the Tehachapi area or in the north of Path 26 area, post contingency, to address this potential loading concern.

Antelope #2 500/230 kV Transformer Bank

The Antelope #2 500/230 kV transformer bank is overloaded under one category B outage (Antelope #1 500/230 kV transformer bank outage with the largest combined cycle module at Pastoria Energy Facility already out of service) and one category C outage (Antelope #1 500/230 kV transformer bank and Lebec-Pastoria 230 kV line). The transformer bank loading exceeds the 24-hour rating, but is within the 1-hour rating. The ISO recommends developing an operating procedure with an in-service date on or before June 1, 2014 to reduce generation in the Tehachapi area or in the north of Path 26 area, post contingency, to address this potential loading concern

Pardee-Vincent 230 kV line and Santa Clara-Vincent 230 kV line

Both of these lines are overloaded under one category C outage (Antelope #1 500/230 kV transformer bank and Antelope #2 500/230 kV transformer bank). The ISO recommends developing an operating procedure with an in-service date on or before June 1, 2021 to reduce generation in the Tehachapi area or in the north of Path 26 area after the first contingency to address this potential loading concern.

Antelope-Magunden #1 230 kV line

This line is overloaded under one category B outage (Antelope-Magunden #2 230 kV line outage with the largest combined cycle module at Pastoria Energy Facility already out of service). The ISO recommends developing an operating procedure with an in-service date on or before January 1, 2016 to increase the generation north of Pastoria when the Edmonston pumping load is high and Pastoria generation is low, to address any potential loading concern.

2.7.2.4.2 Voltage Concern Mitigation

With new renewable generation

Edmonston 14.4 kV and 230 kV Buses and Pastoria 230 kV Buses

Voltage deviation greater than 5 percent at Edmonston 14.4 kV and 230 kV buses and Pastoria 230 kV buses starting in 2021 was identified under one category B outage (Lebec-Pastoria 230 kV line). The ISO is considering installing reactive support at the Pastoria 230 kV Substation as a conceptual mitigation. Because the voltage deviation seen in 2021 is less than 6 percent, the ISO recommends further evaluation in a future planning cycle.

2.7.2.4.3 Short Circuit Duty Mitigation

Request Window Project Submittal – Antelope Breaker Upgrades Project

The Antelope Breaker Upgrades Project is proposed by SCE to replace seven circuit breakers and upgrade three circuit breakers at Antelope 230 kV bus to mitigate short circuit duty concerns. This project is determined to be needed by the ISO.

2.7.2.5 Key Conclusions

The 2012 to 2021 summer peak and spring off-peak reliability assessment of the SCE South of Magunden area revealed several reliability concerns. These concerns consist of thermal overloads and voltage deviations under category B and C contingency conditions. Based on the assessment results, the ISO proposes operating procedures and potential reactive support to address the identified reliability concerns to meet the

ISO standards for the area. One reliability project submission was received through the 2011 Request Window.

The following project is determined to be needed by the ISO:

- *Antelope Breaker Upgrades*: Proposed in-service date is June, 2013.

2.7.3 Antelope-Bailey

2.7.3.1 Area Description

The Antelope-Bailey area is composed of the SCE transmission system North of Vincent and consists of the Antelope-Bailey 66 kV system.

One major transmission project, the East Kern Wind Resource Area (EKWRA) 66 kV Reconfiguration Project (in-service date: December 2013), modeled in the new renewable case has been approved in prior planning cycles.

Once the transmission project is in-service (with new renewable case), the area will consist of the Antelope/Bailey/Windhub 66 kV system.

2.7.3.2 Area-Specific Assumptions and System Conditions

The Antelope-Bailey area study was performed consistent with the general study methodology and assumptions described in section 2.3. As described in Section 2.3.2.5, two cases were studied for the area: 1) with new renewable in which all the new renewables and the EKWRA project were modeled; 2) without new renewables in which the new renewables and the EKWRA project were not modeled.

The ISO-secured website lists the contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the Antelope-Bailey area study are provided below.

Generation

Table 2.7.3-1 lists the existing maximum generation capacity in the Antelope-Bailey area.

Table 2.7.3-1: Maximum generation capacity in the Antelope-Bailey area

Generation Plants	Max. Capacity (MW)
Antelope Area	411

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses. Table 2.7.3-2 shows the Antelope-Bailey area load in the summer peak assessment "with new renewables" and "without new renewables" cases. The load in the "without new renewables" cases was higher because it is based on the local area 1-in-10 peak load which does not coincide with the overall SCE area 1-in-10 peak load. The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.7.3-2: Summer peak load forecasts modeled in the SCE's Antelope-Bailey area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)							
Substation	Case	2012	2013	2014	2015	2016	2021
Antelope-Bailey 220/66 kV	Without new renewables	682	715	746	766	787	N/A
Antelope-Bailey 220/66 kV	With new renewables	N/A	N/A	675	N/A	708	801

2.7.3.3 Study Results and Discussion

Following is a summary of the study results in the Antelope-Bailey area that were identified as not meeting thermal loading, voltage performance, and stability performance requirements under various system contingency conditions.

Power Flow Study Results

With new renewables

A summary of the study results of facilities in the Antelope-Bailey area with new renewables under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one facility (Westpac leg of Westpac-Bailey-Neenach 66 kV line) was identified with thermal overloading concerns under the category A thermal loading performance requirements. After further investigation, the updated line rating was modeled in the cases and no thermal overloading concerns for category A were identified.

For the summer peak cases, no facilities had voltage performance concerns under the category A contingency voltage performance requirements.

For the spring off-peak cases, no facilities had thermal overloads or voltage performance concerns under the category A thermal loading and voltage performance requirements.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

For the summer peak cases, two contingencies causing one facility (Westpac leg of Westpac-Bailey-Neenach 66 kV line) to have thermal overload were identified under the category B thermal loading performance requirements. After further investigation, the updated line rating was modeled in the cases and no thermal overloading concerns for category B were identified.

For the summer peak cases, no facilities were identified with voltage performance concerns under the category B contingency voltage performance requirements.

For the spring off-peak cases, no facilities were identified with thermal overloads or voltage performance concerns under the category B thermal loading and voltage performance requirements.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, three contingencies resulted in three facilities having thermal overloads under the category C thermal loading performance requirements.

For the summer peak cases, four contingencies resulted in eight facilities having low voltage concerns under the category C voltage performance requirements.

For the summer peak cases, one contingency resulted in one facility having voltage deviations greater than 10 percent under the category C voltage performance requirements.

For the spring off-peak cases, no facilities had thermal overloads or voltage performance concerns under the category C thermal loading and voltage performance requirements.

Without new renewables

Following is a summary of the study results of facilities in the Antelope-Bailey area without new renewables under normal and various system contingency conditions.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, no facilities had thermal loading or voltage performance concerns under the category A thermal loading and voltage performance requirements.

For the spring off-peak cases, one facility was identified with thermal overloading concerns under the category A thermal loading performance requirements.

For the spring off-peak cases, no facilities had voltage performance concerns under the category A contingency voltage performance requirements.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

For the summer peak cases, no facilities were identified as having thermal overloads under the category B thermal loading performance requirements.

For the summer peak cases, one contingency resulted in three facilities having low voltage concerns under the category B voltage performance requirements.

For the summer peak cases, three contingencies resulted in six facilities having voltage deviation greater than 10 percent under the category B voltage performance requirements.

For the spring off-peak cases, one contingency caused four facilities to have thermal overload under the category B thermal loading performance requirements.

For the spring off-peak cases, six contingencies resulted in 54 facilities having 36 high and 18 low voltage concerns under the category B voltage performance requirements.

For the spring off-peak cases, one contingency resulted in 24 facilities having voltage deviation greater than 10 percent under the category B voltage performance requirements.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, one contingency resulted in a diverged power flow solution. In addition, 15 contingencies caused 19 facilities to have thermal overload concerns under the category C thermal loading performance requirements.

For the summer peak cases, three contingencies caused 16 facilities to have high voltage concerns under the category C voltage performance requirements.

For the summer peak cases, one contingency resulted in one facility having voltage deviation greater than 10 percent under the category C voltage performance requirements.

For the spring off-peak cases, 12 contingencies caused 19 facilities to have thermal overload concerns under the required category C thermal loading performance requirements.

For the spring off-peak cases, six contingencies resulted in 43 facilities having 18 high and 25 low voltage concerns under the category C voltage performance requirements.

For the spring off-peak cases, four contingencies resulted in 25 facilities having voltage deviation greater than 10 percent under the category C voltage performance requirements.

Appendix A documents the worst thermal loadings, high/low voltages and voltage deviations concerns of facilities that do not meet reliability requirements. Proposed solutions are listed next to identified criteria performance concerns.

2.7.3.4 Recommended Solutions

Based on this year's reliability assessment results for the Antelope-Bailey area, the ISO recommended solutions to address system performance results for each of the facilities that did not meet the thermal loading or voltage performance requirements under category A, B and C contingency conditions. Also included in this section is a discussion of the solutions, expected in-service dates, and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- installing new SPS or develop operating procedures;
- installing shunt capacitors; and
- completion of approved EKWRA project.

2.7.3.4.1 Thermal Overload Mitigations

With new renewables

Helijet-Anaverde-Antelope 66 kV Line

The Helijet leg of Helijet-Anaverde-Antelope 66 kV line is overloaded under three category C outages. The ISO recommends modifying existing SPS to trip Palmdale 66 kV load to mitigate the thermal overloads for the following outages:

- Lancaster-Littlerock-Piute 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1;
- Lancaster-Littlerock-Piute 66 kV #1 and Acton-Palmdale-Shuttle 66 kV #1; and
- Oasis-Quartzhill-Palmdale 66 kV #1 and Acton-Ritter 66 kV #1.

Since the thermal overloads were identified in 2021, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Without new renewable

The case was studied without the EKWRA project modeled in the event its in-service date is delayed. Several thermal overloads were identified without the EKWRA project. Most of the overloads should be mitigated with EKWRA in service, and a comprehensive list of these overloads can be found in Appendix A. The EKWRA project is expected to be in-service in December 2013. In the interim, the ISO recommends using an operational action plan to mitigate the thermal overloads.

Diverged Power Flow Case

One category C contingency resulted in a diverged power flow solution. The ISO recommends modifying existing SPS in 2014 to trip Lancaster load for the outage of Antelope-Calcement 66 kV #1 and Calcement-Monolith-Rosamond-Windfarm 66 kV #1.

For a short-term solution, switching shunt capacitor banks is sufficient to meet the requirement. The ISO will continue to monitor the contingency in the next planning cycle and will determine the expected in-service date for the mitigation plan. The long-term solution is EKWRA.

Antelope-Rosamond 66 kV Line

The Antelope-Rosamond 66 kV line is overloaded under one category C outage. The ISO recommends installing a new SPS to trip Calcement 66 kV load to mitigate the thermal overload for the outage of Antelope-Calcement 66 kV #1 and Antelope-Delsur-Rosamond 66 kV #1. The SPS is expected to be in-service in summer 2012. The long-term solution is EKWRA.

Antelope-Lanpri-Shuttle-Lancaster 66 kV Line

The Antelope leg of Antelope-Lanpri-Shuttle-Lancaster 66 kV line is overloaded under five category C outages. The ISO recommends installing a new SPS to trip Shuttle 66 kV load to mitigate the thermal overloads for the following three outages:

- Antelope-Del Sur 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.
    - Since the thermal overload was identified in 2013, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.
- Antelope-Del Sur 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1.
    - Since the thermal overload was identified in 2016, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.
- Antelope-Lancaster-Oasis-Tap 68 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.
    - The SPS is expected to be in-service in summer 2012. The long-term solution is EKWRA.

For the following two outages, the ISO recommends modifying existing SPS to trip Lancaster load:

- Antelope-Lancaster-Oasis 66 kV #1 and Del Sur-Riteaid-Lancaster 66 kV #1
- Antelope-Del Sur 66 kV #1 and Antelope-Lancaster-Oasis 66 kV #1

The modification to the SPS to trip Lancaster load is expected to be in-service in summer 2012. The long-term solution is EKWRA.

The Lancaster leg of Antelope-Lanpri-Shuttle-Lancaster 66 kV line is overloaded under six category C outages. The ISO recommends modifying existing SPS to trip Lancaster 66 kV load to mitigate the thermal overloads for the following outages:

- Antelope-Del Sur 66 kV #1 and Antelope-Calcement 66 kV #1;
    - Since the thermal overload was identified in 2014, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.
- Antelope-Lancaster-Oasis 66 kV #1 and Littlerock-Palmdale-Rockair-Helijet 66 kV #1;
    - Since the thermal overload was identified in 2016, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.
- Antelope-Del Sur 66 kV #1 and Antelope-Lancaster-Oasis 66 kV #1;
- Antelope-Del Sur 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1;
- Antelope-Lancaster-Oasis 66 kV #1 and Del Sur-Riteaid-Lancaster 66 kV #1; and
- Del Sur-Riteaid-Lancaster-Tap 50 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1.

The modification to the SPS is expected to be in-service in summer 2012. The long-term solution is EKWRA.

The section from Lanpri Tap to Shuttle Tap of Antelope-Lanpri-Shuttle-Lancaster 66 kV line is overloaded under two category C outages. The ISO recommends modifying existing SPS to trip Lancaster 66 kV load to mitigate the thermal overloads for the following outages:

- Antelope-Shuttle-Quartzhill 66 kV #1 and Del Sur-Riteaid-Lancaster 66 kV #1; and.
- Antelope-Shuttle-Quartzhill 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1.

Because the thermal overloads were identified in 2015, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Del Sur-Riteaid-Lancaster 66 kV Line

The Del Sur leg of Del Sur-Riteaid-Lancaster 66 kV line is overloaded under three category C outages. The ISO recommends modifying existing SPS to trip Lancaster 66 kV load to mitigate the thermal overloads for the following outages:

- Antelope-Lanpri-Lancaster-Shuttle 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1;
    - Since the thermal overload was identified in 2016, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.

- Antelope-Lanpri-Lancster-Shuttle 66 kV #1 and Line Oasis-Quartzhill-Palmdale 66 kV #1;
  - Since the thermal overload was identified in 2013, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.
- Antelope-Lancaster-Oasis 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.
  - The SPS is expected to be in-service in summer 2012. The long-term solution is EKWRA.

Helijet-Anaverde-Antelope 66 kV Lines

The Helijet leg of Helijet-Anaverde-Antelope 66 kV line is overloaded under one category C outage. The ISO recommends modifying existing SPS to switch shunt capacitor banks to mitigate the thermal overloads for the outage of Oasis-Quartzhill-Palmdale 66 kV #1 and Acton-Ritter 66 kV #1.

Since the thermal overloads were identified in 2016, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Rosamond-Del Sur-Antelope 66 kV Lines

The Rosamond leg of Rosamond-Del Sur-Antelope 66 kV line is overloaded under one category C outage. The ISO recommends installing a new SPS to switch shunt capacitor bank to mitigate the thermal overloads for the outage of Antelope-Calcement 66 kV #1 and Antelope-Rosamond 66 kV #1.

Since the thermal overloads were identified in 2013, the ISO will continue to monitor the line flow in the next planning cycle and will determine the expected in-service date for the mitigation plan.

2.7.3.4.2 Voltage Concern Mitigation

With new renewables

Helijet and Rock Air 66 kV Substations

Low voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to trip Helijet 66 kV load to mitigate the voltage performance concerns for the outage of Antelope-Anaverde-Helijet 66 kV #1 and Oasis-Quartzhill-Palmdale 66 kV #1.

Since the low voltage concerns were identified in 2021, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Little Rock, Shuttle, and Wilsona 66 kV Substations

Low voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to trip Shuttle 66 kV load to mitigate the voltage performance concerns for the outage of Antelope-Lanpri-Lancster-Shuttle 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.

Since the low voltage concerns were identified in 2021, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Little Rock and Wilsona 66 kV Substations

Low voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to trip Little Rock 66 kV load to mitigate the voltage performance concerns for the outage of Antelope-Anaverde-Helijet 66 kV #1 and Lancaster-Littlerock-Piute 66 kV #1. As the low voltage concerns were identified in 2021, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Rock Air 66 kV Substation

Low voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to trip Helijet 66 kV load to mitigate the voltage performance concerns for the outage of Antelope-Anaverde-Helijet 66 kV #1 and Acton-Palmdale-Shuttle 66 kV #1.

Since the low voltage concerns were identified in 2021, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Shuttle 66 kV Substation

Voltage deviation greater than 10 percent was identified under one category C outage. The ISO recommends installing a new SPS to trip Shuttle 66 kV load to mitigate the voltage performance concerns for the outage of Antelope-Lanpri-Lancster-Shuttle 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.

Since the voltage deviation concerns were identified in 2021, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Without new renewables

The case was studied without EKWRA project modeled in the event its in-service date is delayed. Several high/low voltages and voltage deviations were identified without EKWRA project. Most of the high/low voltages and voltage deviations should be mitigated with EKWRA in service and the comprehensive list of these high/low voltages and voltage deviations can be found in Appendix A. EKWRA project is expected to be in-service in December 2013. In the interim, the ISO recommends the use of an operational action plan to mitigate the voltage concerns.

Gorman, Frazier Park, and Kern River Substations

Low voltages and voltage deviations were identified under one category B outage. The ISO recommends installing shunt capacitors at Frazier Park to mitigate the voltage performance concerns for the outage of Bailey-Gorman 66 kV #1 and Kern River Generating Unit #1. The shunt capacitors are expected to be in-service in summer 2012.

Monolith 66kV Substation

High voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to switch shunt capacitor banks to mitigate the voltage performance concerns for the outage of Cummings-Monolith 66 kV #1 and Monolith-Calcement-Windparks 66 kV #1.

Since the high voltage concerns were identified in 2014, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Goldtown 66kV Substation

High voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to switch shunt capacitor banks to mitigate the voltage performance concerns for the outage of Monolith-Calcement-Goldtown-Windland 66 kV #1 and Lancaster-Goldtown 66 kV #1.

Since the high voltage concerns were identified in 2014, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan.

Arbwind, Breeze, Monolith, Dutchwind, Encanwind, Flowind, Havilah, Loraine, Northwind, Oakwind, Southwind, Varwind, Walkerbn, and Zondwind Substations

High voltage concerns were identified under one category C outage. The ISO recommends installing a new SPS to switch shunt capacitor banks to mitigate the voltage performance concerns for the outage of Cummings-Monolith 66 kV #1 and Monolith-Calcement-Goldtown-Windland 66 kV #1.

Since the high voltage concerns were identified in 2013, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation plan. The long-term solution is EKWRA.

Del Sur 66 kV Substation

A voltage deviation concern was identified under one category B outage. The ISO recommends installing a new SPS to switch shunt capacitor banks to mitigate the voltage performance concerns for the outage of Antelope-Del Sur 66 kV #1.

Since the voltage deviation concerns were identified in 2016, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the mitigation. The long-term solution is EKWRA.

Shuttle 66 kV Substation

A voltage deviation greater than 10 percent was identified under one category C outage. The ISO recommends installing a new SPS to trip Shuttle load to mitigate the voltage performance concerns for the outage of both Antelope-Lanpri-Lancaster-Shuttle 66 kV #1 and Antelope-Shuttle-Quartzhill 66 kV #1.

Since the voltage deviation concerns were identified in 2013, the ISO will continue to monitor the voltage in the next planning cycle and will determine the expected in-service date for the SPS. The long-term solution is EKWRA.

2.7.3.4.3 Transient Voltage Dip Concern Mitigations

Loss of the Antelope 230/66 kV and Bailey 230/66 kV bank were assessed and no transient and post-transient concerns were identified.

2.7.3.5 Key Conclusions

The 2012 to 2021 summer peak and spring off-peak reliability assessment of the SCE Antelope-Bailey area revealed several system performance concerns. These concerns consist of thermal overloads, high/low voltages, and voltage deviations under category B and C contingency conditions. Based on the assessment results, the ISO proposed to install shunt capacitors and special protection systems or operating procedures to address the identified reliability concerns to meet the ISO standards for the area. SCE proposed installing FrazierPark/Gorman12kV shunt capacitors and updating Antelope-Bailey operating procedures. Upon review by the ISO, the proposed mitigation solutions have met the ISO reliability standards for 2012.

For 2013-2021 system performance concerns, the ISO will continue to monitor the line flow and voltages in the next planning cycle and will update the expected in-service date for the recommended mitigation plans.

2.7.4 North of Lugo Area

2.7.4.1 Area Description

The North of Lugo transmission system serves San Bernardino, Kern, Inyo and Mono counties. The figure below depicts the geographic location of the North of Lugo area. The area extends more than 270 miles.

The North of Lugo electric transmission system is composed of 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has inter-ties with LADWP and Sierra Pacific Power. In the south, it connects to the Eldorado substation through the Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah substation through the Lugo-Pisgah #1 and #2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The North of Lugo area can be divided into the following sub-areas: North of Control; South of Control to Inyokern; South of Inyokern to Kramer; South of Kramer; and Victor.

2.7.4.2 Area-Specific Assumptions and System Conditions

The North of Lugo area study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured website lists the contingencies that were studied as part of this assessment.

As described in section 2.3.2.5, two cases were studied for the area: 1) with new renewables in which all the new renewables and the EKWRA project were modeled; 2) without new renewables in which the new renewables and the EKWRA project were not modeled.

Additionally, specific methodology and assumptions that were applicable to the North of Lugo area study are provided below.

Generation

Generation resources in the North of Lugo area consist of market and qualifying facilities. A list of all generating facilities in the North of Lugo area is given in Table 2.7.4-1.

Table 2.7.4-1: Generation in the North of Lugo Area

No.	Generation Facility	Maximum Capacity (MW)
1	Bishop Hydro Units 2 & 6	13
2	Bishop Hydro Units 3 & 4	16
3	Poole & Lundy	14
4	Rush Creek	12
5	BLM East & West (Units 7, 8 & 9)	72
6	Borax	45
7	Calgen (Units 1, 2 & 3)	80
8	Kerrgen*	17
9	Kerr McGee*	55
10	Luz (Units 8 & 9) – SEGS 8 & 9	160
11	McGen	104
12	Mogen	51
13	Navy 2 (Units 4, 5 & 6)	90
14	Casa Diablo	30
15	Oxbow	50
16	SEGS 1	20
17	SEGS 2	29
18	Sungen (Units 3, 4, 5, 6 & 7)	140
19	Alta Unit 1	65
20	Alta Unit 2	81
21	Alta Unit 3 (combustion turbines)	132
22	Alta Unit 3 (steam turbine)	108
23	Alta Unit 4 (combustion turbines)	132
24	Alta Unit 4 (steam turbine)	108
25	HDPP (Units 1, 2 & 3)	525
26	HDPP (steam turbine)	325
Total		2474

*Note that the maximum net generation export as seen at Searless 115 kV (McGen+Kerrgen-Load) is limited to no more than 26 MW.

Load Forecast

The ISO base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses. Table 2.7.4-2 shows loads modeled for the North of Lugo area assessment. The load in the "without new renewables" cases was higher because it is based on the local area 1-in-10 peak load which does not coincide with the overall SCE area 1-in-10 peak load.

Table 2.7.4-2: Load forecasts modeled in the North of Lugo area

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)							
Substation	**Case**	**2012**	**2013**	**2014**	**2015**	**2016**	**2021**
Kramer 220/115	With new renewables	N/A	N/A	290	N/A	273	254
Kramer 220/115	Without new renewables	441	451	463	483	482	534
Victor-Kramer-Inyo 220/115	With new renewables	N/A	N/A	609	N/A	621	669
Victor-Kramer-Inyo 220/115	Without new renewables	813	834	858	883	907	1,072

2.7.4.3 Study Results and Discussion

Following is a summary of the study results in the North of Lugo area that were identified as not meeting thermal loading, voltage performances, and stability performance requirements under various system contingency conditions.

Power Flow Study Results

With new renewables

TPL 001: System Performance under Normal Conditions

For the summer peak cases, no facilities had thermal overloads under the category A thermal loading performance requirements.

For the summer peak cases, two facilities (Control 55 kV and Inyo 230 kV) were identified with high voltage concerns under the category A voltage performance requirements. SCE proposed an exception for these buses to the voltage standard in the ISO Planning Standards and requested to use a high voltage limit of1.1 p.u. under normal conditions. The ISO concurred with the exception.

For the spring off-peak cases, no facilities were identified with thermal overloads under the category A thermal loading performance requirements.

For the spring off-peak cases, five facilities (Control 55 kV, Control 115 kV, Inyo 115 kV, Inyo PS 115 kV, and Inyo 230 kV) were identified with high voltage concerns under the category A voltage performance requirements. SCE proposed an exception for these buses to the voltage standard in the ISO Planning Standards and requested to use a high voltage limit of 1.1 p.u. under normal conditions. The ISO concurred with the exception.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (G-1/L-1)

For the summer peak cases, no facilities were identified with thermal overloads or voltage performance concerns under the category B thermal loading performance requirement.

For the spring off-peak cases, no facilities were identified with thermal overloads or voltage performance concerns under the category B thermal loading performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, one contingency case resulted in a diverged power flow solution under the category C contingency thermal loading requirements.

For the summer peak cases, four contingencies resulted in eight high voltage concerns at Control 55 kV, Control 115 kV, Inyo 115 kV, Inyo PS 115 kV, Oxbow A 230 kV and Oxbow B 230 kV under the category C voltage performance requirements. SCE submitted updated reactive capabilities for the BS Hydro 2 and 6 and BS Hydro 3 and 4 units. After further analysis, no voltage performance concerns under the category C voltage were identified.

For the spring off-peak cases, one contingency case resulted in a diverged power flow solution under the category C contingency thermal loading requirements.

For the spring off-peak cases, four contingencies resulted in twelve high voltage concerns at Control 55 kV, Control 115 kV, Casa Diablo 115 kV, Sherwin 115 kV, Inyo 115 kV, Inyo PS 115 kV, Oxbow A 230 kV and Oxbow B 230 kV under the category C voltage performance requirements. SCE submitted updated reactive capabilities for the BS Hydro units 2, 3, 4 and 6. After further analysis, no voltage performance concerns under the category C voltage were identified.

- The transient simulation shows that the system is stable following the Kramer-Lugo 230 kV N-2 contingency.
- The transient simulation shows that the system is unstable following the Victor-Lugo 230 kV N-2 contingency.

TPL 004: System Performance under Extreme Events

Loss of the entire Lugo 500/230 kV substation was assessed for category D performance. The North of Lugo system is unstable following this event. To restore system synchronism, extensive generation tripping in the North of Lugo area and load tripping in the LA Basin are required. Loss of the Lugo Substation will trigger the Kramer, High Desert power plant and South of Lugo SPS. But manual load tripping in the south of Lugo is still needed to mitigate thermal overloads.

Without new renewables

TPL 001: System Performance under Normal Conditions

For the summer peak cases, no facilities were identified with thermal overloads under the category A thermal loading performance requirement.

For the summer peak cases, one facility (Inyo 230 kV) was identified with high voltage concerns under the category A voltage performance requirements. SCE proposed an exception for these buses to the voltage standard in the ISO Planning Standards and to use a high voltage limit of 1.1 p.u. under normal conditions. The ISO concurred with the exception.

For the spring off-peak cases, no facilities had thermal overloads under the category A thermal loading performance requirement.

For the spring off-peak cases, one facility (Inyo 230 kV) was identified with high voltage concerns under the category A voltage performance requirements. SCE proposed an exception for these buses to the voltage standard in the ISO Planning Standards and to use a high voltage limit of 1.1 p.u. under normal conditions. The ISO concurred with the exception.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (G-1/L-1)

For the summer peak cases, no facilities were identified with thermal overloads under the category B thermal loading performance requirement.

For the summer peak cases, one contingency resulted in one facility having voltage deviation greater than 10 percent under the category B voltage performance requirements.

For the spring off-peak cases, no facilities had thermal overloads or voltage performance concerns under the category B thermal loading performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, one contingency case resulted in a diverged power flow solution under the category C contingency thermal loading requirements.

For the summer peak cases, five contingencies resulted in seven high and one low voltage concerns at Control 55 kV, Control 115 kV, Inyo 115 kV, Inyo PS 115 kV, Oxbow A 230 kV and Tortilla 115 kV under the category C voltage performance requirements. SCE submitted updated reactive capabilities for the BS Hydro 2 & 6 and BS Hydro 3 & 4 units. After further analysis, only Tortilla 115 kV voltage performance concerns under the category C voltage were identified.

For the summer peak cases, one contingency resulted in one facility having voltage deviation greater than 10 percent under the category C voltage performance requirements.

For the spring off-peak cases, one contingency case resulted in a diverged power flow solution under the category C contingency thermal loading requirements.

For the spring off-peak cases, four contingencies resulted in six high voltage concerns at Control 55 kV, Control 115 kV, Inyo 115 kV, and Oxbow A 230 kV under the category C voltage performance requirements. SCE submitted updated reactive capabilities for the BS Hydro 2 & 6 and BS Hydro 3 & 4 units. After further analysis, no voltage performance concerns under the category C voltage were identified.

- The transient simulation shows that the system is stable following the Kramer-Lugo 230 kV N-2 contingency.
- The transient simulation shows that the system is unstable following the Victor-Lugo 230 kV N-2 contingency.

TPL 004: System Performance under Extreme Events

Loss of the entire Lugo 500/230 kV Substation was assessed for category D performance. The north of Lugo system would be unstable following this event. To restore system synchronism, extensive generation tripping in the North of Lugo area and load tripping in the LA Basin would be required. Loss of the Lugo Substation will trigger the operation of Kramer, High Desert power plant and South of Lugo SPS. Manual load tripping south of Lugo would still be needed to mitigate thermal overloads.

Appendix A documents the worst thermal loadings, high/low voltages and voltage deviations concerns of facilities that do not meet system performance requirements. Proposed solutions are listed next to identified criteria performance concerns.

2.7.4.4 Recommended Solutions

Based on this year's reliability assessment results for the North of Lugo area, the ISO recommended solutions to address system performance results that did not meet the thermal or voltage performance requirements or the system stability requirements under the contingency conditions. Also included in this section is a discussion of the solutions, expected in-service dates and plans for achieving the required system performance under the various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Modifying the existing Kramer SPS
- Modifying the existing High Desert Power Project RAS; and
- Installing shunt capacitors at the Tortilla substation.

2.7.4.4.1 Thermal Overload Mitigations

With new renewables

Power flow case divergence

One contingency case resulted in a diverged power flow solution. The ISO recommends modifying existing Kramer SPS to address the potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

Without new renewable

Power flow case divergence

One contingency case resulted in a diverged power flow solution. The ISO recommends modifying existing Kramer SPS to address the potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

2.7.4.4.2 Voltage Concern Mitigation

With new renewables

None noted.

Without new renewables

Tortilla 115 kV Substation

Low voltage concerns were identified under one category C outage. The ISO recommends installing shunt capacitors at the Tortilla Substation area to mitigate the voltage concerns for the outage of Kramer-Lugo 230 #1 and Colwater-Seg2-Tortilla 115 #1.

Tortilla 115 kV Substation

A voltage deviation greater than 10 percent was identified under one category B and one category C outage. The ISO recommends installing shunt capacitors at the Tortilla Substation area to mitigate the voltage concerns for the outage of the following:

- Colwater-Seg2-Tortilla 115 kV #1; and
- Kramer-Lugo 230 kV #1 and Colwater-Seg2-Tortilla 115 kV #1.

The shunt capacitors at the Tortilla substation will be in-service in summer 2013. For 2012, SCE requested an exception for this bus to the voltage standard in the ISO Planning Standards and proposed to use a high voltage limit of 1.1 p.u. under contingency condition. The ISO accepted this exception.

2.7.4.4.3 Transient Stability Mitigations

The ISO recommends that SCE evaluate modifications to the existing High Desert Power Project SPS to mitigate the transient instability problem for the loss of Victor-Lugo 230 kV N-2 category C condition.

The ISO recommends that SCE evaluate modifications to the existing Kramer SPS and High Desert Power Project RAS to mitigate the transient instability problem for the loss of Lugo 500/230 kV N-2 category D condition. After further investigation, it was noticed that once the Jasper Substation is in service; a tie between Jasper-Pisgah 230 kV might be required to improve the system reliability for the loss of both Lugo 500/230 kV transformers under category C and category D outage condition.

In the interim, it is recommended that an operating procedure with an in-service date on or before June 1, 2012 be developed to address the identified transient instability problems. The ISO will work with SCE to ensure that the operating procedure is in place on time.

2.7.4.5 Key Conclusions

The summer peak and spring off-peak reliability assessment of the North of Lugo area revealed several reliability concerns. These concerns consist of thermal overloads, high/low voltages, voltage deviations, and system instability under category B and C contingency conditions.

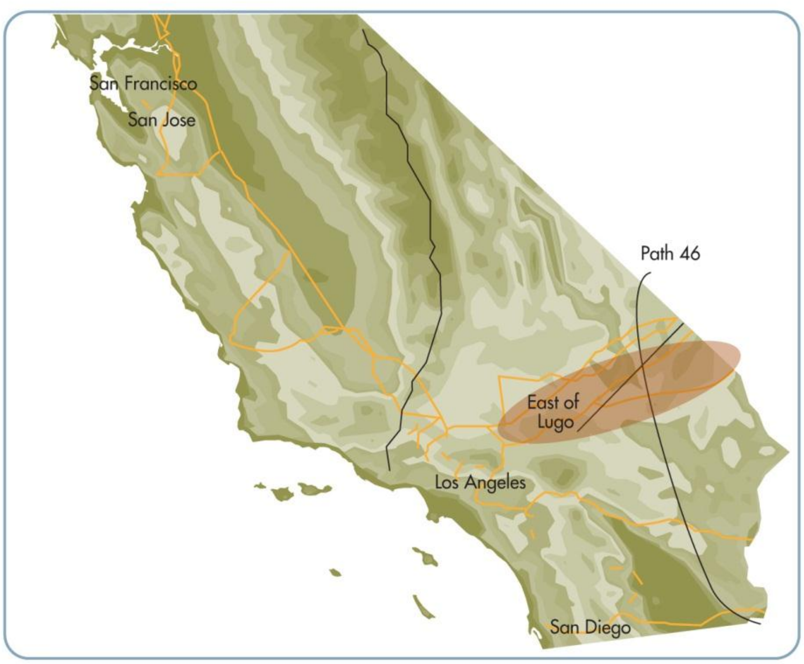
Based on the assessment results, the ISO proposes to modify existing High Desert Power Project SPS and Kramer SPS, and to install shunt capacitors to address the identified reliability concerns to meet the ISO standards for the North of Lugo area. SCE proposed to modify High Desert Power Project RAS and Kramer RAS and to install shunt capacitors at the Tortilla Substation. Upon review by the ISO, the proposal mitigated the ISO reliability concerns, and the ISO concurs with the proposal. The ISO will work with SCE to ensure that the proposed SPS modifications will be in place to meet the reliability needs in 2012.

2.7.5 East of Lugo

2.7.5.1 Area Description

The East of Lugo area consists of the transmission system between the Lugo and Eldorado substations. The East of Lugo area is a major transmission corridor connecting California with Nevada and Arizona; a part of Path 46 (West of River). The East of Lugo bulk system consists of the following:

- 500 kV transmission lines from Lugo to Eldorado and Mohave;
- 230 kV transmission lines from Lugo to Pisgah to Eldorado; and
- 115 kV transmission line from Eldorado to Cool Water.



2.7.5.2 Area-Specific Assumptions and System Conditions

The East of Lugo area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology that applied to the East of Lugo area study are provided below.

Generation

There is no major generation located in the East of Lugo area.

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7.5-1 provides a summary of the Eldorado area load in the summer peak assessment. The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.7.5-1: Summer peak load forecasts modeled in the SCE area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
Substation	2012	2013	2014	2015	2016	2021
Eldorado Area	21	21	21	21	21	21

2.7.5.3 Study Results and Discussion

A summary of the study results of facilities in the East of Lugo area under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

All facilities met the performance requirements under category A normal conditions from 2012-2021.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

All facilities met the performance requirements under category B contingency conditions from 2012-2021.

No single outage results in loss of demand of more than 250 MW.

TPL 003: System Performance Following Loss of Two or More BES Elements

For the summer peak cases, the Lugo-Victorville 500 kV tie line overloaded up to 107.1 percent of its applicable rating under a category C contingency (N-1-1) of the Palo Verde-Colorado River and Eldorado-Lugo 500 kV lines in 2012 and 2013.

For the summer peak and spring off-peak cases, a category C outage of the Eldorado -Mohave and Lugo-Mohave 500 kV lines (N-1-1) resulted in a diverged power flow case for all study years.

Appendix A documents the worst thermal loading of facilities not meeting the performance requirements for the summer peak and spring off-peak conditions along with the corresponding proposed solutions.

2.7.5.4 Recommended Solutions

Based on the 2012-2021 reliability assessment results of the East of Lugo area, the ISO recommended solutions to address identified issues for each facility that did not meet the thermal performance requirements under category C contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system.

Lugo-Victorville 500 kV Tie Line Overload

The existing ISO Operation Procedure No. 6610 (SCE's SOB T-135) is recommended to mitigate the Lugo-Victorville 500 kV tie overload under the L-1-1 outage of the Eldorado-Lugo 500 kV line and the Palo Verde-Colorado 500 kV line in 2012 and 2013. The operation procedure can be applied to reduce the power flow through the LADWP system following the first contingency by bypassing the series capacitor banks on LADWP 500 kV lines between the McCullough and Victorville 500 kV substations as needed.

Loss of Demand in the Mohave Area

The Mead-Mohave 69 kV system was not adequate to pick up all the loads in the Mohave area for the N-1-1 outage of the Eldorado-Mohave and Lugo-Mohave 500 kV lines. The existing protection system will shed load up to 50 MW in a controlled manner. No new mitigation is recommended.

2.7.5.5 Key Conclusions

The 2012-2021 summer peak and spring off-peak reliability assessment of the SCE East of Lugo area identified the Lugo-Victorville 500 kV line thermal overload. Additionally, the power flow diverged in the Mohave 69 kV area under category C contingencies. The existing ISO Operation Procedure No. 6610 and the protection system in the Mead-Mohave 69 kV system are adequate to address these issues. No new mitigation is required or recommended.

2.7.6 Eastern Area

2.7.6.1 Area Description

The Eastern area includes the SCE owned 500 kV, 230 kV and 115 kV transmission facilities from Devers to Palo Verde in Arizona.

The following are major transmission projects in this area approved by the ISO:

- Valley-Devers-Colorado River Transmission Project (in-service date: 2013);
- Devers/Mirage 115 kV Split Project (in-service date: 2012); and
- Coachella-Devers 230 kV Loop-in to Mirage (in-service date: 2013).

2.7.6.2 Area-Specific Assumptions and System Conditions

The Eastern area reliability assessment was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology that applied to the Eastern area study are provided below.

Generation

Table 2.7.6-1 lists the major generation plants in the Eastern area.

Table 2.7.6-1: List of the major generation plants in the Eastern area

Generation Facility	Max. Capacity (MW)
Blythe	493
Indigo Thermal	136

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7.6-2 provides a summary of the Eastern area substation load in the summer peak assessment. The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.7.6-2: Summer peak load forecasts modeled in the Eastern area assessment

Eastern area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)						
SUBSTATION	2012	2013	2014	2015	2016	2021
Blythe (Walc) 161/33 (S)	64	66	67	67	68	72
Camino 220/66 (S)	2	2	2	2	2	2
Devers 220/115 (S)	998	1031	1037	1044	1060	1114
Eagle Mountain 220/66 (S)	2	2	2	2	2	2

2.7.6.3 Study Results and Discussion

A summary of the reliability assessment results for the Eastern area under normal and various system contingency conditions is provided below.

TPL 001: System Performance under Normal Conditions

All facilities met the performance requirements under category A normal conditions from 2012-2021.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

One facility, the existing Ramon-Mirage 230 kV line did not meet the performance requirements under category B contingency conditions. The line was loaded to 105 percent of its emergency rating in the 2014 off peak case under a G-1/L-1 contingency involving Coachella Valley-Mirage 230 kV line and Ormond Beach Unit#1. The line is scheduled to be upgraded as part of the Path 42 transmission project with an in-service date of fourth quarter 2013. The planned upgrade will address the loading concern and no further mitigation will be required.

TPL 003: System Performance Following Loss of Two or More BES Elements

The following contingencies did not meet the performance requirements under Category C contingency conditions from 2012-2021. The L-1-1 contingency involving Julian Hinds-Mirage and Iron Mountain-Camino-Gene-Mead 230 kV lines caused an overload on the Eagle Mountain-Blythe SC 161 kV line and did not meet transient and post-transient stability requirements without reducing Blythe Energy generation after the first contingency. As well, the L-1-1 contingency involving Julian Hinds-Mirage 230 kV line and Blythe-Blythe SC 161 kV tie did not meet transient stability requirements without reducing Blythe Energy generation after the first contingency. The existing Blythe Energy RAS may not mitigate these concerns.

2.7.6.4 Recommended Solutions

Based on the 2012-2021 reliability assessment results for the Eastern area, the ISO recommended solutions that address the issues found at each of the identified facilities that did not meet the thermal and voltage performance requirements under category A, B and C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secured power transfer and adequate load serving capability of the transmission system.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. This includes information about the expected in-service dates of the mitigation projects and plans.

2.7.6.4.1 Thermal Overload Mitigations

The L-1-1 contingency involving Julian Hinds-Mirage and Iron Mountain-Camino-Mead-Gene 230 kV lines caused an overload on the Eagle Mountain-Blythe 161 kV line and did not meet transient and post-transient stability requirements without reducing Blythe Energy generation after the first contingency.

2.7.6.4.2 Voltage Concern Mitigation

The L-1-1 contingency involving Julian Hinds-Mirage and Iron Mountain-Camino-Mead-Gene 230 kV lines did not meet post-transient voltage deviation requirements as well as thermal and transient stability requirements without reducing Blythe Energy generation after the first contingency.

2.7.6.4.3 Transient Voltage Dip Concern Mitigations

The L-1-1 contingency involving Julian Hinds-Mirage and Iron Mountain-Camino-Mead-Gene 230 kV lines caused an overload on the Eagle Mountain-Blythe 161 kV line and instability in the area beginning in 2012. As well, the L-1-1 contingency involving Julian Hinds-Mirage 230 kV line and Blythe-Blythe SC 161 kV tie did not meet transient and post-transient stability requirements beginning in 2012.

The ISO received a proposal for one transmission project in the Eastern area through the 2011-2012 Request Window. The proposal involves construction of a new Julian Hinds-Mirage 230 kV line to address the above system performance concerns. The ISO recommends a more cost effective solution which is to develop an operating procedure to address these system performance concerns by limiting Blythe generation after the first outage. This operating procedure along with the existing Blythe RAS will mitigate these conditions.

2.7.6.5 Key Conclusions

The 2012-2021 summer peak and spring off-peak reliability assessment for the SCE Eastern area identified two reliability concerns. The ISO recommends the following measures to mitigate the concerns identified:

- No further mitigation is required to address the overloading of the existing Ramon-Mirage 230 kV line since the line is scheduled to be upgraded as part of the Path 42 transmission project with an in-service date of Q4 2013.
- Develop an operating procedure for limiting Blythe generation following an outage of 230 kV and 161 kV elements in the area including Julian Hinds-Mirage 230 kV line, Iron Mountain-Camino 230 kV line, and Blythe SC-Blythe 161 kV tie to prevent thermal overload and instability in the area. Development of the operating procedure has been completed as of January 2012 and CAISO Operating Procedure 7720F is now in effect.

The ISO received a proposal for one transmission project in the Eastern area through the 2011-2012 Request Window. The proposal involves construction of a new Julian Hinds-Mirage 230 kV line to address the above system performance concern. The ISO determined that this project is not needed.

2.7.7 Metro Area

2.7.7.1 Area Description

The Metro area consists of the major load centers in Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara counties. The boundary of the Metro area is marked by the Vincent, Lugo and Devers 500 kV substations.

2.7.7.2 Area-Specific Assumptions and System Conditions

The Metro area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology that applied to the Metro area study are provided below.

Generation

Table 2.7.7-1 lists the major existing generation plants in the Metro area.

Table 2.7.7-1: List of the major generation plants in the Metro area

Generation Plants	Max. Capacity (MW)
Alamitos	1,950
El Segundo	670
Long Beach	260
Mountain Vista	640
Redondo Beach	1,280
Mountain View	1,072
San Onofre Nuclear Generating Station (SONGS)	2,150 MW (SCE's Share = 1,720 MW)

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7.7-2 provides a summary of the SCE substation load in the summer peak assessment.

The ISO spring off-peak base cases assume 60 percent of the summer peak load.

Table 2.7.7-2: Summer peak load forecasts modeled in the SCE area assessment

SCE Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)						
SUBSTATION	2012	2013	2014	2015	2016	2021
Alamitos 220/66 (S)	194	195	196	196	199	212
Alberhill 500/115 (S)	0	0	391	399	406	448
Barre 'AB' 220/66 (S)	729	750	757	757	763	805
Center 'A' 220/66 (S)	513	529	532	533	536	561
Chevmain 220/66 (S)	166	167	167	167	168	169
Chino 'A' 220/66 (S)	728	760	781	873	886	956
Del Amo 'A' 220/66 (S)	535	567	567	568	572	591
Eagle Rock 220/66 (S)	203	217	222	228	236	271
El Casco 220/115 (S)	201	213	220	231	240	269
El Nido 220/66 (S)	437	462	469	470	471	500
Ellis 'A' 220/66 (S)	750	785	786	794	803	864
Etiwanda 'Ameron' (S)	18	18	18	18	18	18
Etiwanda 'E' 220/66 (S)	680	718	758	767	784	859
Goodrich 220/33 (S)	289	289	288	288	288	286
Gould 220/66 (S)	125	132	132	133	134	143
Hinson 'A' 220/66 (S)	548	540	548	547	550	569
Johanna 220/66 (S)	477	509	583	587	594	644
La Cienega 220/66 (S)	528	542	544	546	552	581
La Fresa 'A' 220/66 (S)	741	770	774	783	791	832
Laguna Bell 'AB' 220/66 (S)	641	657	656	655	658	683
Lewis 220/66 (S)	544	547	553	554	555	559
Lighthipe 'AB' 220/66 (S)	494	512	514	516	521	555
Mesa 220/66 (S)	657	679	685	688	692	728
Mira Loma 220/66 (S)	755	791	806	696	713	789
Moorpark 'A' 220/66 (S)	768	799	805	810	818	882
Olinda 220/66 (S)	417	436	442	445	451	486
Padua 220/66 (S)	701	725	718	717	725	762
Rio Hondo 220/66 (S)	750	775	775	778	788	833
San Bernardino 220/66 (S)	614	642	645	645	653	693
Santa Clara 220/66 (S)	516	546	558	567	579	640
Santiago 'A' 220/66 (S)	826	871	880	892	911	726
Saugus 'A' 220/66 (S)	738	917	930	940	950	1039
Valley 'AB' 500/115 (S)	678	713	728	745	765	856
Valley 'C' 500/115 (S)	963	1016	676	694	720	830
Viejo 220/66 (S)	372	388	389	391	394	694
Villa Park 220/66 (S)	766	797	746	750	758	807
Vista 220/115 (S)	277	289	291	294	298	318
Vista 'A' 220/66 (S)	779	812	815	616	625	675
Walnut 220/66 (S)	685	709	710	710	712	750
Wilderness 220/66 (S)	0	0	0	380	381	393

2.7.7.3 Study Results and Discussion

A summary of the reliability assessment results for the Metro area under normal and various system contingency conditions is provided below.

TPL 001: System Performance under Normal Conditions

All facilities met the thermal loading requirements under category A conditions from 2012-2021. One facility, the San Bernardino-Devers 230 kV line, is loaded to 100 percent of its rating under normal conditions in the 2016 off peak case.

In the 2016 summer peak case, voltage at one bus (Red Bluff 500 kV) exceeds 1.05 p.u or 525 kV under normal conditions. SCE proposed an exemption from the ISO high voltage standard and requested using a high voltage limit of 550 kV under normal conditions. The ISO has accepted the exemption.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

All facilities met the thermal performance requirements under category B contingency conditions from 2012- 2021.

One facility, Viejo 230 kV bus did not meet the minimum voltage limit of 0.9 p.u. starting in 2015 and the maximum voltage deviation limit of 5 percent starting in 2013 for a G-1/L-1 outage of San Onofre-Viejo 230 kV line with one San Onofre unit out of service. SCE proposed a temporary exemption for this bus from the ISO voltage deviation standard for category B conditions for the 2012-2014 period and instead requested a voltage deviation limit of 7 percent. The ISO has accepted the exemption.

TPL 003: System Performance Following Loss of Two or More BES Elements

The following facilities did not meet the performance requirements under category C contingency conditions from 2012-2021.

- Mira Loma #1 or #2 500/230 kV transformers was overloaded following a T-1/L-1 contingency involving either one of the transformers and the Chino-Mira Loma #3 230 kV line starting in 2015.
- Chino-Mira Loma #3 230 kV line was overloaded following a T-1-1 contingency involving Mira Loma #1 and #2 500/230 kV transformers starting in 2012.
- Barre-Ellis 230 kV line was overloaded following an L-2 outage of San Onofre-Santiago #1 and #2 230 kV lines starting in 2012.
- A G-2 outage involving two San Onofre units caused non-convergence in the 2016 and 2021 summer peak cases.

NUC 001: System Performance under scenarios that can affect SONGS

The technical studies were conducted in compliance with the NUC-001-2 Standard, the Nuclear Plant Interface Requirements (NPIRs) for the San Onofre Nuclear Generating Station (SONGS), and per the requirements of the ISO Tariff Section 24 and the Business Practice Manual (BPM) for the Transmission Planning Process. The planning analyses are conducted annually as part of the development of the ISO

Transmission Plan. The consolidated Southern California base cases with a 1-in-5 load forecast were used to perform the studies.

Post-transient governor power flow and transient stability studies were conducted to assess the performance related to the SONGS under normal and emergency conditions. In this planning cycle conducted during 2011-2012, the planning studies were conducted for multiple years from 2012 to 2021. For the purpose of testing system performance for NUC-001-2, the following scenarios were used:

- 2016 summer peak
- 2021 summer peak

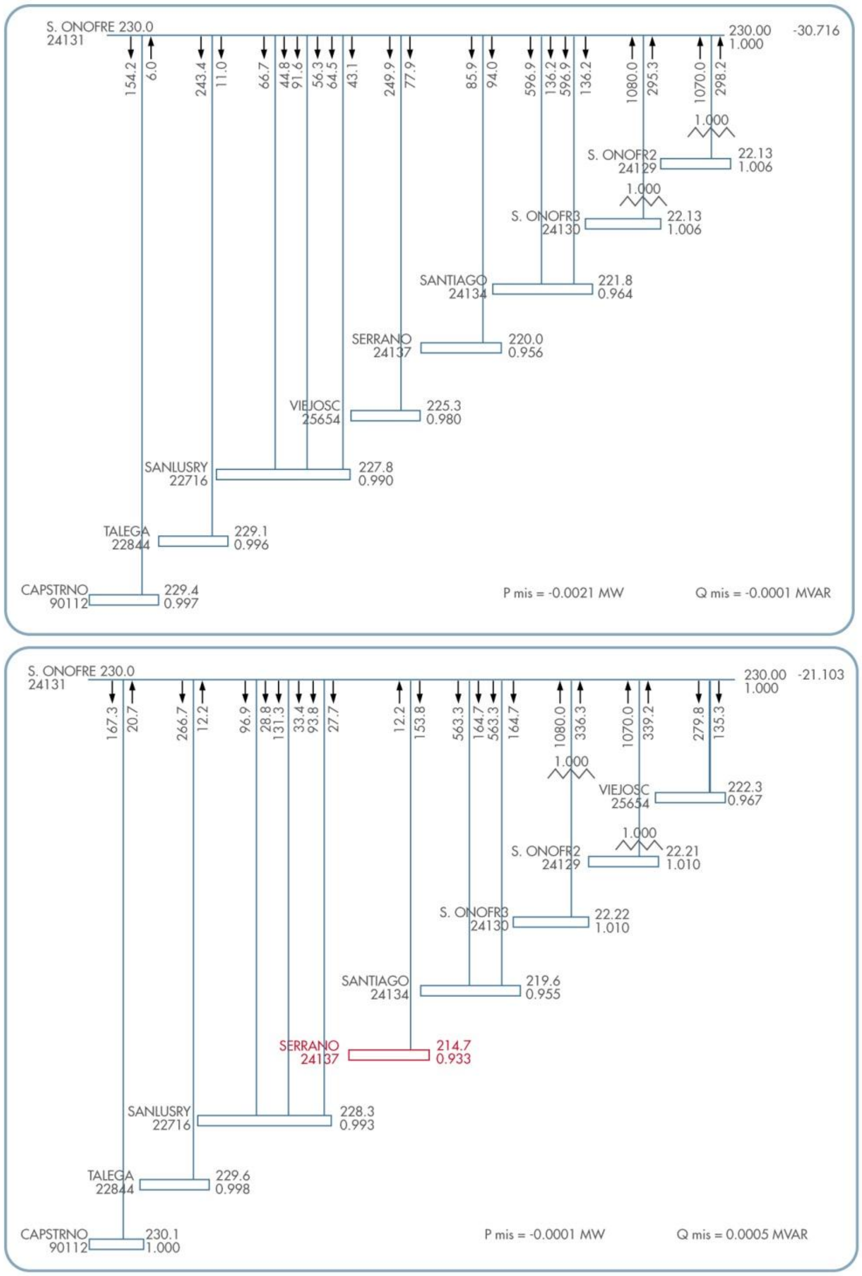
Several contingencies were run in the SCE area for thermal, voltage and stability concerns. These contingencies included:

- Loss of a single SONGS unit (G-1)
- Loss of both SONGS units (G-2)
- Loss of a single SONGS unit with the other unit already off-line (G-1-1)
- All critical contingencies of transmission lines connected to SONGS (Category B, C and D)
- Loss of major generation plants in SCE area
- Loss of critical transmission lines and interties in SCE system
- Loss of entire load at Santiago substation (largest load block in LA Basin according to the information provided in the base case).

The base cases modeled all transmission circuits connected to SONGS switchyard with the status normally in-service. The study results showed that:

- The steady state voltage at SONGS 230 kV switchyard was 230 kV under 2016 summer peak conditions and 230 kV under 2021 summer peak conditions. This is within the range specified in the NPIRs and in Appendix E of the Transmission Control Agreement for SONGS (218kV to 234kV). The following snapshot shows that for the 2016 and 2021 study cases the initial voltage at SONGS 230kV bus was 230kV.
- The SONGS generator is regulating the 230kV bus voltage to 1.00 per unit in 2016 summer peak case and in 2021 summer peak case.

Figure 2.7.7-1: SONGS 230kV Bus Voltage (2016 and 2021



The study results from various studies show that there are no thermal overloads or transient stability concerns related to the SONGS units under normal or emergency conditions. In 2016 and 2021, SONGS G-2 contingency results in post-transient divergence. This can be mitigated by increasing generation in the LA Basin. The ISO has historically addressed this concern by maintaining minimum generation dispatch requirements in Southern California in accordance with the SCIT Nomogram. No additional mitigation is considered necessary other than periodically updating and following established minimum generation requirements.

The following plots that are for two of the most severe contingencies and for a sudden loss of load demonstrate that there are no stability concerns related to the SONGS units.

Figure 2.7.7-2: Rotor Angles in SCE for SONGS (G-2) Contingency (2016)

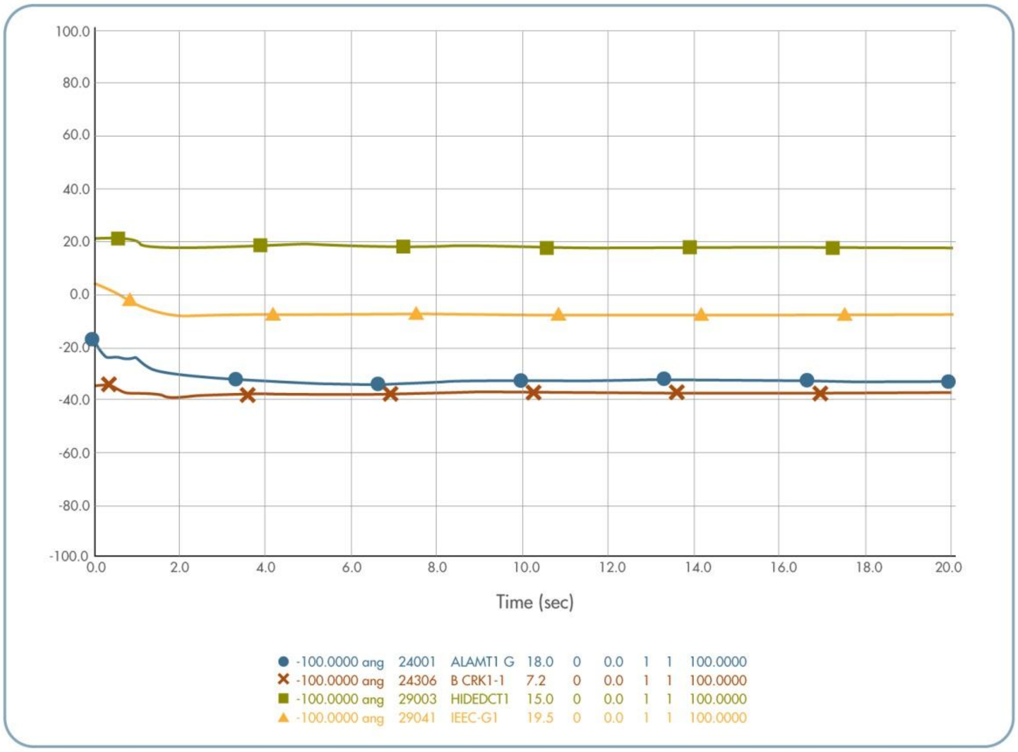


Figure 2.7.7-3: Rotor Angles in SCE for SONGS (G-2) Contingency (2021)

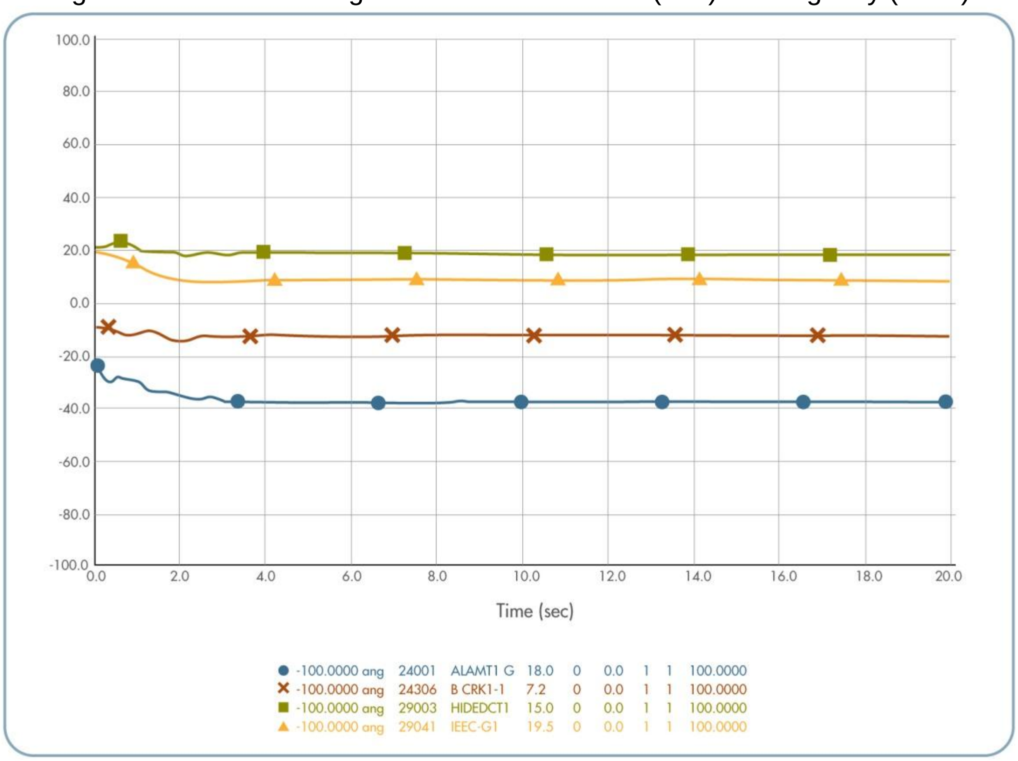


Figure 2.7.7-4: Contingency of SONGS unit #3 when unit #2 is off-line (2016 and 2021)

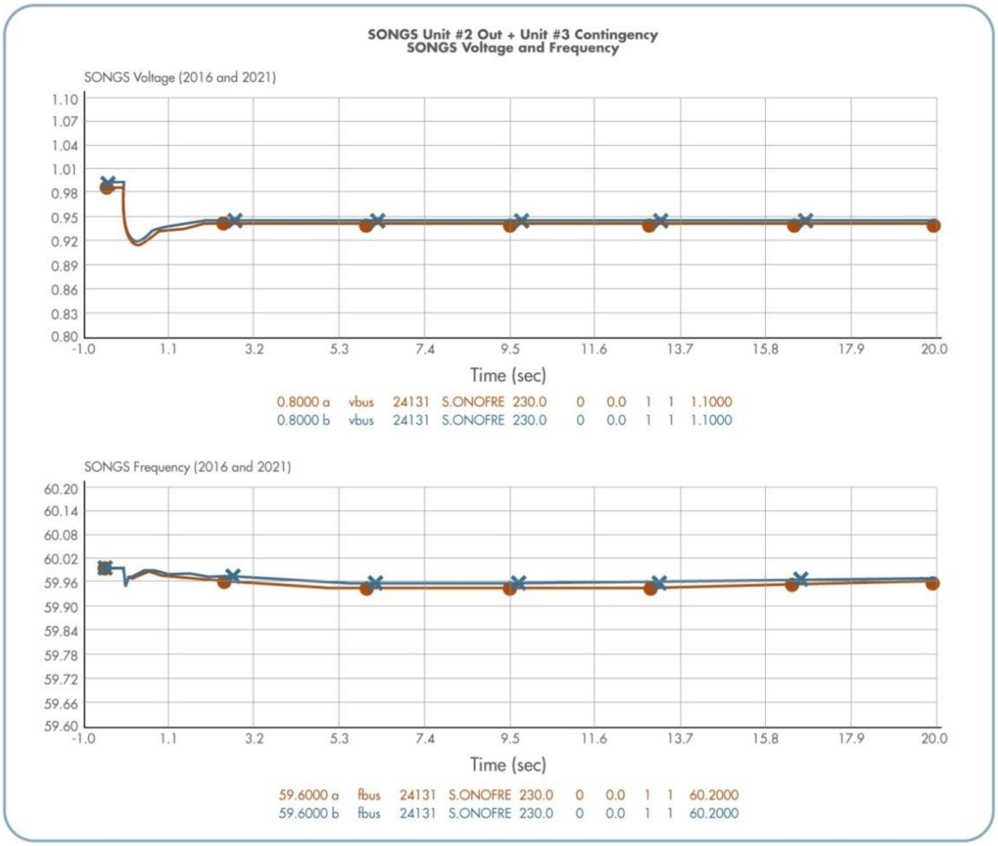


Figure 2.7.7-5: Bus Voltage & Frequency Lugo – Vincent (N-2) Contingency (2016 & 2021)

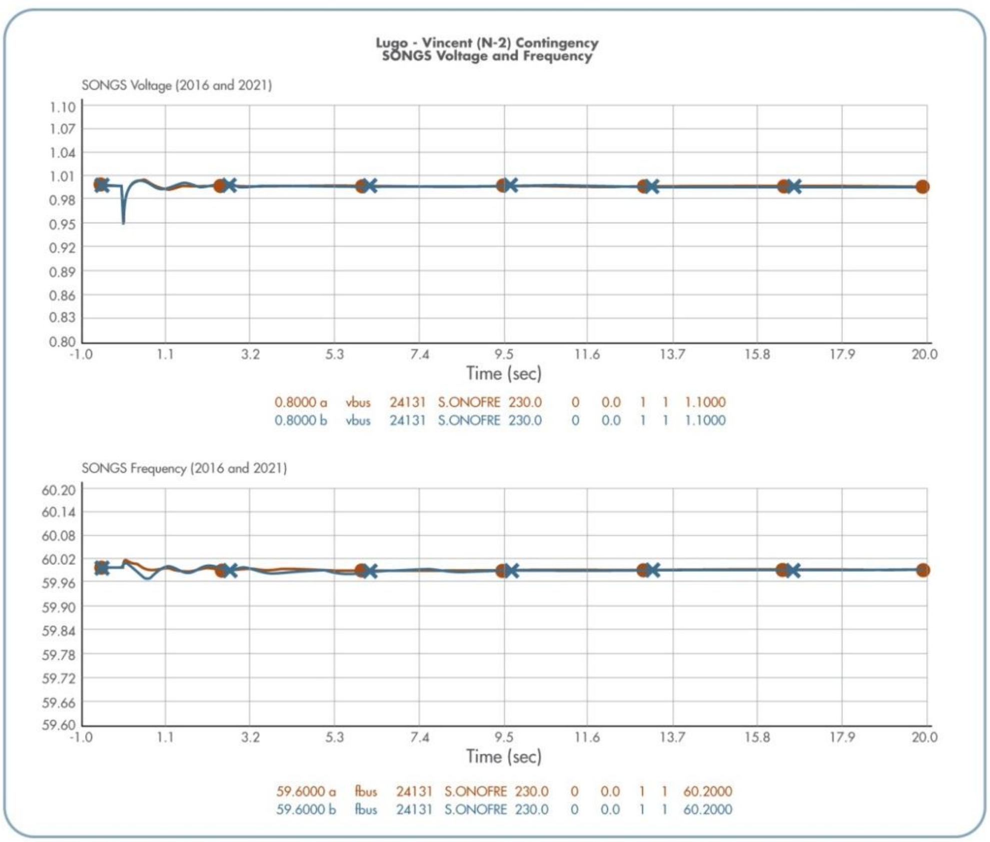
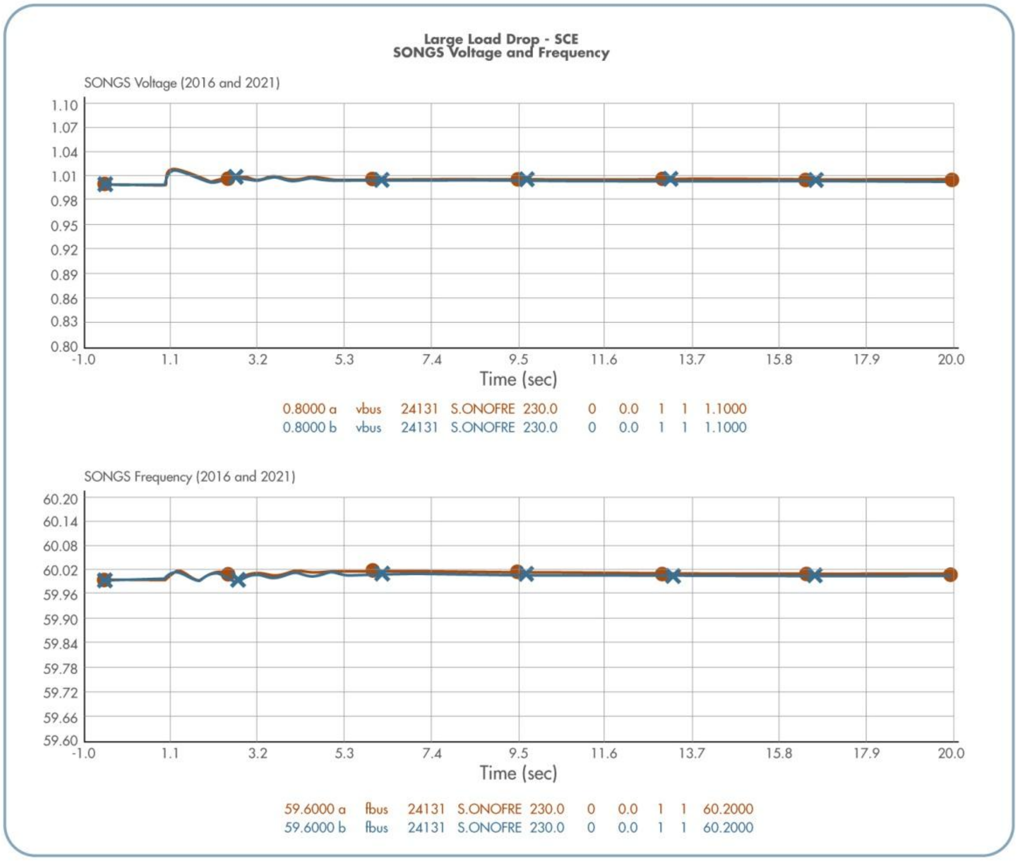


Figure 2.7.7-6: Bus Voltage and Frequency for Load Drop (2016 & 2021)



2.7.7.4 Recommended Solutions

Based on the 2012-2021 reliability assessment results of the Metro area, the ISO recommended solutions that address the issues found at each of the identified facilities that did not meet the thermal and voltage performance requirements under category A, B and C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were designed to ensure secure power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- reconfiguring 230 kV lines;
- adding shunt capacitors (optional); and
- developing or updating operating procedures.

Following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. This includes information about the expected in-service dates of the mitigation projects and plans.

2.7.7.4.1 Thermal Overload Mitigations

San Bernardino-Devers 230 kV line

The San Bernardino-Devers 230 kV line is loaded to 100 percent of its rating under normal conditions in the 2016 off peak case. The West of Devers transmission project, which has a target in-service date of December 2017, will address the loading concern beyond 2017. In the interim, loading on the line under normal conditions can be managed by re-dispatching generation in the LA Basin. The ISO will continue to monitor the loading concern in future planning cycles and will develop an operating procedure if expected loading on the line increases.

Mira Loma #1 & #2 500/230 kV banks and Chino-Mira Loma #3 230 kV line

The reliability assessment results indicate overloading on the Chino-Mira Loma #3 230 kV line following a T-1-1 contingency involving Mira Loma #1 and #2 500/230 kV transformers starting in 2012 and on the Mira Loma #1 or #2 500/230 kV transformer following a T-1/L-1 contingency involving either transformer and the Chino-Mira Loma #3 230 kV line starting in 2015.

Since the Chino-Mira Loma #3 230 kV line is planned to be upgraded as part of the Tehachapi Transmission Project with a target in-service date of Q3, 2015, mitigation measures to address the loading concern on the line are required for the 2012-2015 period. The ISO recommends updating the SCE operating procedure OP-104 to address this loading concern by June 1, 2012. The ISO has implemented OP 7580 effective February 2012 to manage loading on the Mira Loma 500/230 kV transformers.

Barre-Ellis 230 kV line

The Barre-Ellis 230 kV line was identified as overloaded beginning in 2012. SCE proposed to loop the existing Del Amo-Ellis 230 kV line into Barre to address the overloading of the Barre-Ellis line without having to shed upwards of 400 MW of load by 2015. The proposed project has a target in-service date of 2013. The ISO determined that this project is needed to mitigate the identified loading concerns. In the interim, the overload will continue to be mitigated by the existing Santiago N-2 RAS.

2.7.7.4.2 Voltage Concern Mitigation

Viejo 230 kV bus

Two alternatives were identified to address the low voltage and voltage deviation concerns at Viejo 230 kV bus. One alternative involves looping the San Onofre-Serrano 230kV line through Viejo. The other alternative involves adding a capacitor bank at Viejo. The ISO will identify the preferred development after further evaluation in the next planning cycle. Anticipated lead time for either alternative is not expected to jeopardize the required in-service date of May 2015.

2.7.7.4.3 Transient Voltage Dip Concern Mitigations

The voltage stability concern associated with a G-2 outage involving the two San Onofre units can be addressed by increasing generation in the LA Basin. The ISO has historically addressed this concern by maintaining minimum generation dispatch requirements in Southern California in accordance with the Southern California Import

Transfer (SCIT) Nomogram. No additional mitigation is considered necessary other than periodically updating and following established minimum generation requirements.

2.7.7.5 Key Conclusions

The 2012-2021 reliability assessment indicates several thermal, voltage and stability concerns in the Metro area of the SCE system under normal and various contingency conditions. The ISO recommends the following mitigation measures to address each of the identified reliability concerns:

- Initiate development of an operating procedure to manage loading on the San Bernardino-Devers 230 kV line under N-0 conditions in future planning cycles if loading on the line increases.
- Update SCE OP-104 to address loading on Chino-Mira Loma #3 230 kV line under category C conditions.
- Loop Del Amo-Ellis 230 kV line through Ellis to address the loading of Barre-Ellis 230 kV line under category C conditions.
- Loop the San Onofre-Serrano 230kV line through Viejo or add shunt capacitors at Viejo to address Viejo 230 kV low voltage and voltage deviation following a G-1/L-1 contingency. The preferred development will be identified in the 2012-2013 planning cycle.
- Dispatch generation in Southern California in accordance with established minimum generation requirements to prevent system instability following a San Onofre G-2 contingency.

The ISO received proposals for two transmission projects in the Metro area through the 2011-2012 Request Window. The ISO determined that the proposed projects are consistent with the ISO's mitigation solutions and are needed to mitigate an identified reliability concern. These projects are:

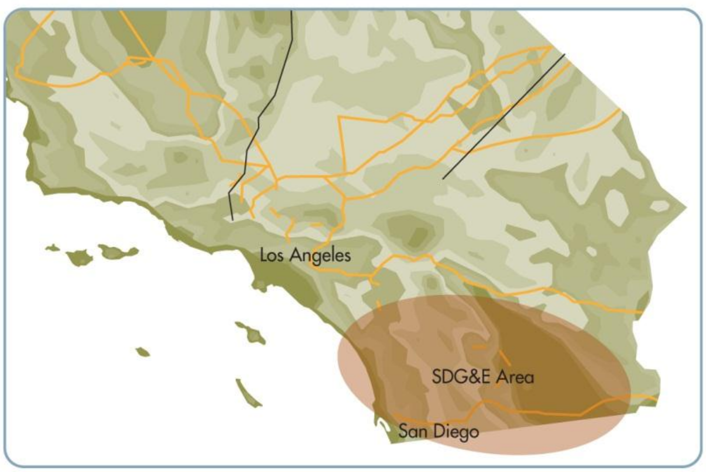
- Del Amo-Ellis 230 kV Line Loop-in Project, and
- Mesa 230 kV Breaker Upgrades Project.

2.8 San Diego Gas & Electric Area

2.8.1 Area Description

SDG&E is a public utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 830,000 natural gas meters in San Diego and southern Orange counties. The utility's service area encompasses 4,100 square miles from Orange County to the Mexican border.[19]

Presently, the SDG&E transmission system consists of the 500 kV Southwest Powerlink (SWPL) transmission line (North Gila-Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. When the Sunrise Powerlink Project is completed — presently scheduled for 2012 — SDG&E will have an additional 500 kV line from the Imperial Valley substation to central San Diego to serve its load. SDG&E uses both imports and internal generation to serve the load. The geographical location of the SDG&E system is shown in the adjacent illustration.



The existing points of import are the South of San Onofre (SONGS) transmission path (WECC Path 44), the Miguel 500/230 kV substation and the Otay Mesa-Tijuana 230 kV transmission line.

Historically, the SDG&E import capability was 2,850 MW with all facilities in-service and 2,500 MW with SWPL out-of-service. When the proposed Sunrise Powerlink project is built, the import cut-plane will change and will in turn affect the import capability.

In addition to import, the SDG&E area is served by local generation. Existing generation within the SDG&E system is composed of the following: combustion turbines; QFs; steam turbines at Encina; the combined cycle plants at Palomar Energy Center and Otay Mesa Energy Center; and, one wind farm. Only generation under construction or has received regulatory approvals was modeled.

The SDG&E transmission system consists of 500 kV SWPL transmission line (North Gila-Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. The 500 kV substations include Imperial Valley 500/230 kV and Miguel 500/230/138/69 kV.

The 230 kV system extends from the Talega substation and SONGS in Orange County in the north to the Otay Mesa Substation in the south near the Mexican border. 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego.

[19] These numbers are provided by SDG&E in the 2008 Transmission Expansion Plan

The 138 kV transmission system underlies the 230 kV system from the San Luis Rey 230/138/69 kV Substation in the north to the South Bay and Miguel substations in the south. There is also a radial 138 kV arrangement with five substations interconnected to the Talega 230/138/69 kV Substation in Orange County.

SDG&E sub-transmission system consists of numerous 69 kV lines arranged in a network configuration. Rural customers in the eastern part of San Diego County are served exclusively by a 69 kV system and often by long lines with low ratings.

2.8.2 Area-Specific Assumptions and System Conditions

The SDG&E area study was performed in accordance with the general study assumptions and methodology described in section 2.3. The ISO-secured website lists the contingencies that were evaluated as a part of this assessment. In addition, specific assumptions and methodology that applied to the SDG&E area study are provided below.

Generation

The studies performed for the heavy summer conditions assumed all available internal generation was being dispatched at full output except for Kearney peakers, which were assumed to be retired beyond 2014. The category B contingency studies were also performed for one generation plant being out-of-service. The largest single generator contingencies were assumed to be the whole Otay Mesa Energy Center or Palomar Energy Center. These two power plants are combined-cycle plants; therefore, there is a high probability of an outage of the whole plant. In addition to these generators, other generator outages were also studied.

Existing generation included all five Encina steam units, which were assumed to be available during peak loads. A total of 946 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit. Palomar Energy Center is owned by SDG&E and it began commercial operation in April 2006. This plant is modeled at 565 MW for the summer peak load reliability assessment.

The new combined cycle Otay Mesa power plant started commercial operation in October 2009. It was modeled in the studies with the maximum output of 603 MW.

There are several combustion turbines in San Diego. Cabrillo II owns and operates all but two of the small combustion turbines in SDG&E's territory. A total of 200 MW of generating capacity from the units was modeled as dispatched during peak summer conditions.

QFs were modeled with the total output of 180 MW. Power contract agreements with the QFs do not obligate them to generate reactive power. Therefore, to be conservative, all QF generation explicitly represented in power flow cases was modeled with a unity power factor assumption.

Existing peaking generation modeled in the power flow cases included the following: Calpeak Peakers located near Escondido (42 MW), Border (42 MW), and El Cajon (42 MW) substations; two Larkspur peaking units located next to Border Substation with summer capacity of 46 MW each; two peakers owned by MMC located near Otay

(35.5 MW) and Escondido (35.5 MW) substations; two SDG&E peakers at Miramar Substation (MEF) (46 MW each); and Cabrillo Power peakers at Miramar (36 MW aggregate) and El Cajon GT (13 MW). New peaking generation modeled in the studies included Orange Grove peakers and El Cajon Energy Center. The Orange Grove project, composed of two units (94 MW total), is connected to the 69 kV Pala Substation and started commercial operation in 2010. The El Cajon Energy Center, composed of one 48 MW unit, is connected to the 69 kV El Cajon Substation and started commercial operation in 2010.

Renewable generation included in the model for all the study years is the 50 MW Kumeyaay Wind Farm that began commercial operation in December 2005. Lake Hodges pump-storage plant (40 MW) is composed of two 20 MW units. The first unit started commercial operation in September 2011 and the second unit is expected to start commercial operation in March 2012. Additional renewable generation was modeled in all study years based on CPUC's discounted core and generation interconnection agreement status. These renewable generators were not dispatched in study cases for 2012 through 2016, but were dispatched in the 2021 case based on the hybrid portfolio. If any of these projects do not materialize, these units will not be modeled in future study cases.

In addition to the generation plants internal to San Diego, 1,070 MW of existing thermal power plants is connected to the 230 kV bus of the Imperial Valley 500/230 kV Substation.

SONGS was modeled with two units on line at maximum output for the summer peak load conditions.

Internal generation in San Diego modeled in the case is summarized in Table 2.8.2-1.

Table 2.8.2-1: Generation plants in the SDG&E area

Generation Plants	Max. Capacity (MW)	Note
Encina 1	106	-
Encina 2	103	-
Encina 3	109	-
Encina 4	299	-
Encina 5	329	-
Palomar	541	-
Otay Mesa	573	-
Encina GT	14	-
Kearny GT1	15	assumed retired
Kearny 2AB (Kearny GT2)	55	assumed retired
Kearny 3AB (Kearny GT3)	57	assumed retired
Miramar GT 1	17	-
Miramar GT 2	16	-
El Cajon GT	13	-
Goalline	48	-
Naval Station	47	-
North Island	33	-
NTC Point Loma	22	-
Sampson	11	-
NTC Point Loma Steam turbine	2.3	-
Ash	0.9	-
Cabrillo	2.9	-
Capistrano	3.3	-
Carlton Hills	1.6	-
Carlton Hills	1	-
Chicarita	3.5	-
East Gate	1	-
Kyocera	0.1	-
Mesa Heights	3.1	-
Mission	2.1	-
Murray	0.2	-
Otay Landfill I	1.5	-
Otay Landfill II	1.3	-
Covanta Otay 3	3.5	-

Generation Plants	Max. Capacity (MW)	Note
Rancho Santa Fe 1	0.4	-
Rancho Santa Fe 2	0.3	-
San Marcos Landfill	1.1	-
Shadowridge	0.1	-
Miramar 1	46	-
Larkspur Border 1	46	-
Larkspur Border 2	46	-
MMC-Electrovest (Otay)	35.5	-
MMC-Electrovest (Escondido)	35.5	-
El Cajon/Calpeak	42	-
Border/Calpeak	42	-
Escondido/Calpeak	42	-
El Cajon Energy Center	48	-
Miramar 2	46	-
Orange Grove	94	-
Kumeyaay (NQC)	8.3	-
Bullmoose (NQC)	27	-
Lake Hodges Pumped Storage	40	-

Load Forecast

Loads within the SDG&E system reflect a coincident peak load for 1-in-10-year heat wave conditions. The load for 2016 was assumed at 5,269 MW, and transmission losses were 131 MW. The load for 2021 was assumed at 5,598 MW, and transmission losses were 147 MW. SDG&E substation loads were assumed according to the data provided by SDG&E and scaled to represent assumed load forecast. The total load in the power flow cases was modeled based on the load forecast by the CEC. Table 2.8.2-2 summarizes load in SDG&E and the neighboring areas and SDG&E import modeled for the study horizon.

Table 2.8.2-2: Load, losses and import modeled in the SDG&E study

PTO	2012		2013		2014		2015		2016		2021	
	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW
SDG&E	4,751	131	5,073	138	5,154	125	5,212	132	5,269	131	5,598	147
SCE	25,585	501	25,585	496	27,449	419	27,021	406	28,041	459	29,415	460
IID	898	30	898	30	970	37	990	34	1022	43	1,156	100
CFE	2223	30	2,223	31	2820	35	2,763	32	2,760	37	3,387	51
SDG&E Import	3,299	-	3,303	-	3,311	-	3,300	-	3,305	-	3,293	-

Power flow cases for the study modeled a load power factor of 0.995 to 0.9981 lagging at nearly all load buses in 2012 and 2013. Study cases from 2013 to 2021 modeled a load power factor of 0.991 to 0.992 lagging. This number was used because supervisory control and data acquisition (SCADA)-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The 0.992 lagging value is based on historical system power factor during peak conditions. The exceptions listed below were modeled using power factors indicative of historical values. This model of the power factors was consistent with the modeling by SDG&E for planning studies. Periodic review of historical load power factor is needed to ensure that planning studies utilize realistic assumptions.

- Naval Station Metering (bus 22556): 0.707 lagging (this substation has a 24 MVar shunt capacitor);
- Creelman (bus 22152): 0.992 leading; and
- Descanso (bus 22168): 0.901 leading.

2.8.3 Study Results and Discussion

A summary of the study results of facilities in the SDG&E area under normal and various system contingency conditions is provided below.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one 230 kV transmission line was identified as overloaded with all facilities in service: Bay Boulevard-Miguel Tap 230 kV section of the Bay Boulevard-Miguel Tap-Otay Mesa 230 kV line. The ISO studies showed an overload above the normal rating starting in 2021.

None of the buses demonstrated voltages below or above the limits specified in the reliability criteria under category A performance requirements.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

For the summer peak cases, 18 facilities were identified with thermal overloads for contingencies of a single transmission facility or a single transmission facility with one generator out-of-service. The overloaded facilities are listed below:

- Bernardo-Rancho Carmel 69 kV line
- El Cajon-Los Coches 69 kV line
- Japanese Mesa-Talega Tap kV line
- Oceanside Tap-Stuart Tap kV line
- Pendleton-San Luis Rey kV line
- Morro Hill Tap-Melrose kV line
- Penasquitos-Torrey Pines kV line
- San Ysidro-Otay Tap kV line
- Sweetwater-Montgomery Tap kV line
- Sweetwater-Sweetwater Tap kV line
- Talega-Talega Tap kV line
- Pomerado-Sycamore 69 kV line #1
- Pomerado-Sycamore 69 kV line #2
- Poway-Pomerado 69 kV line
- San Ysidro-Otay Lake Tap kV line
- Sycamore-Scripps kV line
- Torrey Pines-Dunn Hill Tap kV line.

These overloads and the proposed mitigation measures are summarized in Appendix A.

One line identified in the peak cases was also overloaded in the off-peak cases: El Cajon-Los Coches 69 kV line.

Under peak load conditions, two 69 kV load buses were identified with voltages below or above the limits specified in the reliability criteria under category B contingency conditions. Nine load buses with voltage deviations were identified under category B contingency conditions.

The following buses had low voltage for category B contingencies:

- Avocado 69 kV
- Pendleton 69 kV

The following buses had large voltage deviations:

- Boulevard 69 kV
- Cannon 138 kV
- Horno 69 kV
- Las Pulgas 69 kV
- Monserate 69 kV
- Narrows 69 kV
- North City 69 kV
- Pendleton 69 kV
- Poway 69 kV.

Under off-peak load conditions, no load buses were identified with voltages below or above the limits specified in the reliability criteria under category B contingencies. Five load buses with voltage deviations were identified as not meeting the requirements under category B contingencies.

The following buses had large voltage deviations:

- Boulevard 69 kV
- Mesa Rim 69 kV
- Narrows 69 kV
- Crestwood 69 kV
- Kumeyaay 69 kV.

These voltage concerns and the proposed mitigation measures are summarized in Appendix A.

TPL 003: System Performance Following Loss of Two or More BES Elements

Category C contingencies studied included:

- Outage of a single transmission facility with generation adjusted followed by another single facility outage (N-1-1);
- Outage of two transmission lines in the same corridor (N-2);
- Stuck circuit breaker; and
- Outage of a bus or a bus section.

For the summer base cases, 164 facilities were identified with thermal overloads for category C contingencies. These overloads and the proposed mitigation measures are summarized in Appendix A.

Twenty-seven buses experienced voltages below or above the requirements for category C contingencies, and twenty-eight buses had voltage deviations that did not meet the criteria requirements.

All of the overloads observed in the analysis of the off-peak case were already seen in the peak case analysis.

TPL 004: System Performance under Extreme Events

As a category D contingency, a common corridor outage of the transmission lines north of Miguel was studied. Transmission lines in the North-of-Miguel corridor include:

- Miguel-Sycamore Canyon 230 kV;
- Miguel-Mission #1 and #2 230 kV;
- Otay Mesa-Sycamore Canyon 230 kV;
- Miguel-Los Coches 138 kV and 69 kV; and
- Miguel-Jamacha #1 and #2 69 kV.

The case converged with no indication of cascading failures or major overloads for the system conditions studied.

Another common corridor contingency involving more than two transmission circuits is an outage of transmission lines from San Onofre to San Luis Rey. This transmission corridor includes San Onofre-San Luis Rey 230 kV #1, #2 and #3.

The studies of this common corridor category D contingency for the peak summer conditions of 2021 showed that there would be no cascading contingencies and no overloads for the system conditions studied.

Category D contingencies of loss of major power plants in SDG&E were also run as part of the reliability assessment. Loss of Otay Mesa, Palomar, Encina and SONGS generation plants were tested one at a time. These extreme contingencies did not show a possibility of cascading contingencies.

NUC-001: System Performance under Scenarios that Can Affect SONGS

The technical studies were conducted in compliance with the NUC-001-2 standard and the Nuclear Plant Interface Requirements for the San Onofre Nuclear Generating Station, and per the requirements of ISO tariff section 24 and the Business Practice Manual for Transmission Planning Process. The planning analyses are conducted annually. The consolidated Southern California base cases with a 1-in-5 load forecast were used to perform the studies.

Post transient governor power flow and transient stability studies were conducted to assess the performance related to SONGS under normal and emergency conditions. In the planning cycle conducted during 2011, the planning studies were conducted for multiple years from 2012 to 2021. The 2016 and 2021 summer peak scenarios were used to test system performance: The ISO ran several contingencies for thermal, voltage and stability concerns. These contingencies included the following:

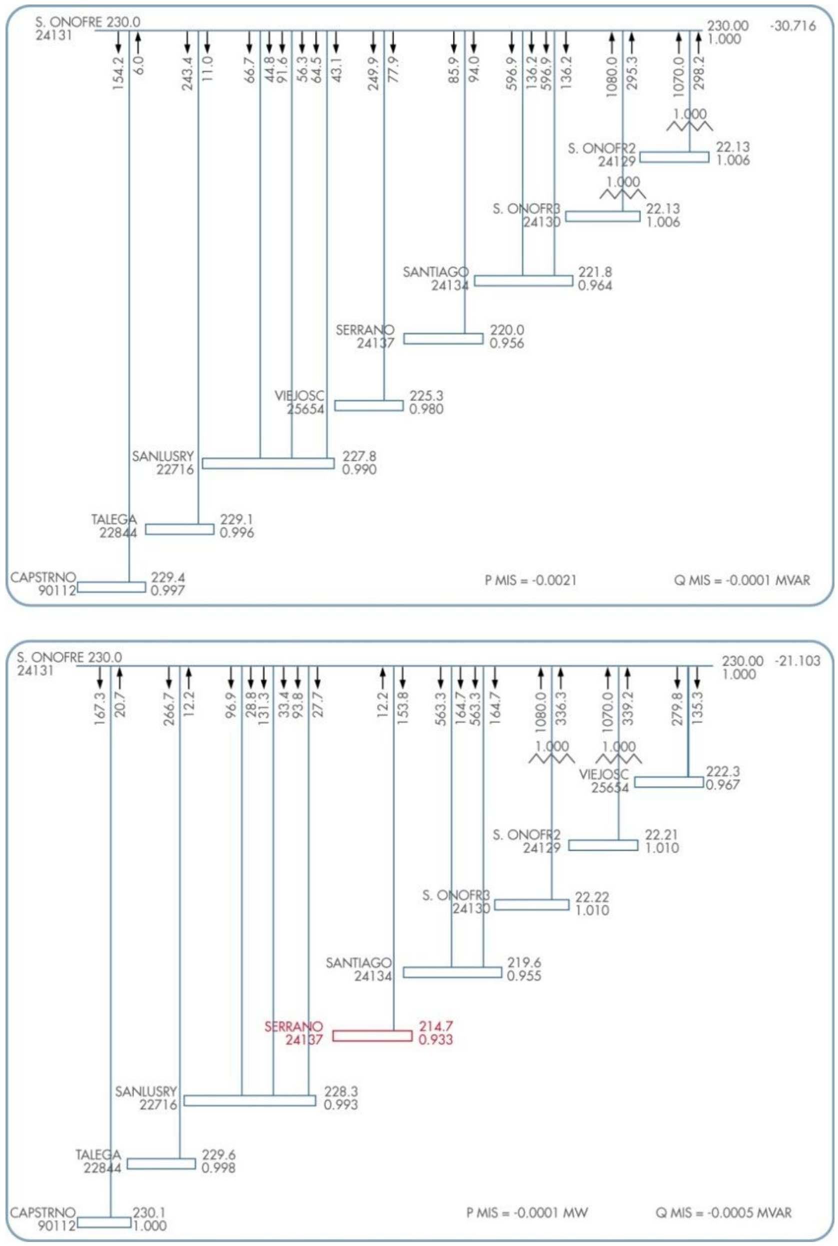
- loss of a single SONGS unit (G-1);
- loss of both SONGS units (G-2);
- loss of a single SONGS unit with the other unit already off-line (G-1-1);
- all critical contingencies of transmission lines connected to SONGS (category B, C and D);
- loss of major generation plants in the SDG&E area;

- loss of critical transmission lines and interties in the SDG&E system;
- critical bus section contingencies in the SDG&E area; and
- loss of entire load at Bernardo Substation (largest load block in the service territory) according to the information provided in the base case).

The base cases modeled all transmission circuits connected to SONGS switchyard with the status normally in service. The study results showed the following:

- The steady state voltage at SONGS 230 kV switchyard was 230 kV under 2016 summer peak conditions and 230 kV under 2021 summer peak conditions (refer to Figure 2.8.3-1). This is within the range specified in the NPIRs and in Appendix E of the Transmission Control Agreement for SONGS (218 kV to 234 kV).
- The SONGS generator is regulating the 230kV bus voltage to 1.00 per unit in the 2016 summer peak case and in the 2021 summer peak case.

Figure 2.8.3-1: SONGS 230kV bus voltage (2016 and 2021)



The study results from various studies show that there are no thermal overloads or transient stability concerns related to the SONGS units under normal or emergency conditions. In 2021, SONGS G-2 contingency results in post-transient divergence. This can be mitigated by increasing generation in the LA Basin. The ISO has historically addressed this concern by maintaining minimum generation dispatch requirements in Southern California in accordance with the SCIT Nomogram. No additional mitigation is considered necessary other than periodically updating and following established minimum generation requirements.

The following plots for two of the most severe contingencies and for a sudden loss of load demonstrate that there are no stability concerns related to the SONGS units.

Figure 2.8.3-2: Rotor angles in SDG&E for SONGS (G-2) contingency (2016)

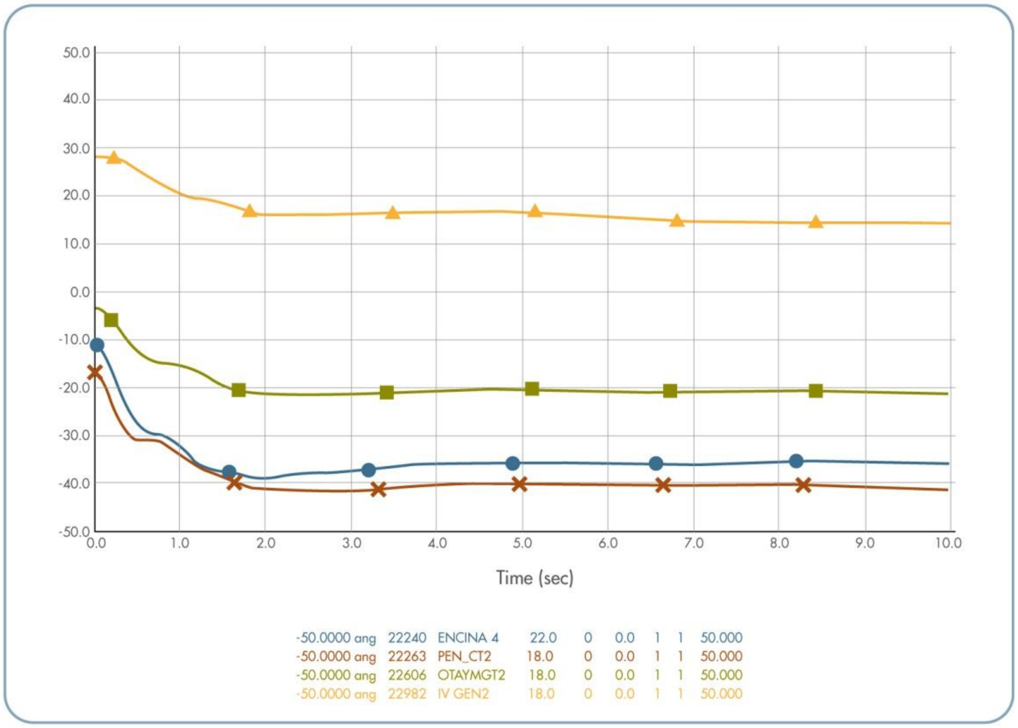


Figure 2.8.3-3: Rotor angles in SDG&E for SONGS (G-2) contingency (2021)

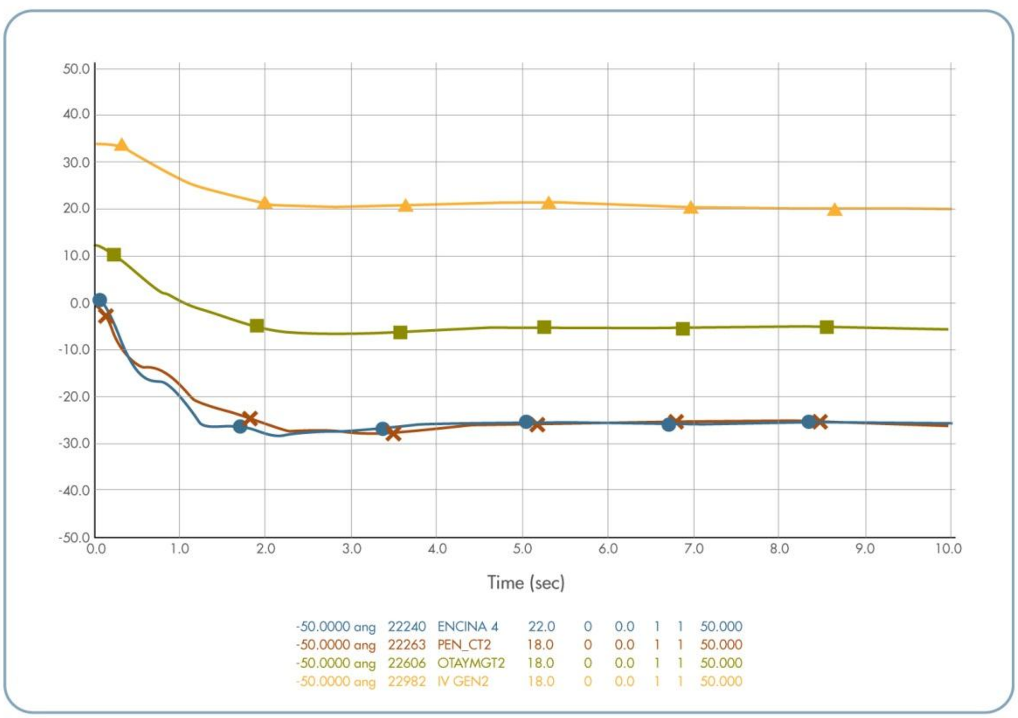


Figure 2.8.3-4: Loss of SONGS unit #3 when unit #2 is off-line (2016 & 2021)

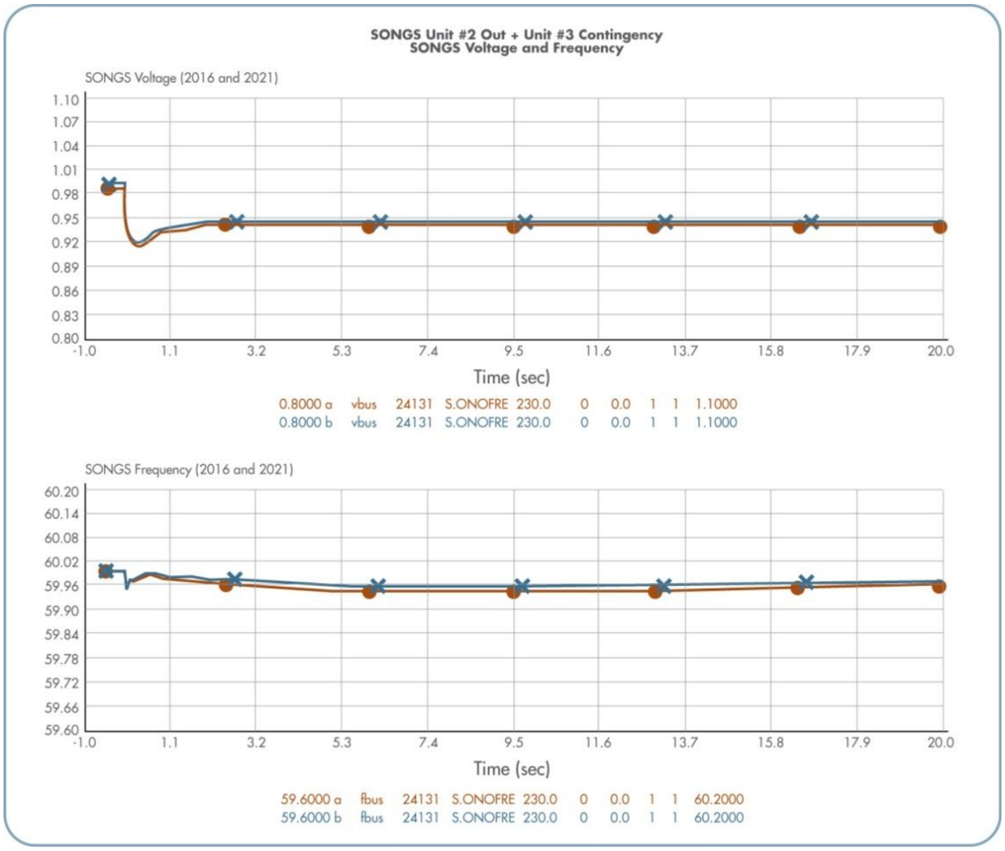


Figure 2.8.3-5: Loss of Southwest Power Link (2016 and 2021)

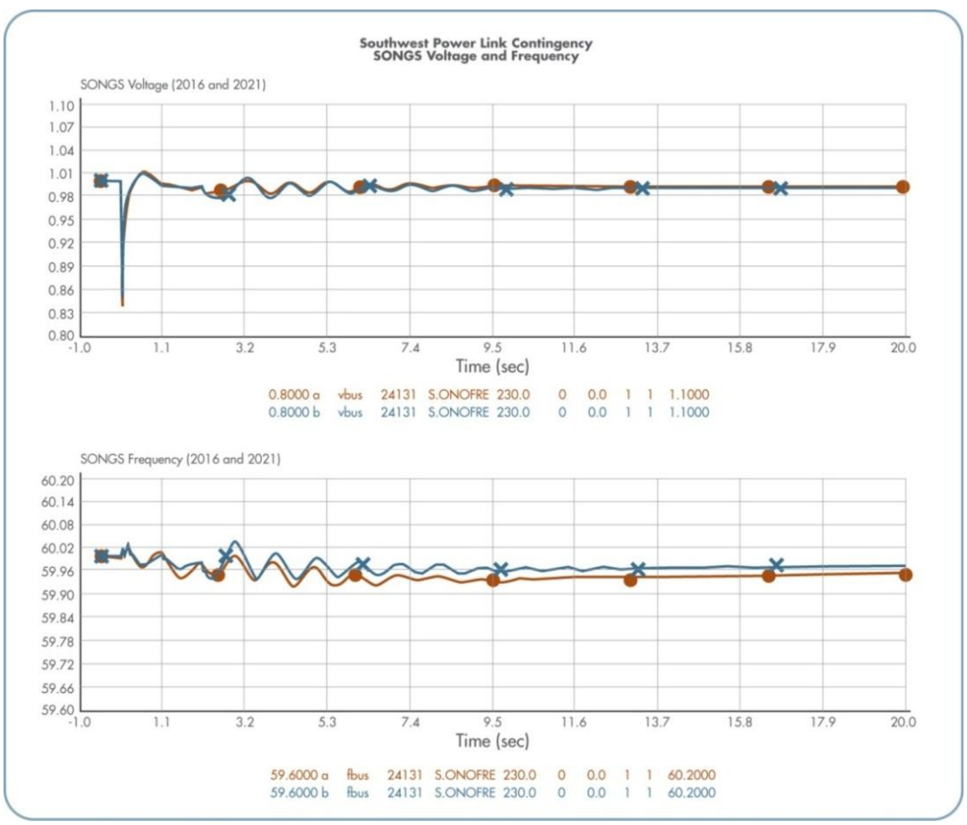


Figure 2.8.3-6: Loss of Southwest Power Link and Sunrise Power Link (2016 and 2021)

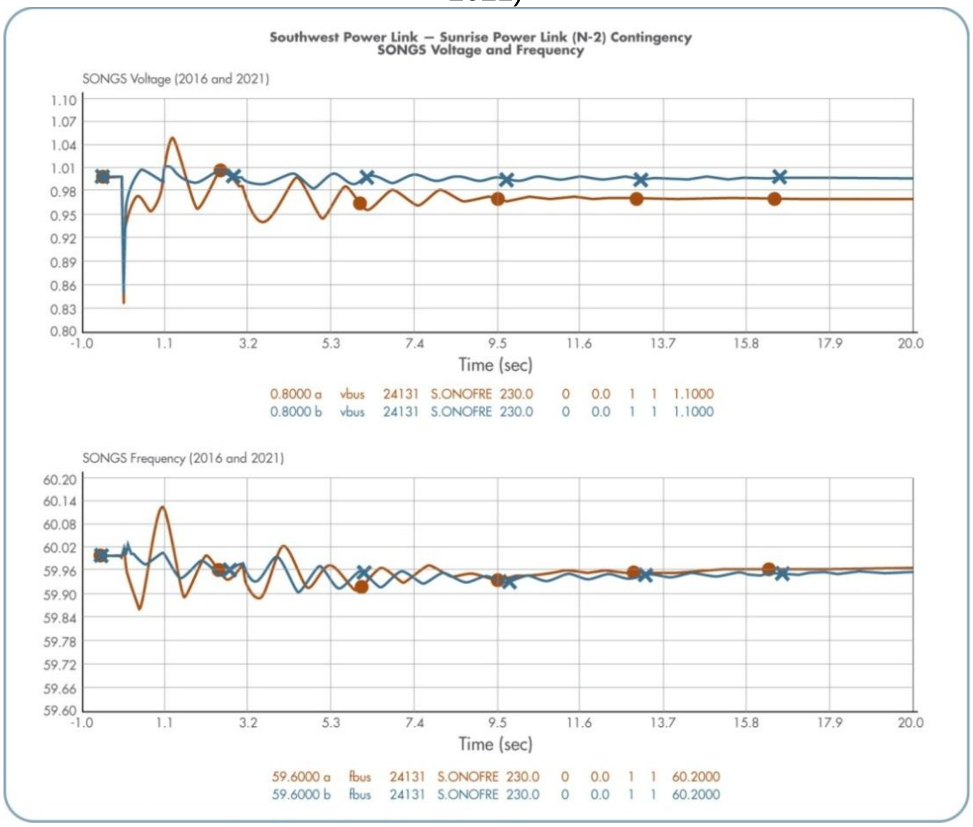
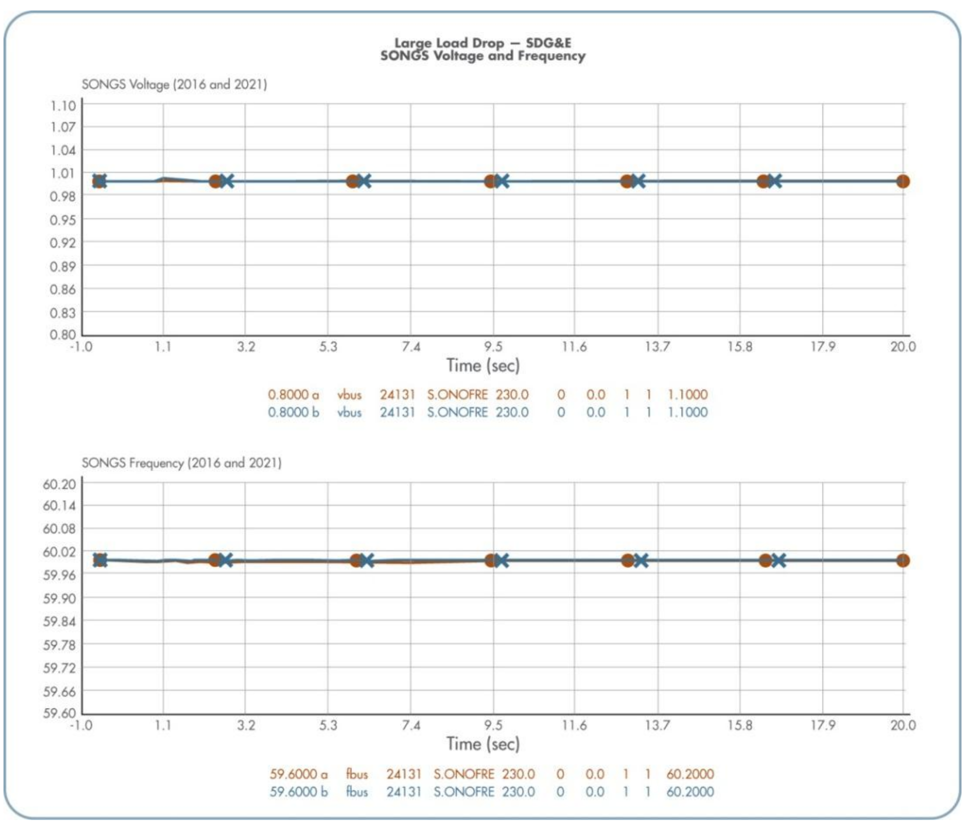


Figure 2.8.3-7: Bus voltage and frequency under sudden loss of load (2016 and 2021)



Transient Stability Studies

All major 500 kV and 230 kV contingencies were studied for 2021. Scenarios analyzed included critical category B, C and D contingencies based on historical and expected operation. Three-phase faults were modeled on the sending end bus of the transmission lines. Fault duration was modeled as four cycles for 500 kV and six cycles for 230 kV. The faults were cleared by opening the lines. The contingencies that were studied included the following:

- Imperial Valley-Miguel 500 kV with and without CFE cross trip;
- Hassayampa-North Gila 500 kV;
- Imperial Valley-North Gila 500 kV;
- Imperial Valley-Suncrest 500 kV (planned);
- Imperial Valley-Miguel 500 kV and Imperial Valley-Suncrest 500 kV;
- Sycamore-Suncrest 230 kV (planned) #1 and #2;
- Miguel-Mission #1 and #2;
- Palomar-Escondido #1 and #2 230 kV;
- Palomar-Encina 230 kV;
- SONGS generator #2;
- Palo Verde generator #2;
- SONGS generators #2 and #3; and
- Palo Verde generator #1 and #2.

North of Miguel category D outage studies simulated a three-phase six-cycle fault on the Miguel 230 kV bus cleared by opening all transmission lines north of Miguel: Miguel-Sycamore Canyon 230 kV; Miguel-Mission #1 and #2 230 kV; Otay Mesa-Sycamore Canyon 230 kV; Miguel-Los Coches 138 kV and 69 kV; and Miguel-Jamacha #1 and #2 69 kV. The study showed that the system was stable with acceptable transient stability performance.

Post Transient and Voltage Stability Studies

Post-transient studies identified case divergence for the following outages:

- Imperial Valley-Miguel 500 kV with CFE cross trip;
- Imperial Valley-Miguel 500 kV and Imperial Valley-Suncrest 500 kV; and
- SONGS generators #2 and #3.

Voltage stability analysis for 2016 and 2021was also performed for the category D outage of North of Miguel. This contingency did not show any need for additional reactive support and did not result in any overloads or under-voltage problems.

Impact of the SDG&E Contingencies on the Neighboring Systems

Historically, Imperial Valley-Miguel 500 kV outage caused overloads in the CFE, and IID systems. These overloads are mitigated by tripping all generation units connected to the Imperial Valley 230 kV bus and cross tripping either Imperial Valley-La Rosita or

Otay Mesa-Tijuana 230 kV lines in case of overload using an automatic SPS. Addition of the *Sunrise Powerlink Project* will reduce loading concerns in the CFE and IID systems with the Imperial Valley-Miguel outage. However, a Category C outage of Sunrise Powerlink and Imperial Valley-Miguel requires similar RAS. Therefore, the ISO recommends revision of the existing RAS when the *Sunrise Powerlink Project* comes into service to include this Category C outage and appropriate RAS actions.

2.8.4 Recommended Solutions

This section shows study results and proposed mitigation plans for the San Diego area under each category of the planning standards.

2012 through 2016 SDG&E Area Assessment Summary

For the overall transmission and sub-transmission systems, the first five years of studies identified the following needs:

- strengthen Bernardo 69 kV area;
- strengthen El Cajon 69 kV area;
- mitigate overloads and voltage issues in Pendleton 69 kV area;
- mitigate overloads and voltage issues in Orange County 69 kV system; and
- mitigate Sycamore area overloads using generation.

2021 SDG&E Area Assessment Summary

For the overall transmission and sub-transmission systems, in addition to the upgrades and mitigations listed in the 2016 studies, the 2021 studies identified the following needs:

- mitigate Bay Boulevard – Miguel Tap 230kV normal overload;
- mitigate Sweetwater 69kV area overloads; and
- mitigate Penasquitos, Torrey Pines 69kV area overloads.

The study evaluated system reliability under NERC, WECC and the ISO category A, B, C and D contingencies.

TPL 001: System Performance under Normal Conditions

For the summer peak cases, one 230 kV transmission line (Bay Boulevard-Miguel Tap 230 kV line) is expected to overload with all facilities in service. This overload shows only in 2021. The overload can be mitigated by generation re-dispatch near the Otay Mesa area. Miguel Tap reconfiguration (which will create Bay Boulevard – Miguel 230 kV line, two Otay Mesa – Miguel 230kV lines and an additional Miguel – Sycamore 230 kV line) is a potential mitigation for this overload. This reconfiguration is needed for Cluster 1 and Cluster 2 projects (pending LGIA). Since the overload shows up in 2021 in the reliability assessment, the need for this reconfiguration will be evaluated in the next planning cycle.

No buses with voltage below the specified limits were found under the category A performance requirements. Several buses with voltages higher than 1.05 pu were observed. Adjustments in voltage schedules, appropriate tap adjustments and use of voltage control devices can mitigate these high voltage issues.

TPL 002: System Performance Following Loss of a Single BES Element

Power flow studies were performed for N-1 conditions (category B) with all major power plants in service and for N-1, G-1 conditions with the Otay Mesa or Palomar Energy Center generation out. Outage of the Otay Mesa power plant is the largest G-1 contingency in San Diego. Each of the category B contingencies were studied for 2012-2016 as well as for 2021. The power flow studies of category B contingencies identified the following overloads.

500/230 kV System

No overloads or under voltage issues were identified on the 500 kV and 230 kV system. High voltages greater than 1.05 p.u. were observed at multiple 500 kV buses, including Imperial Valley, North Gila and Suncrest. These high voltages are exempted based on SDG&E's voltage control standard, which allows up to 1.1 p.u. voltages on the 500 kV system.

Voltage deviation greater than 5 percent was identified at Suncrest 500 kV bus for the contingency of Southwest Power Link only in 2021. The ISO recommends further evaluation in future planning cycle.

138 kV System

No overloads or under voltage issues were identified on the 138 kV system. Voltage deviations greater than 5 percent were observed at the Boulevard and Cannon buses. Both of these can be mitigated by adjusting taps at Boulevard and Cannon respectively.

TL13820, Sycamore-Chicarita 138 kV Line

Reliability assessment did not identify any overload on this facility. SDG&E submitted a project to reconductor this line — TL13820, Sycamore-Chicarita Reconductor. The ISO has determined that this reliability project is not needed.

69 kV System

TL633, Bernardo-Rancho Carmel 69 kV Line

This line is expected to be overloaded for an outage of TL6913, Poway-Rancho Carmel 69 kV line starting in 2015. Generation available to mitigate this overload will not be sufficient beyond 2016. SDG&E submitted a project to reconductor this line — TL633, Bernardo-Rancho Carmel 69 kV: Reconductor. The ISO has determined that this reliability project is needed.

TL631, El Cajon-Los Coches 69 kV line

This line is expected to be overloaded for an outage of TL632, Miguel-Granite-Los Coches 69 kV line starting in 2013. Generation at El Cajon can mitigate this issue, but one of the gas turbines at El Cajon will retire by 2014 and the remaining generation will not be sufficient to mitigate this issue. SDG&E submitted a project to reconductor this line — Reconductor TL631, El Cajon-Los Coches. The ISO has determined that this reliability project is needed.

TL695B, Japanese Mesa-Talega Tap 69 kV line

This line is expected to be overloaded for an outage of TL690, San Luis Rey-Oceanside-Stuart-Las Pulgas 69 kV line starting in 2016. There is no generation available to mitigate this overload. SDG&E submitted a project to reconductor this line — TL695B, Talega Tap – Japanese Mesa Reconductor. The ISO has determined that this reliability project is needed.

TL690C, Oceanside Tap-Stuart Tap 69 kV line

This line is expected to be overloaded for an outage of Talega 138/69 kV bank 50 starting in 2021. There is no generation available to mitigate this overload. SDG&E submitted a project to reconductor this line — TL690C, Oceanside Tap-Stuart Tap Reconductor. The ISO will consider this as a conceptual mitigation. Since the overload observed in 2021 is only 1 percent, the ISO recommends further evaluation in a future planning cycle.

TL695A, Talega-Talega Tap 69 kV line

This line is expected to be overloaded for an outage of TL690, San Luis Rey-Oceanside-Stuart-Las Pulgas 69 kV line starting in 2015. There is no generation available to mitigate this overload. The actual limiting element is Talega 138/69 kV bank 50. Because of the limitation on this bank, TL695A is rated lower than its actual rating of 137 MVA. SDG&E submitted a project to upgrade Talega bank 50 — 'Replace Talega 138/69 kV Bank 50'. The ISO has determined that this reliability project is needed.

TL6912, Pendleton-San Luis Rey 69 kV line

This line is expected to be overloaded for an outage of TL694, Moserate-Morro Hill Tap-Melrose 69 kV line starting in 2016. There is generation available to mitigate this overload. Generation dispatch will be required only above 98 percent of the 1-in-10 peak load in 2021. SDG&E submitted multiple projects, each one of which can fix this problem. The projects are as follows:

- a reconductor, TL6912, Pendleton – San Luis Rey Reconductor;
- a new line, TL69XX, Melrose – Monserate; and
- a new line, New TL69XX San Luis Rey – Monserate 69 kV Line.

Since there is enough generation available to mitigate this problem by dispatching it through the ISO market mechanism and this generation is expected to be required only under super-peak conditions, the ISO recommends relying on local generation dispatch through ISO market mechanism to mitigate this overload. Hence, the ISO has determined that these three reliability projects are not needed.

TL694A, Morro Hill Tap-Melrose 69 kV line

This line is expected to be overloaded for a L-1/G-1 outage of TL6912, Moserate-Morro Hill Tap-Melrose 69 kV line plus Palomar generation starting in 2015. There is generation available to mitigate this overload. Generation dispatch will be required only above 94 percent of the 1-in-10 peak load in 2021. SDG&E submitted multiple projects, each one of which can fix this problem. The projects are as follows:

- reconductor, TL694A Morro Hill Tap–Melrose Reconductor;
- new line, TL69XX, Melrose–Monserate;
- new line, New TL69XX San Luis Rey–Monserate 69 kV Line.

Since there is enough generation available to mitigate this problem by dispatching it through the ISO market mechanism and this generation is expected to be required only under a very high-peak conditions, the ISO recommends relying on generation to mitigate this overload. Hence, the ISO has determined that these three reliability projects are not needed.

TL662, Penasquitos-Torrey Pines 69 kV line

This line is expected to be overloaded for an outage of TL666, Penasquitos-Del Mar-Doublett-Dunhill-Torrey Pines 69 kV line starting in 2021. SDG&E submitted a project to reconductor this line — TL662, Penasquitos-Torrey Pines. The ISO will consider this as a conceptual mitigation. Since the overload observed in 2021 is only 2 percent, the ISO recommends further evaluation in a future planning cycle.

TL642B, Sweetwater-Montgomery Tap 69 kV line

This line is expected to be overloaded for an outage of TL23026, Silvergate-Bay Boulevard 230 kV line starting in 2021. SDG&E submitted a project to implement terminal equipment adjustments to CTs (current transformers) and relays — TL642B, Sweetwater-Montgomery Tap–Terminal Equipment. The rating increase implemented by this project will not be enough to mitigate the overload in 2021. Miguel Tap reconfiguration (which will create Bay Boulevard-Miguel 230 kV line, two Otay Mesa-Miguel 230 kV lines and an additional Miguel-Sycamore 230 kV line) is a potential mitigation for this overload. This reconfiguration is needed for Cluster 1 and Cluster 2 projects (pending LGIA). Since the overload shows up in 2021 in reliability assessment, the need for this reconfiguration will be evaluated in the next planning cycle.

TL642B, Sweetwater-Sweetwater Tap 69 kV line

This line is expected to be overloaded for an outage of TL23026, Silvergate-Bay Boulevard 230 kV line starting in 2021. Miguel Tap reconfiguration (which will create Bay Boulevard-Miguel 230 kV line, two Otay Mesa-Miguel 230 kV lines and an additional Miguel-Sycamore 230 kV line) is a potential mitigation for this overload. This reconfiguration is needed for Cluster 1 and Cluster 2 projects (pending LGIA). Because the reliability assessment shows overload in 2021, the need for this reconfiguration will be evaluated in the next planning cycle.

TL6916, Sycamore-Scripps 69 kV line

This line is expected to be overloaded for a L-1/G-1 outage of TL23042A, Otay Mesa-Bay Boulevard 230 kV line plus SONGS unit #3 starting in 2015. SDG&E submitted two projects which can mitigate this issue. The projects are as follows:

- a new line, TL6942, New Line from Sycamore Canyon-Miramar; and
- substation expansion, Expand Los Coches Substation to 230 kV

There is enough generation available at Miramar to mitigate this overload beyond 2016 but not in 2021. In addition to generation dispatch, Miguel Tap reconfiguration (which will create Bay Boulevard-Miguel 230 kV line, two Otay Mesa-Miguel 230 kV lines and an additional Miguel-Sycamore 230 kV line) is also a potential mitigation for this overload, which can last beyond 2021. This reconfiguration is needed for Cluster 1 and Cluster 2 projects (pending LGIA). Because of the timing uncertainty with regards to Miguel Tap Reconfiguration, the ISO recommends relying on generation dispatch mitigation in the short term and further evaluation in a future planning cycle.

TL6915 and TL6924, Pomerado-Sycamore #1 and #2 69 kV line

TL6915 and TL6924 are two parallel lines. Either one of these lines are expected to be overloaded for a L-1/G-1 outage of the other line plus Palomar generation starting in 2014. Since sufficient generation is available to mitigate the overloads, the ISO recommends relying on generation dispatch for solving these issues.

TL6913, Poway-Pomerado 69 kV line

This line is expected to be overloaded for a L-1/G-1 outage of TL6908, Escondido-Esco 69 kV line plus Goalline generation starting in 2012. A project to reconductor this line was previously approved. The new rating was planned to be 148 MVA. SDG&E confirmed that the rating will be 174 MVA. This will be sufficient to mitigate this overload until 2021.

TL623C, San Ysidro-Otay Tap 69 kV line

This line is expected to be overloaded for an outage of TL649B, Border-Otay-San Ysidro 69 kV line starting in 2021. There is enough generation available to mitigate this overload. The ISO will also consider a conceptual mitigation to reconductor this line. Since the overload observed in 2021 is only 0.6 percent, the ISO recommends further evaluation in a future planning cycle.

TL649D, San Ysidro-Otay Lake Tap 69 kV line

This line is expected to be overloaded for a L-1/G-1 outage of TL623, Imperial Beach-Otay-San Ysidro 69 kV line plus SONGS unit #3, starting in 2021. The ISO will consider reconductoring this line as a conceptual mitigation. Since the overload observed in 2021 is only 1 percent, the ISO recommends further evaluation in a future planning cycle.

TL666B, Torrey Pines-Dunhill Tap 69 kV line

This line is expected to be overloaded for a L-1/G-1 outage of TL662, Penasquitos-Torrey Pines 69 kV line plus SONGS unit #3 starting in 2021. The ISO will consider reconductoring this line as a conceptual mitigation. Since the overload observed in 2021 is only 1 percent, the ISO recommends further evaluation in a future planning cycle.

TL649A, Otay-Otay Lake Tap 69 kV line

Reliability assessment performed by the ISO did not identify any overload on this facility. SDG&E submitted a project to reconductor this line — Reconductor TL649A, Otay–Otay Lake Tap. The project submission indicates that the line may be overloaded for the outage of TL6910, Miguel-Border 69 kV line, starting in 2018. Sufficient generation is available to mitigate this overload. The ISO recommends further evaluation in a future planning cycle.

TL680B, Melrose-Melrose Tap 69 kV line

Reliability assessment performed by the ISO did not identify any overload on this facility. SDG&E submitted a project to reconductor this line — TL680B, Melrose-Melrose Tap: Reconductor. The project submission indicates that the line may be overloaded for the outage of TL693, San Luis Rey-Melrose 69 kV line, starting in 2013. A previously approved Melrose Loop-in Project mitigates this overload. Hence, the ISO has determined that this reliability project is not needed.

69 kV Voltage Issues

Avocado 69 kV and Pendleton 69 kV buses are expected to experience voltages lower than 0.95 p.u. for a L-1/G-1 outage of TL6912, Pendleton-San Luis Rey plus SONGS unit #2. Adjusting taps at Talega and Escondido can mitigate these low voltages.

In the Southern Orange County 69 kV system, Horno and Las Pulgas 69 kV buses experience voltage deviations greater than 5 percent for the outage of TL690, San Luis Rey-Oceanside, Stuart-Las Pulgas 69 kV line. A project to upgrade Talega 138/69 kV bank 50 is found to be needed in this reliability assessment. This bank with on-load tap changers can mitigate the voltage deviation issue.

In Pendleton 69 kV system, Monserate, Avocado and Pendleton 69 kV buses experience voltage deviations greater than 5 percent for the outage of TL6912, Pendleton-San Luis Rey 69 kV line. These deviations can be mitigated by tap adjustments at Talega and Escondido. In 2021, generation at Pala can be used to mitigate the 5 percent deviations.

North City West 69 kV bus experiences voltage deviation greater than 5 percent for the outage of TL6952, North City-Penasquitos 69 kV line. This deviation issue can be mitigated by adjusting taps at San Luis Rey.

The eastern 69 kV system already has several capacitors and yet it is expected to experience many voltage deviation issues. Installing more capacitors will fix the deviation problem, but it can create other vulnerabilities, such as a high voltage collapse point. The ISO recommends using voltage schedule adjustments and tap setting to mitigate voltage issues on the 69 kV system. In addition, the ISO recommends further evaluation in a future planning cycle to determine a permanent fix for these problems.

TPL 003: System Performance Following Loss of Two or More BES Elements

In addition to the transmission facilities that would overload for category B contingencies, additional transmission lines may overload for category C contingencies.

For these overloads, which are listed in Appendix A, the NERC reliability standards allow for controlled load curtailment. The ISO recommends developing operating procedures or SPS to drop load or generation for these contingencies.

The list of overloaded facilities and proposed mitigations is shown in Appendix A.

Other Projects

San Diego Area Dynamic Reactive Support

SDG&E submitted four projects to install synchronous condensers at Mission, Penasquitos, Sycamore and Talega 230 kV Substations.

Each of these projects proposed to install +/- 240 MVar of dynamic reactive support at the respective substations to address the anticipated need for reactive sources and sinks in the area. The reliability assessment performed by the ISO did not identify any issues that can be mitigated by these upgrades. These upgrades can solve an expected issue of reactive source-sink availability if and when the Encina plant retires. But it is possible that Encina will be re-powered and more internal San Diego generation will materialize. Any additional internal generation in the area will affect the need for reactive support. Hence, the ISO has identified these projects as potential solutions for voltage stability. The need will be evaluated in future planning cycles as the generation retirement issue gathers some clarity.

Imperial Valley Flow Control Device

SDG&E submitted a project to install a flow control device at Imperial Valley Substation – Imperial Valley Flow Control Device. This project can control the amount of loop-flow through the Comisión Federal de Electricidad (CFE) system and support renewable flow into SDG&E system from the East. Reducing the loop-flow can affect the cross-tripping SPS at Imperial Valley. Although the reliability assessment did not exhibit a need for a phase shifter, the ISO recommends further evaluation in a future planning cycle.

2.8.5 Key Conclusions

The ISO initially proposed a total of 19 upgrades and mitigations (see Appendix A) to address identified reliability concerns.

In response to the ISO study results and proposed solutions:

- Twenty-one reliability project submissions were received through the 2011 Request Window. Out of the projects, several were alternatives for solving the same problems.

The ISO determined that the following 5 projects are needed:

- TL633, Bernardo-Rancho Carmel 69 kV: Reconductor;
- reconductor TL631, El Cajon-Los Coches;
- TL695B, Talega Tap-Japanese Mesa Reconductor;
- replace Talega 138/69 kV Bank 50; and
- TL642B, Sweetwater-Montgomery Tap-Terminal Equipment.

The following 6 projects submitted in the Request Window are determined not to be needed:

- TL6912, Pendleton-San Luis Rey Reconductor;
- New TL69XX San Luis Rey-Monserate 69 kV Line;
- TL69XX, Melrose-Monserate;
- TL694A Morro Hill Tap-Melrose Reconductor;
- TL680B-Melrose-Melrose Tap: Reconductor; and
- TL13820, Sycamore-Chicarita Reconductor.

The following 10 projects will be evaluated in future planning cycles:

- Imperial Valley Flow Control Device;
- a new line, TL6942, New Line from Sycamore Canyon-Miramar;
- substation expansion, Expand Los Coches Substation to 230 kV;
- TL690C, Oceanside Tap-Stuart Tap Reconductor;
- TL662, Penasquitos-Torrey Pines;
- reconductor TL649A, Otay-Otay Lake Tap;
- install Synchronous Condensers at Mission 230 kV Substation;
- install Synchronous Condensers at Penasquitos 230 kV Substation;
- install Synchronous Condensers at Sycamore 230 kV Substation; and
- install Synchronous Condensers at Talega 230 kV Substation.

Chapter 3

Special Reliability Studies and Results

3.1 Overview

The special studies discussed in this chapter include ones of transmission projects identified in the ISO tariff that have not been addressed elsewhere in the transmission plan. These comprise projects that may be needed to maintain long-term congestion revenue rights feasibility, local capacity technical analysis and location constrained resource interconnection facilities (LCRIFs). In addition, the ISO also performed reliability assessments under various load and resource scenarios that may result from the state's other environmental policies. This includes the State Water Resources Control Board's (SWRCB) policy on once-through cooling (OTC) power plants and Assembly Bill 1318. AB 1318 requires coordination between various state energy agencies and the ISO under the leadership of the California Air Resources Board (CARB) to assess potential emission offset needs for fossil power plant development to maintain electric reliability in the South Coast Air Basin's jurisdiction.

3.2 Reliability Requirement for Resource Adequacy

Sections 3.2.1 and 3.2.2 summarize the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under Article 5 of the ISO tariff. The local capacity technical analysis addressed the minimum local capacity requirements (LCR) on the ISO grid. The Resource Adequacy Import Allocation study established the maximum resource adequacy import capability to be used in 2012.

3.2.1 Local Capacity Requirements

The ISO conducted short and long-term local capacity technical (LCT) analysis studies in 2011. A short-term LCT analysis was conducted for the 2012 system configuration to determine the minimum local capacity requirements for the 2012 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria for the local capacity areas as required by the ISO tariff section 40.3. This study was conducted January-April through a transparent stakeholder process, with a final report published on April 29, 2011. A long-term LCT analysis was also performed to identify local capacity needs in the 2016 period, and a report was published at the end of January 2012. The long-term analysis was performed to provide participants in the transmission planning process with future trends in LCR needs for up to five-years. This section summarizes study results from both the short-term and long-term LCR need.

As shown in the LCT Report and indicated in the LCT Manual, 10 load pockets are located throughout the ISO-controlled grid as shown in Table 3.2-1 and illustrated in Figure 3.2-1 below.

Table 3.2-1: List of LCR areas and the corresponding PTO service territories within the ISO BA area

No	LCR Area	PTO Service Territory
1	Humboldt	PG&E
2	North Coast and North Bay	
3	Sierra	
4	Greater Bay Area	
5	Stockton	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	San Diego	SDG&E

Figure 3.2-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configuration. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 200 MW. In contrast, the requirements of the Los Angeles Basin are approximately 10,000 MW. The short- and long-term LCR needs from this year's studies are shown in Table 3.2-2.

Table 3.2-2: Local capacity areas and requirements for 2012 and 2016

LCR Area	Existing LCR Capacity Need (MW) 2012	2016
Humboldt	190	198
North Coast/North Bay	613	901
Sierra	1685	1033
Stockton	389	326
Greater Bay Area	4278	4565
Greater Fresno	1899	2166
Kern	297	682
Los Angeles Basin	10865	10380
Big Creek/Ventura	3093	2348
Greater San Diego/Imperial Valley	2849	2982
Total	26158	25581

For more information about the LCR criteria, methodology and assumptions please refer to the ISO website at: http://www.caiso.com/18a3/18a3d40d1d990.html.

For more information about the 2012 LCT study results, please refer to the report posted on the ISO website at: http://www.caiso.com/Documents/Local%20capacity%20technical%20analysis/Final2012LCTStudyReportApr29_2011.pdf.

For more information about the 2016 LCT study results, please refer to the report posted on the ISO website at: http://www.caiso.com/Documents/Final2016LCTStudyReportJan30_2012.pdf.

3.2.2 Resource Adequacy Import Capability

In accordance with ISO tariff section 40.4.6.2.1, the ISO has established the maximum RA import capability to be used in year 2012. This data can be found at: http://www.caiso.com/Documents/2012%20Import%20allocations/ISOMaximumResourceAdequacyImportCapability_Year2012.pdf. For more information regarding the entire 2012 import allocation process, please see this link: http://www.caiso.com/1c44/1c44b2dd750.html.

In accordance with Reliability Requirements BPM section 5.1.3.5.1, the ISO has established the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 1,500 MW in year 2021 to accommodate renewable resources development in this area. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The ISO also confirms that all other import branch groups or sum of branch groups have enough MIC to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2021.

The 10-year increase in MIC from the IID area is dependent on transmission upgrades in both the ISO and IID areas as well as new resource development within the IID and ISO systems. Table 3.2-3 shows the ISO estimates of how the increase in MIC will be achieved. The allocation of the MIC increases between the IID-SCE_BG and the IID-SDGE_BG can vary as long as the total does not exceed the amounts shown, and is limited by the maximum operating transfer capability (OTC) for each branch group in the appropriate year.

Table 3.2-3: ISO estimate of total policy driven MIC

<table>
<tr><th></th><th>2012</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th></tr>
<tr><td>IID-SCE_BG</td><td>517</td><td>517</td><td rowspan="2">1000</td><td rowspan="2">1000</td><td rowspan="2">1000</td><td rowspan="2">1000</td><td rowspan="2">1500</td><td rowspan="2">1500</td><td rowspan="2">1500</td><td rowspan="2">1500</td></tr>
<tr><td>IID-SDGE_BG</td><td>0</td><td>0</td></tr>
</table>

The 2014 increase is dependent on the in-service dates for:

a) Path 42 upgrades to both the SCE as well as the IID system;

b) completion of the entire scope of the West of Devers interim upgrades (reactors and SCE and IID area SPS).

The 2018 increase is dependent on the in-service date for the West of Devers reconductoring project.

The future outlook for all remaining branch groups can be accessed at:

http://www.caiso.com/Documents/Advisory%20estimates%20of%20future%20resource%20adequacy%20import%20capability.

3.3 Once-Through Cooling Generation Retirement Studies

3.3.1 Background, Methodology and Assumptions

Approximately 30 percent of California's in-state generating capacity (gas and nuclear power) uses coastal and estuarine water for once-through cooling. On May 4, 2010, the State Water Resources Control Board adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy establishes uniform, technology-based standards to implement federal Clean Water Act section 316(b), which requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. It required the owner or operator of an existing non-nuclear fossil fuel power plant using once-through cooling to submit an implementation plan to the SWRCB on April 1, 2011. In most cases, the implementation plans selected an alternative that would achieve compliance by a date specified for each facility identified in the policy.

Nuclear units may also seek to establish site-specific requirements for best technology available. The policy directs Pacific Gas and Electric Company and Southern California Edison to conduct special studies to investigate alternatives for the nuclear units to meet the requirements. The studies are to include the costs for these alternatives. The SWRCB requires that the report on these special studies be submitted by October 1, 2013.

The ISO anticipates that the SWRCB policy will force the majority of gas-fired generating units using once-through cooling either to come off-line to retrofit or repower using alternative cooling technologies, or retire. The ISO needs to assess the reliability impacts to the ISO grid that may result from these actions.

Another consideration arising from the SWRCB policy is the connection between generating units using once-through cooling and renewable integration. Many of the units using once-through cooling technology have characteristics that would support renewable integration. Replacement infrastructure will need to retain or improve these capabilities (whether by the repowered plants or replacement capacity). Additionally, because of the contribution of these units to system operations, it will be essential to plan any retrofit or repowering efforts or retirements in a manner consistent with the operational requirements created by an expanding portfolio of renewables. Such requirements may be higher in some years than in others, because of the mix of renewables on the system. The process of complying with the once-through cooling policy is thus another factor to consider in preparing the power system for higher levels of renewable resources.

For purposes of the 2011/2012 transmission planning process, the ISO continued its collaborative study efforts with various state agencies and stakeholders. In 2010, with assistance from the CPUC and CEC, the ISO posted a load and resource analysis tool. The ISO uses the tool to screen and identify potential time frames in which local resources are less than the projected resources needed to maintain local reliability under a range of resource scenarios. The ISO also performed technical evaluations using power flow and transient stability programs for various RPS scenarios (i.e., trajectory, environmentally constrained, ISO base case, cost-constrained and time-constrained) to determine long-term (2021) local capacity requirements for areas that currently have OTC generating units. These areas are the Greater Bay Area, Big Creek/Ventura, the Los Angeles Basin and San Diego. The following is an outline of the studies for this planning cycle:

3.3.1.1 Long-Term LCR and Zonal Assessments

The ISO performs a reliability assessment (i.e., power flow and stability analyses) using the 2021 RPS study cases as seed cases to develop long-term LCR and zonal study cases.

- Using 2021 LCR cases prepared for the Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego local areas, the ISO performed reliability assessments. The assessments determined the range of generation requirements — including OTC generation — that are needed to maintain applicable LCR reliability criteria for these areas under four different RPS portfolios (i.e., trajectory, environmentally constrained, ISO base case, and time-constrained).
- The ISO also performed a reliability assessment for the zonal area, particularly for the South of Path 26 area. This assessment identified reliability concerns, particularly with a potential minimum level of OTC generation modeled in the studies. If reliability concerns were identified in the zonal area, potential mitigation measures were identified, either with generation or transmission solutions.

3.3.1.2 Screening Evaluation Using Load and Resources Tool

- ISO performed a load and resource evaluation using the tool to determine which years would have a deficiency of resources for local capacity areas as well as zonal areas (i.e., NP 26 and SP 26) or ISO balancing authority. For this effort, the ISO evaluated the unavailability of affected generating units based on the following: the compliance years set forth in the SWRCB policy; or the years generator owners identify in their implementation plans to come off-line to take steps to comply with the policy.
- In addition, the ISO also evaluated resource adequacy in the zonal or balancing authority using inputs from the results of the long-term LCR assessment (Step 1 above) to identify any resource concerns. This type of assessment is similar in concept to the annual summer assessment that the ISO performs.

3.3.1.3 Evaluation of Potential Reliability Mitigations

The following potential mitigation measures were evaluated on a high level in order to maintain local or zonal reliability:

- identifying generation need;
- identifying potential transmission mitigation measures; and
- identifying potential demand side management or other contracted resources such as combined heat and power.

3.3.2 Once Through Cooling Reliability Assessment – Study Results

In this section, the following assessment results are reported:

- Reliability assessment of the local capacity requirement (LCR) areas that have once-through cooling power plants — this includes the Greater Bay Area, Big Creek/Ventura, Los Angeles Basin and San Diego. The purpose of this study is to identify whether there is a reliability need to run OTC plants, and if there is, what OTC generation level is needed.

- Transient stability assessment for on-peak and off-peak load conditions — for on-peak load conditions, the assessment was performed for the trajectory and environmentally constrained RPS portfolios. For the off-peak conditions, the assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation modeled, would still meet the WECC transient stability reliability criteria.

- Loads and resource assessment for zonal (NP26 and SP26) and ISO balancing authority — this assessment provides preliminary long-term evaluation of the adequacy of future generation to serve loads in the 2021 time frame under two load scenarios, 1-in-2 year and 1-in-10 year heat wave load conditions. This is similar to the ISO annual summer assessment, except that it looks ten years into the future, whereas the annual summer assessment evaluates the adequacy of resources for the next summer condition.

3.3.2.1 New Conventional Generation and Major Transmission Projects Assumed in the Studies

The starting power flow base cases were obtained from the power flow base cases for the four RPS portfolios: trajectory, environmentally constrained, ISO base case and time-constrained. These cases were then stressed further to include 1-in-10 heat wave load projection for the LCR areas under evaluation. Utilizing the same study process from the annual LCR studies, the following LCR areas that have OTC generation were modeled with 1-in-10 year heat wave load projections:[20]

- Greater Bay Area;
- Big Creek/Ventura Area; and
- Southern California Area (for studying LA Basin and San Diego areas).

Since the study base cases started with the RPS study cases, they have the same assumptions of the new conventional generation and major transmission projects. Please refer to the policy-driven write-up for details on these new conventional generation and major transmission project assumptions.

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[20] The 1-in-10 year heat wave load projections were obtained from the official CEC-adopted demand forecast, which is the 2009 CEC-adopted demand forecast. A review of the CEC's 2011 preliminary demand forecast indicates that the long-term forecast is actually similar to or higher than the 2009 adopted forecast for the high net load conditions.

3.3.2.2 Summary of Study Results

In this section, the following study results are summarized:

- LCR assessment for the four local areas having once-through cooling generation: Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego;
- transient stability assessment for trajectory and environmentally constrained RPS portfolios at peak load conditions and for environmentally constrained portfolio at off-peak load conditions; and
- preliminary supply and demand outlook assessment in 2021 for trajectory and time-constrained RPS portfolios for 1-in-10 year and 1-in-2 year heat wave load projections.

LCR Study Results

Detailed LCR assessments are discussed further in the following sections. Table 3.3-1 provides a summary of generation requirements in the main LCR areas where OTC generating units are currently located. Both distributed generation and non-distributed generation (i.e., centralized generating stations) are listed. The total generation requirements include both generation categories. If distributed generation does not materialize as indicated, its projected capacity needs to be replaced with other generation with equivalent capacity level.

Table 3.3-1: Summary of long-term (2021) LCR study results

<table>
<tr><th rowspan="2">LCR Area</th><th colspan="4">Local Capacity Requirements (MW)</th><th colspan="4">New Generation Need? #
If Yes, Range of New Generation Need (MW)</th></tr>
<tr><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th></tr>
<tr><td>Greater Bay Area</td><td>5,773</td><td>4,728</td><td>5,778</td><td>6,572</td><td colspan="4">No</td></tr>
<tr><td rowspan="2">Big Creek/Ventura (BC/V) Area</td><td rowspan="2">2,371</td><td rowspan="2">2,604</td><td rowspan="2">2,438</td><td rowspan="2">2,653</td><td colspan="4">Yes (for Moorpark, a sub-area of the Big Creek/Ventura LCR area)</td></tr>
<tr><td>430</td><td>430</td><td>430</td><td>430</td></tr>
<tr><td>LA Basin (this area includes sub-area below)</td><td>13,300</td><td>12,567</td><td>12,930</td><td>13,364</td><td rowspan="2">2,370 – 3,741</td><td rowspan="2">1,870 – 2,884</td><td rowspan="2">2,424 – 3,834</td><td rowspan="2">2,460 – 3,896</td></tr>
<tr><td>Western LA Basin (sub-Area of the larger LA Basin)</td><td>7,797</td><td>7,564</td><td>7,517</td><td>7,397</td></tr>
<tr><td>San Diego / Imperial Valley (this area includes sub-area below)</td><td>3,291</td><td>3,104</td><td>2,968</td><td>3,272</td><td colspan="4">Yes (*Lower values correspond to new generation need # when including SDG&E-proposed generation for LTPP)</td></tr>
<tr><td>San Diego **</td><td>2,883</td><td>2,854</td><td>2,864</td><td>2,856</td><td>531* - 950</td><td>231*- 650</td><td>231*- 650</td><td>421*- 840</td></tr>
</table>

Notes: *Lower values correspond to new generation need when including SDG&E-proposed generation for Long Term Power Plan (LTPP) process

** Load curtailment of 366 MW is included for G-1/N-2 contingency (Otay Mesa / Sunrise + SWPL outage)

New generation need (i.e., repowering) assuming existing OTC generation is to retire

Transient Stability Assessments

A key concern is whether future generation portfolios that include significant penetration of renewable generation, coupled with potential shutdown or retirement of some OTC generating units would contribute to the deterioration of inertia needed to maintain transient stability under critical contingencies. To address this concern, the ISO performed dynamic stability assessments for the trajectory study case for the peak load and for the environmentally constrained study cases for the peak load and off-peak load conditions. A minimum amount of OTC generation was modeled for these study cases. Environmentally constrained study cases represent stressed cases because of the presence of significant amount of distributed generation (i.e., photovoltaic generation) and less conventional generation than other portfolios.

The following tables provide summaries of transient stability study results. Critical contingencies in the WECC system were performed to see whether system performance met WECC transient stability reliability criteria (refer to table 3.3-2).

Table 3.3-2: Summary of transient stability studies for peak load conditions

Contingencies	Trajectory Portfolio Case		Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-2	√	√	√	√
Diablo – Midway 500kV N-2	√	√	√	√
IPPDC Bi-polar	√	√	√	√
Los Banos North 500kV N-2	√	√	√	√
Los Banos South 500kV N-2	√	√	√	√
Lugo South 500kV N-2	√	√	√	√
Lugo – Vincent 500kV N-2	√	√	√	√
Midway-Vincent 500kV N-2	√	√	√	√
PDCI Bipolar	√	√	√	√
Palo Verde G-2	√	√	√	√
SONGS G-2	√	√	√	√
Table Mtn.-Tesla+VacaDixon-Tesla 500kV N-2	√	√	√	√
Sunrise + SWPL N-2	√	√	√	√
Vincent – Antelope 500kV N-2	√	√	√	Does not meet for Correct 66kV substation

Table 3.3-3: Summary of transient stability study results for off-peak load conditions

Contingencies	Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-1	√	√
Diablo – Midway 500kV N-2	√	√
IPPDC Bi-polar	√	√
Tesla – Metcalf 500kV line	√	√
Vincent – Antelope 500kV N-2	√	√
Lugo South 500kV N-2	√	√
Lugo – Vincent 500kV N-2	√	√
Midway-Vincent 500kV N-2	√	√
PDCI Bipolar	√	√
Palo Verde G-2	√	√
SONGS G-1	√	√
Vincent – Mesa 230kV N-2	√	√
Sunrise + SWPL N-2	√	√

Based on the results above, the studied portfolios with minimum OTC generation met WECC transient stability reliability criteria. The environmentally constrained portfolio for the peak load conditions did result in a frequency excursion beyond the WECC minimum frequency limit (i.e., 59.0 Hz) for one sub-transmission load substation in the SCE service territory. However, the frequency excursion occurred for a radial load system and did not affect network facilities.

Estimated Summer 2021 Supply and Demand Outlook

To address concerns as to whether generation supplies are adequate for zonal areas (i.e., NP26 or SP26) or ISO balancing authority in the long-term (i.e., 2021 time frame), an estimated supply and demand assessment was performed for two load conditions: 1-in-2 and 1-in-10 heat wave load projections. This approach is similar to the ISO annual summer assessment in which a supply and demand outlook is provided for the next summer. The difference is that this provides a long-term outlook compared to the short-term outlook provided under the annual summer assessment. In addition, the assessment reported here is based on import assumptions using projected 2021 Maximum Import Capability (MIC). The 2021 long-term assessment is considered informational only because the official long-term supply and demand outlook is typically carried out under the CPUC Long-Term Procurement Plan (LTPP) process with significant participation from various stakeholders. The ISO assessment is intended to be used for informational purposes to provide an indication of potential trends or areas of concerns for stakeholders to investigate further in future regulatory or planning studies.

The following tables are summaries for the summer 2021 supply and demand outlook for the trajectory portfolio for the 1-in-2 and 1-in-10 heat wave load projections with projected 2021 MIC import assumption. From these assessments, it appears that there is no resource deficiency identified for 1-in-2 heat wave load projections. For 1-in-10 heat wave load projections, it appears that the operating reserve margins for ISO system and SP26 zonal areas are thin at about 3%.

Table 3.3-4: Estimated summer 2021 supply and demand outlook (1-in-10 load conditions) — trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio

1-in-10 Demand and 1-in-10 Generation & Transmission Outage Scenarios

Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)			
Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-10 Generation & Transmission)	(6,844)	(3,872)	(3,616)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	60,093	34,776	28,424
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-10 summer temperature)	60,773	35,507	26,760
Surplus/(Deficiency) (MW)	1,616	990	2,239
Operating Reserve Margin	2.7%	2.8%	8.4%

Table 3.3-5: Estimated summer 2021 supply and demand outlook (1-in-2 load conditions) – trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio

1-in-2 Demand and 1-in-2 Generation & Transmission Outage Scenarios

Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)			
Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-2 Generation & Transmission)	(4,698)	(2,033)	(2,677)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	62,239	36,615	29,363
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-2 summer temperature)	56,029	32,467	24,940
Surplus/(Deficiency) (MW)	8,507	5,869	4,999
Operating Reserve Margin	15.2%	18.1%	20.0%

Conclusions

To evaluate the reliability impacts to ISO controlled grid due to implementation of the SWRCB's Policy on Once through Cooling Plants (the Policy), various assessments were performed for local reliability areas, zonal areas and ISO Balancing Authority Area (BAA). Once-through cooling generation need was determined for the local reliability areas and served as foundational OTC generation need before zonal and ISO BAA assessments.

1. Local area assessments:

Reliability assessments using LCR methodology were performed for the local reliability areas that have OTC generation to determine grid reliability impacts to these areas and subsequently the ranges of once-through cooling generation needed for maintaining local reliability. The local areas that currently have OTC generation that are subject to the SWRCB's Policy include the Greater Bay Area, Big Creek/Ventura, Los Angeles Basin and San Diego areas. The generation owners of the OTC plants in these areas have submitted their implementation plans to the SWRCB, but because these plans are still uncertain subject to whether they will receive long-term Power Purchase Agreements (PPAs) or whether these plans will receive permit for construction from the CEC, the ISO provided the results of OTC generation need in ranges for the LCR areas. The low level of the range corresponds to the generation located in more effective locations, and vice versa for the high level need. If a sub-area has only one OTC generation power plant, then the reporting would be done without the ranges (i.e., Moorpark sub-area of the Big Creek/Ventura area). If the OTC generation was considered alongside an LSE-proposed generation development plan, the ranges include the OTC generation need with and without the LSE's new generation plan (i.e., San Diego area).

The following table summarizes the ranges of OTC generation need for studied LCR areas. The generation at the existing OTC generation locations can comply with the SWRCB's Policy by either repowering or replacement with Best Technology Available (BTA) cooling technology (i.e., closed cycle wet cooling). The other option, which is yet to be considered and approved by the SWRCB, is implementing Track 2 option, which would involve reducing impacts to aquatic life by other means.

Table 3.3-6 – Summary of OTC Generation Need

LCR Area	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)	Notes
Greater Bay Area	0	0	0	0	No OTC generation need identified
Big Creek/Ventura (Moorpark Sub-area)	430	430	430	430	
West LA Basin / LA Basin	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896	W. LA Basin is part of larger LA Basin
San Diego	531* - 950	231*-650	231*-650	421*-840	*The lower range corresponds to the use of SDG&E-proposed generation included in its LTPP to the CPUC

2. Zonal Area and ISO BAA Resource Assessment

After evaluation of the local areas, the ISO performed loads and resource assessments for zonal areas (i.e., NP26, SP26) and ISO BAA under one-in-two and one-in-ten year heat wave load conditions. The objective of these assessments is to identify any resource concerns for zonal areas and ISO BAA, similar to the ISO annual summer assessment. The ISO included in these resource assessments the needed OTC generation capacity, identified in the individual LCR assessments. In these assessments, only the lower ranges of OTC generation were included. If the OTC generation was to be repowered at less effective locations, then higher ranges of OTC generation, as identified in the above table, would need to be updated for the zonal and ISO BAA loads and resource assessments. For the OTC generation that was not identified as needed for the LCR areas, it was included as potential retirement generation (or unavailable generation) due to uncertainty in obtaining long-term PPA from the LSEs. Four RPS portfolios were evaluated, but the resource concerns for SP26 were identified for the trajectory and time-constrained portfolios. Based on the results in Tables 3.3-4 and 3.3-5, the following potential resource concerns for the ISO BAA and SP26 for the trajectory RPS portfolio were identified:

- For 1-in-10 heat wave load projections, it appears that the operating reserve margins for ISO system and SP26 zonal areas are thin at about 3%, which is a threshold value in which load curtailment may be needed if the margins are declining further.

3. Transient Stability Assessment

Transient stability studies were performed and the following were found:

- System response met WECC reliability criteria for trajectory portfolio under peak load conditions for critical contingencies; for environmentally constrained portfolio, a radial load bus in SCE was found to be outside of WECC frequency limit criteria. However, this is still acceptable as it does not cause transient stability impact to other areas other than this radial facility.
- System response met WECC reliability criteria for environmentally constrained portfolio under off-peak load conditions for critical contingencies.

The studies described here were intended to identify capacity needs for meeting applicable reliability planning purposes. For operational needs, such as ramping and regulation, the reader is advised to follow the ISO renewable integration study work for those requirements.

3.3.2.3 Detailed LCR Studies

The starting power flow cases originated from the policy-driven cases for the four RPS portfolios: trajectory, environmentally constrained, ISO base case and time-constrained. These power flow cases were then adjusted further to have 1-in-10 year heat wave loads for Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego.[21] Since LA Basin and San Diego areas peak almost at the same time, these two areas share common study cases with 1-in-10 heat wave load projection.

Because the LCR power flow cases originated from the policy-driven power flow cases, they have the same major new transmission and conventional generation projects.

The following once-through cooling generating units were assumed to be in service in the starting LCR study cases:

- Diablo Canyon and San Onofre Nuclear Generating Station: The SWRCB has a separate but parallel process for review of the nuclear power plant compliance with the OTC policy. This process, overseen by the SWRCB's Review Committee, requires special studies to be performed by an independent third party to evaluate various compliance options and associated costs. The special studies report is required to be submitted to the SWRCB by October 1, 2013.
- Moss Landing Units 1 and 2: These are relatively new combined cycled power plants that came on line in 2002. Similar to other new combined cycled projects, these power plants are efficient in running generation. When these power plants went through the CEC environmental review process, other cooling technology options were evaluated, but they were rejected because they were deemed environmentally infeasible.[22] The CEC approved the environmental permit for Dynegy to proceed with construction of the power plants. As part of its implementation plan submittal to the SWRCB on April 1, 2011, Dynegy claimed that it employs best technology available for cooling of the plant, which is yet to be resolved and agreed to by the SWRCB.

3.3.2.3.1 LCR Study Results — Greater Bay Area

To determine whether OTC generation is needed, and if it is, what level would be required for the Greater Bay Area in 2021, an LCR analysis was performed for the four RPS portfolios. The following area and sub-areas were examined for generation requirements:

[21] The ISO uses the latest CEC-adopted load forecast for LCR studies. The latest Commission-adopted forecast is obtained from the 2009 adopted demand forecast. The CEC's 2011 demand forecast is preliminary and is not yet adopted by the Commission. For long-term forecast (i.e., ten years out), based on the CEC preliminary forecast for each respective utilities, the new forecast is either similar or higher than the 2009 adopted forecast for 1-in-2 heat wave load projection (http://www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf)

[22] See Table 1 in the following document: (http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/moss_landing/docs/ml_ip2011attch_c.pdf)

- San Francisco sub-area;
- San Jose sub-area;
- Peninsula sub-area;
- Mission sub-area;
- East Bay sub-area;
- Diablo sub-area;
- DeAnza sub-area; and
- Overall GBA area.

None of the areas was determined to have any need for OTC generation.

Area Definition for Greater Bay Area

The transmission tie lines into the Greater Bay Area are as follows:

1. Lakeville-Sobrante 230 kV line;
2. Ignacio-Sobrante 230 kV line;
3. Parkway-Moraga 230 kV line;
4. Bahia-Moraga 230 kV line;
5. Lambie SW Sta-Vaca Dixon 230 kV line;
6. Peabody-Birds Landing SW Sta 230 kV line;
7. Tesla-Kelso 230 kV line;
8. Tesla-Delta Switching Yard 230 kV line;
9. Tesla-Pittsburg #1 230 kV line;
10. Tesla-Pittsburg #2 230 kV line;
11. Tesla-Newark #1 230 kV line;
12. Tesla-Newark #2 230 kV line;
13. Tesla-Ravenswood 230 kV line;
14. Tesla-Metcalf 500 kV line;
15. Moss Landing-Metcalf 500 kV line;
16. Moss Landing-Metcalf #1 230 kV line;
17. Moss Landing-Metcalf #2 230 kV line;
18. Oakdale TID-Newark #1 115 kV line; and
19. Oakdale TID-Newark #2 115 kV line.

The substations that delineate the Greater Bay Area are as follows:

1. Lakeville is out, Sobrante is in;
2. Ignacio is out, Crocket and Sobrante are in;
3. Parkway is out, Moraga is in;
4. Bahia is out, Moraga is in;
5. Lambie SW Sta is in, Vaca Dixon is out;
6. Peabody is out, Birds Landing SW Sta is in;
7. Tesla and USWP Ralph are out, Kelso is in;
8. Tesla and Altmont Midway are out, Delta Switching Yard is in;
9. Tesla and Tres Vaqueros are out, Pittsburg is in;
10. Tesla and Flowind are out, Pittsburg is in;
11. Tesla is out, Newark is in;
12. Tesla is out, Newark and Patterson Pass are in;
13. Tesla is out, Ravenswood is in;
14. Tesla is out, Metcalf is in;
15. Moss Landing is out, Metcalf is in; and
16. Oakdale TID is out, Newark is in;

Total 2021 bus load within the defined area is 10,700 MW. Each RPS portfolio has different line losses. The following Table 3.3-7 is a Greater Bay Area load and resource summary for all four portfolios.

Table 3.3-7: Loads and resource summary in GBA

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	10,949	10,920	10,951	10,938
Generation				
Existing Non NQC (2012)	5,285			
Existing OTC Capacity (2012)	1,303			
New Generation	2,308			
Distributed Generation	43	892	101	269

Critical Contingency Analysis Summary

Sub Areas

Each sub-area was evaluated for its own LCR, and the corresponding requirements were incorporated into the overall Greater Bay Area.

Since no OTC generation is needed in the sub-areas, the OTC need was then evaluated for the overall Greater Bay Area.

Overall Greater Bay Area

The most critical contingency for the overall Greater Bay Area is common for all four RPS scenarios, namely the environmental, base, trajectory and time-constrained portfolios. The outage is a combination of N-1/G-1 with Tesla-Metcalf 500 kV line and Delta Energy Center. The limiting element is a voltage collapse condition.

This common constraint establishes the following LCR for the four portfolios:

Table 3.3-8: LCR for the four portfolios in the Greater Bay Area

Portfolio	LCR (MW)
Trajectory	5,773
Environmental	4,728
Base	5,778
Time	6,572

LCR Summary by Portfolios

The following table summarizes the OTC and LCR requirements for each portfolio. The table also lists the worst contingencies and limiting elements.

Table 3.3-9: Trajectory portfolio — LCR and OTC requirements in the Greater Bay Area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
ISO Base case	GBA	5,677	101	5,778	No	Voltage Collapse	Tesla-Metcalf 500kV Line + DEC
Environmentally constrained		3,836	892	4,728	No		
Time-constrained		6,303	269	6,572	No		
Trajectory		5,730	43	5,773	No		

Conclusions

It was determined that there is no need for OTC generation across all four RPS portfolios. Table 3.3-10 below is a summary of LCR and OTC generation requirements for the overall Greater Bay Area.

Table 3.3-10: Summary of LCR and OTC requirements in Greater Bay Area

LCR Area	Trajectory (MW)	Environmentally constrained (MW)	ISO Base Case (MW)	Time-constrained (MW)
Overall GBA	5,773	4,728	5,778	6,572
OTC Gen. Need	0	0	0	0

3.3.2.3.2 LCR Study Results — LA Basin Area

To determine the level of OTC generation requirements for the LA Basin in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall LA Basin;
- Western LA Basin;
- Ellis sub-area; and
- El Nido sub-area.

The Western LA Basin and Ellis sub-area drive the need for OTC units. The Ellis sub-area needs these units to mitigate a voltage collapse issue. The Western LA area needs these units to mitigate an overloading issue. The overall LA Basin generation requirements also incorporate the need for this OTC generation.

Area Definition for Overall LA Basin

The transmission tie lines into the LA Basin are:

1. San Onofre-San Luis Rey #1, #2, and #3 230 kV lines;
2. San Onofre-Talega 230 kV line;
3. San Onofre-Capistrano 230 kV line;
4. Lugo-Mira Loma #2 & #3 500 kV lines;
5. Lugo-Rancho Vista #1 500 kV line;
6. Sylmar-Eagle Rock 230 kV line;
7. Sylmar-Gould 230 kV line;
8. Vincent-Mesa Cal #1 and #2 230 kV lines;
9. Vincent-Rio Hondo #1 and #2 230 kV lines;
10. Devers-Red Bluff #1 and #2 500 kV lines;

11. Mirage-Coachella valley 230 kV line;
12. Mirage-Ramon 230 kV line; and
13. Mirage-Julian Hinds 230 kV line.

These sub-stations form the boundary surrounding the LA Basin:

1. San Onofre is in, San Luis Rey is out;
2. San Onofre is in, Talega is out;
3. San Onofre is in, Capistrano is out;
4. Mira Loma is in, Lugo is out;
5. Rancho Vista is in, Lugo is out;
6. Eagle Rock is in, Sylmar is out;
7. Gould is in, Sylmar is out;
8. Mesa Cal is in, Vincent is out;
9. Rio Hondo is in, Vincent is out;
10. Devers is in, Red Bluff is out;
11. Mirage is in, Coachella Valley is out;
12. Mirage is in, Ramon is out; and
13. Mirage is in, Julian Hinds is out.

The total 2021 substation load (bus bar level) within the defined area is 22,686 MW. Each portfolio has different losses. The following table is the LA Basin load and resource summary for all four portfolios.

Table 3.3-11: Loads and resource summary in LA Basin area

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	22,867	22,838	22,872	22,862
Generation				
Existing NQC (2012)	12,083			
Existing OTC Capacity (2012)	5,166			
Distributed Generation	339	1,519	271	687

Critical Contingency Analysis Summary

Overall LA Basin

The most critical contingency for the overall LA Basin for all four portfolios is an N-1/T-1 contingency of Chino-Mira Loma East #3 500 kV line and Mira Loma West 500/230 kV bank #2. The limiting element is Mira Loma West 500/230 kV bank #1 (24-hour rating). This constraint establishes the LCR numbers for the four RPS portfolios in Table 3.3-14 below:

Table 3.3-12: LCR for overall LA Basin with contingency affecting Mira Loam AA transformers

Portfolio	LCR (MW)
Trajectory	13,300
Environmental	12,567
Base	12,930
Time	13,364

Mira Loma West 500/230 kV bank #1 has a 1-hour emergency rating. This emergency rating can be utilized by assuming up to 600 MW of either load curtailment or load transfer within 1 hour. If this mitigation is feasible, the next worst contingency for the overall LA Basin area is the outage of Sylmar S-Gould 230 kV line and Lugo-Victorville 500 kV line. The limiting element is Eagle Rock-Sylmar S 230 kV line. This constraint establishes LCR numbers for the four RPS portfolios as noted in the table below:

Table 3.3-13: LCR for overall LA Basin with contingency affecting Eagle Rock – Sylmar 230kV line

Portfolio	LCR (MW)
Trajectory	10,743
Environmental	11,246
Base	11,010
Time	12,165

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on the Eagle Rock-Sylmar 230 kV line constraint for the overall LA Basin.

Table 3.3-14: Units with at least 5 percent effectiveness on Eagle Rock-Sylmar 230 kV line constraint for overall LA Basin

Generator	Eff. Factor (%)
PASADNA1 13.8 #1	24
PASADNA2 13.8 #1	24
BRODWYSC 13.8 #1	24
MALBRG3G 13.8 #S3	15
MALBRG2G 13.8 #C2	15
MALBRG1G 13.8 #C1	15
CHEVGEN1 13.8 #1	13
CHEVGEN2 13.8 #2	13
MOBGEN1 13.8 #1	13
MOBGEN2 13.8 #1	13
LA FRESA 66.0 #10	13
NRG ELS7 18.0 #7	13
NRG ELG5 18.0 #5	13
NRG ELG6 18.0 #6	13
ARCO 5G 13.8 #5	12
ARCO 1G 13.8 #1	12
ARCO 2G 13.8 #2	12
ARCO 3G 13.8 #3	12
ARCO 4G 13.8 #4	12
ARCO 6G 13.8 #6	12
LBEACH34 13.8 #3	12
LBEACH34 13.8 #4	12
LBEACH12 13.8 #2	12
LBEACH12 13.8 #1	12
HARBOR G 13.8 #1	12
HARBOR G 13.8 #HP	12
CARBGEN1 13.8 #1	12
HINSON 66.0 #1	12
THUMSGEN 13.8 #1	12
CARBGEN2 13.8 #1	12
HARBOR 230.0 #F1	12
BRIGEN 13.8 #1	11
CTRPKGEN 13.8 #1	11
SIGGEN 13.8 #D1	11
ALMITOSW 66.0 #D3	10
ALAMT1 G 18.0 #1	9
ALAMT2 G 18.0 #2	9
ALAMT3 G 18.0 #3	9
HILLGEN 13.8 #D1	9
EME WCG1 13.8 #1	9

Generator	Eff. Factor (%)
EME WCG3 13.8 #1	9
EME WCG4 13.8 #1	9
EME WCG5 13.8 #1	9
EME WCG2 13.8 #1	9
ELLIS 66.0 #12	8
ELLIS 66.0 #11	8
HUNT1 G 13.8 #1	8
HUNT2 G 13.8 #2	8
BARRE 66.0 #11	8
BARRE 66.0 #10	8
BARPKGEN 13.8 #1	7
SANTIAGO 66.0 #1	7
COYGEN 13.8 #1	7
ANAHEIMG 13.8 #1	6
S.ONOFR2 22.0 #2	5
S.ONOFR3 22.0 #3	5
CHINO 66.0 #E1	5
DELGEN 13.8 #1	5
DELGEN 13.8 #1	5
SANIGEN 13.8 #D1	5
CIMGEN 13.8 #D1	5
SIMPSON 13.8 #D1	5

OTC Generation Needed

The need for OTC units in the overall LA Basin area is established specifically by the Western LA Basin and Ellis sub-areas. The following table establishes the lower range of OTC generation capacity is required across all four portfolios to mitigate respective reliability issues in areas. Lower ranges of OTC generation requirements correspond to OTC generation located in more effective locations. This OTC capacity is counted toward the total LCR need for the overall LA Basin. The OTC requirements for the overall LA Basin by portfolios are as noted in the following table:

Table 3.3-15: OTC requirements for overall LA Basin to mitigate reliability issues

Portfolio	Min OTC Need (MW)
Trajectory	2,370
Environmental	1,870
Base	2,424
Time	2,460

Western LA Basin Sub-Area

Area Definition for Western LA Basin

The transmission tie lines into the LA Basin are:

1. San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines
2. San Onofre - Talega #1 and #2 230 kV Lines
3. Serrano – Lewis #1 and #2 230 kV Lines
4. Serrano – Villa PK #1 and #2 230 kV Lines
5. Mira Loma – Walnut 230 kV Line
6. Mira Loma – Olinda 230 kV Line
7. Sylmar - Eagle Rock 230 kV Line
8. Sylmar - Gould 230 kV Line
9. Vincent - Mesa Cal #1 and #2 230 kV Line
10. Vincent - Rio Hondo #1 and #2 230 kV Line

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios as listed in the table below:

Table 3.3-16: LCR for Western LA Basin with identified contingencies

Portfolio	LCR (MW)
Trajectory	7,797
Environmental	7,584
Base	7,517
Time	7,397

Generation Effectiveness Factors

The following table shows generating units that have at least 5 percent effectiveness on Serrano-Villa Park 230 kV line constraint for Western LA Basin.

Table 3.3-17: Units with at least 5% effectiveness on Serrano-Villa Park 230 kV line constraint for Western LA Basin

Generator	Eff. Factor (%)
BARPKGEN 13.8 #1	32
BARRE 66.0 #11	32
BARRE 66.0 #10	32
ANAHEIMG 13.8 #1	32
ALAMT5 G 20.0 #5	24
ALAMT6 G 20.0 #6	24
ALAMT3 G 18.0 #3	24
ALAMT4 G 18.0 #4	24
ALAMT1 G 18.0 #1	23
ALAMT2 G 18.0 #2	23
ALMITOSW 66.0 #D3	23
ALMITOSW 66.0 #D2	23
ALMITOSW 66.0 #D1	23
ALAMT7 G 16.0 #R7	23
HUNT1 G 13.8 #1	23
HUNT2 G 13.8 #2	23
ORCOGEN 13.8 #1	23
ELLIS 66.0 #12	23
ELLIS 66.0 #11	23
ELLIS 66.0 #10	23
SANTIAGO 66.0 #1	17
COYGEN 13.8 #1	17
LITEHIPE 66.0 #10	16
BRIGEN 13.8 #1	16
LBEACH5G 13.8 #R5	16
LBEACH6G 13.8 #R6	16
LBEACH7G 13.8 #R7	16
HARBOR 230.0 #F1	16
HARBOR G 13.8 #1	15
HARBOR G 13.8 #HP	15
HINSON 66.0 #D8	15
HINSON 66.0 #D7	15
HINSON 66.0 #D6	15

Generator	Eff. Factor (%)
HINSON 66.0 #D4	15
HINSON 66.0 #D3	15
HINSON 66.0 #D1	15
CARBGEN1 13.8 #1	15
SERRFGEN 13.8 #D1	15
THUMSGEN 13.8 #1	15
CARBGEN2 13.8 #1	15
HINSON 66.0 #1	15
LBEACH12 13.8 #2	15
LBEACH34 13.8 #3	15
LBEACH8G 13.8 #R8	15
LBEACH9G 13.8 #R9	15
LBEACH34 13.8 #4	15
LBEACH12 13.8 #1	15
ARCO 1G 13.8 #1	15
ARCO 2G 13.8 #2	15
ARCO 3G 13.8 #3	15
ARCO 4G 13.8 #4	15
ARCO 5G 13.8 #5	15
ARCO 6G 13.8 #6	15
CENTER 66.0 #D1	15
SIGGEN 13.8 #D1	15
CTRPKGEN 13.8 #1	15
LCIENEGA 66.0 #D1	14
VENICE 13.8 #1	14
MOBGEN1 13.8 #1	14
OUTFALL1 13.8 #1	14
OUTFALL2 13.8 #1	14
PALOGEN 13.8 #D1	14
REDON1 G 13.8 #R1	14
REDON2 G 13.8 #R2	14
REDON3 G 13.8 #R3	14
REDON4 G 13.8 #R4	14
LA FRESA 66.0 #10	14

Generator	Eff. Factor (%)
LA FRESA 66.0 #D9	14
LA FRESA 66.0 #D8	14
LA FRESA 66.0 #D7	14
MOBGEN2 13.8 #1	14
CHEVGEN1 13.8 #1	14
CHEVGEN2 13.8 #2	14
ELSEG4 G 18.0 #4	14
ELSEG3 G 18.0 #3	14
REDON5 G 18.0 #5	14
REDON7 G 20.0 #7	14
REDON8 G 20.0 #8	14
REDON6 G 18.0 #6	14
NRG ELG5 18.0 #5	14
NRG ELG6 18.0 #6	14
NRG ELS7 18.0 #7	14
FEDGEN 13.8 #1	12
REFUSE 13.8 #D1	12
MALBRG3G 13.8 #S3	12
MALBRG2G 13.8 #C2	12
MALBRG1G 13.8 #C1	12
MESA CAL 66.0 #D7	11
BRODWYSC 13.8 #1	10
PASADNA1 13.8 #1	9
PASADNA2 13.8 #1	9
OLINDA 66.0 #1	7
EME WCG1 13.8 #1	7
EME WCG3 13.8 #1	7
EME WCG4 13.8 #1	7
EME WCG5 13.8 #1	7
EME WCG2 13.8 #1	7

OTC Generation Needed

The following lists the level of OTC generation capacity that is needed for the respective four RPS portfolios in order to mitigate the Serrano-Villa Park 230 kV constraint. These values correspond to the lower range of OTC generation need as they are located in more effective locations. The OTC requirements for the Western LA Basin are listed in the table below:

Table 3.3-18: OTC requirements for Western LA Basin to mitigate reliability issues

Portfolio	Minimum OTC Need (MW)
Trajectory	2,370
Environmental	1,870
Base	2,424
Time	2,460

Ellis Sub-Area

The most critical contingency for the Ellis sub-area is the loss of the Barre-Ellis 230 kV line followed by the loss of the Santiago-San Onofre #1 & #2 230 kV lines, which would cause voltage collapse

This constraint establishes the LCR numbers for the four RPS portfolios as noted in the table below:

Table 3.3-19: LCR for Ellis sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	531
Environmental	597
Base	511
Time	556

Generation Effectiveness Factors

The generators inside the sub-area have the same effectiveness factors.

OTC Generation Needed

To mitigate voltage collapse issues in the Ellis sub-area, 450 MW of OTC are required in all four portfolios.

El Nido Sub-Area

The most critical contingency for this area in all four portfolios is an N-2 outage of La Fresa-Redondo #1 and #2 230 kV lines. The limiting element is La Fresa-Hinson 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios, as listed in the table below.

Table 3.3-20: LCR for El Nido sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	619
Environmental	585
Base	568
Time	620

Generation Effectiveness Factors

The generators inside the sub-area have the same effectiveness factors.

OTC Generation Needed

No OTC units are required to mitigate reliability concern in the El Nido sub-area.

LCR Summary by portfolios

The following four tables summarize the OTC and LCR requirements for each portfolio. The tables also list the worst contingencies and limiting elements.

Table 3.3-21: Trajectory portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Trajectory	Overall LA Basin	12,961	339	13,300	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating) **	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western	7,529	268	7,797	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	472	59	531	Yes	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-22: Environmentally constrained portfolio — LCR and OTC requirements in LA Basin area and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)**	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western	6,695	869	7,584	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	473	124	597	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-23: ISO Base portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Base	Overall LA Basin	12,659	271	12,930	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating) **	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western	7,325	192	7,517	Yes	Serrano-Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Ellis	472	39	511	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-24: Time-constrained portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating) **	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western	6,954	443	7,397	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	495	61	556	Yes	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Conclusions

The main drivers behind OTC generation need in the LA Basin are the Western LA Basin area and the Ellis sub-area. The OTC generation needed across all four portfolios ranges from 1,870 MW to 2,460 MW, assuming most effective units are selected. The ‘HIGH’ or ‘LOW’ OTC levels are determined by using less effective or more effective OTC units, respectively. The following table is a summary of LCR and OTC requirements for the overall LA Basin and sub-areas.

Table 3.3-25: Summary of LCR and OTC requirements in LA Basin and its sub-areas

LCR Area	Trajectory High (MW)	Trajectory Low (MW)	Environmental High (MW)	Environmental Low (MW)	ISO Base Case High (MW)	ISO Base Case Low (MW)	Time-Constrained High (MW)	Time-Constrained Low (MW)
LA Basin	10,743	10,263	11,246	10,891	11,010	10,516	12,165	11,663
Western LA Basin	9,168	7,797	8,482	7,468	8,831	7,421	8,833	7,397
Ellis	531		597		511		556	
El Nido	619		585		568		620	
OTC	3,741	2,370	2,884	1,870	3,834	2,424	3,896	2,460

3.3.2.3.3 LCR Study Results — Big Creek/Ventura Area

To determine the OTC generation requirements for the Big Creek/Ventura area in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall Big Creek/Ventura;
- Moorpark sub-area;
- Rector sub-area; and
- Vestal sub-area.

Out of all these areas, only the Moorpark sub-area drives the need for OTC units. These OTC needs are also incorporated in the generation requirement for the overall Big Creek/Ventura area.

Area Definition for Big Creek

The transmission tie lines into the Big Creek/Ventura area are as follows:

1. Antelope 500/230kV banks #1 and #2;
2. Sylmar-Pardee #1 and #2 230 kV lines;
3. Vincent-Pardee #1 and #2 230 kV lines;
4. Vincent-Santa Clara 230 kV line.

These substations form the boundary surrounding the Big Creek/Ventura area:

1. Antelope 230 kV bus is in, Antelope 500 kV is out;
2. Pardee 230 kV bus is in, Sylmar 230 kV is out;
3. Pardee 230 kV bus is in, Vincent 230 kV is out; and
4. Santa Clara 230 kV bus is in, Vincent 230 kV is out.

The total 2021 substation load (bus bar level) within the defined area is 4,851 MW. Each portfolio has different line losses. Table 3.3-26 is the load and resource summary in the Big Creek/Ventura area for all four portfolios:

Table 3.3-26: Loads and Resource summary in Big Creek/Ventura area

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	4,947	4,946	4,948	4,942
Generation				
Existing NQC (2012)	5,232			
Existing OTC Capacity (2012)	2,075			
Distributed generation	4	419	61	95

Critical Contingency Analysis Summary

Overall Big Creek/Ventura Area

The most critical contingency for the overall Big Creek/Ventura area for the environmentally constrained and base portfolios is an N-1/T-1 contingency of Magunden-Omar 230 kV line and Antelope 500/230 kV bank #1 or #2. The limiting element is the remaining Antelope 500/230 kV bank. For the trajectory and time-constrained portfolios, the most critical contingency is the outage of Sylmar S-Pardee #1 or #2 line and Lugo-Victorville 230 kV line. The limiting element is the remaining Sylmar-Pardee 230 kV line. These two constraints establish the LCR numbers for the four portfolios as listed in the table below:

Table 3.3-27: LCR for overall Big Creek/Ventura area with identified contingencies

Portfolio	LCR (MW)
Trajectory	2,371
Environmental	2,604
Base	2,794
Time	2,653

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Eagle Rock-Sylmar 230 kV constraint for the overall Big Creek/Ventura area:

Table 3.3-28: Units with at least 5% effectiveness on Eagle Rock-Sylmar 230 kV constraint for overall Big Creek/Ventura

Generation	Effectiveness Factor (%)
RECTOR 66.0 #10	46
LAKEGEN 13.8 #1	45
ULTRAGEN 13.8 #1	45
VESTAL 66.0 #10	45
VESTAL 66.0 #E1	45
PANDOL 13.8 #1	45
PANDOL 13.8 #2	45
B CRK3-1 13.8 #1	44
B CRK3-1 13.8 #2	44
B CRK3-2 13.8 #4	44
B CRK 8 13.8 #81	44
B CRK 8 13.8 #82	44
B CRK2-3 7.2 #5	44
B CRK2-3 7.2 #6	44
B CRK2-1 13.8 #1	43
B CRK2-1 13.8 #2	43
B CRK2-2 7.2 #3	43
B CRK2-2 7.2 #4	43
B CRK1-1 7.2 #1	43
B CRK1-1 7.2 #2	43
B CRK1-2 13.8 #3	43
B CRK1-2 13.8 #4	43
PORTAL 4.8 #1	43
EASTWOOD 13.8 #1	43
EDMON8AP 14.4 #13	35
EDMON8AP 14.4 #14	35
EDMON2AP 14.4 #2	35
EDMON1AP 14.4 #1	35
EDMON3AP 14.4 #3	35
PSTRIAG1 18.0 #G1	35
OSO A P 13.2 #1	34
OSO B P 13.2 #8	34
ALAMO SC 13.8 #1	34
WARNE1 13.8 #1	29
WARNE2 13.8 #1	29
SAUGUS 66.0 #11	23
SAUGUS 66.0 #10	23
TENNGEN1 13.8 #D1	23
TENNGEN2 13.8 #D2	23
PITCHGEN 13.8 #D1	23
APPGEN1G 13.8 #1	23

Generation	Effectiveness Factor (%)
APPGEN2G 13.8 #2	23
APPGEN3G 13.8 #3	23
MOORPARK 66.0 #10	22
GOLETA 66.0 #E1	21
ELLWOOD 13.8 #1	21
S.CLARA 66.0 #E1	20
CHARMIN 13.8 #1	20
OXGEN 13.8 #D1	20
PROCGEN 13.8 #D1	20
CAMGEN 13.8 #D1	20
MANDLY1G 13.8 #1	19
MANDLY3G 16.0 #3	19
MCGPKGEN 13.8 #1	19

OTC Generation Needed

The need for OTC units in the overall Big Creek/Ventura area is established specifically by the Moorpark sub-area. Approximately 430 MW of OTC capacity is required across all four RPS portfolios to mitigate reliability issues in the Moorpark sub-area. This OTC capacity is counted towards the total LCR need for the overall Big Creek/Ventura area. The OTC generation requirements for the overall Big Creek/Ventura area by portfolios are listed in the table below.

Table 3.3-29: OTC requirements for Moorpark sub-area to mitigate reliability issue

Portfolio	Min OTC Need (MW)
Trajectory	430
Environmental	430
Base	430
Time	430

Moorpark Sub-area

The most critical contingency for the Moorpark sub-area is the N-1 outage followed by N-2 outage-loss of Pardee-Moorpark #1 230 kV line and Pardee-Moorpark #2 and #3 230 kV lines. This would result in a voltage collapse. To mitigate this voltage collapse, about 430 MW of OTC units are required as part of the LCR for this sub-area. This constraint establishes the LCR numbers for the four portfolios as listed in the following table:

Table 3.3-30: LCR for Moorpark sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	735
Environmental	642/857
Base	651/781
Time	673/803

Generation Effectiveness Factors

Generators inside this sub-pocket have the same effectiveness on this limiting constraint.

OTC Generation Needed

Approximately 430 MW of OTC capacity is needed across all four portfolios in order to mitigate the voltage collapse concern. The OTC requirements by portfolios are listed in the table below.

Table 3.3-31: OTC requirements for Moorpark sub-area to mitigate reliability issues

Portfolio	Min OTC Need (MW)
Trajectory	430
Environmental	430
Base	430
Time	430

Rector Sub-Area

The most critical contingency for the Rector sub-area is the L-1/G-1 outage of Vestal-Rector #1 or #2 230 kV line and Eastwood generation. The limiting element is the remaining Rector-Vestal 230 kV line. This constraint establishes the LCR numbers for the four portfolios as noted in the table below.

Table 3.3-32: LCR for Rector sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	653
Environmental	618
Base	600
Time	573

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Vestal-Rector 230 kV constraint for the Rector sub-area:

Table 3.3-33: Units with at least 5% effectiveness on Vestal-Rector 230 kV constraint for Rector sub-area

Generation	ID	Effectiveness Factor (%)
KAWGEN	1	45
EASTWOOD	1	41
B CRK1-1	1	41
B CRK1-1	2	41
B CRK1-2	3	41
B CRK1-2	4	41
PORTAL	1	41
B CRK2-1	1	40
B CRK2-1	2	40
B CRK2-2	3	40
B CRK2-2	4	40
B CRK 8	81	40
B CRK 8	82	40
B CRK2-3	5	39
B CRK2-3	6	39
B CRK3-1	1	39
B CRK3-1	2	39
B CRK3-2	3	39
B CRK3-2	4	39
B CRK3-3	5	39
MAMOTH1G	1	39
MAMOTH2G	2	39
B CRK 4	41	38
B CRK 4	42	38

OTC Generation Needed

No OTC units are required to mitigate reliability concern in the Rector sub-area.

Vestal Sub-Area

The most critical contingency for this area in all four RPS portfolios is an L-1/G-1 outage of the Magunden-Vestal 230 kV #1 or #2 line and Eastwood generation. The limiting element is the remaining Magunden-Vestal 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios as noted in the following table.

Table 3.3-34: LCR for Vestal sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	786
Environmental	835
Base	773
Time	806

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Magunden-Vestal 230 kV constraint for the Vestal sub-area:

Table 3.3-35: Units with at least 5% effectiveness on Magunden-Vestal 230 kV constraint for Vestal sub-area

Gen Name	Gen ID	Effectiveness Factor (%)
LAKEGEN	1	46
PANDOL	1	45
PANDOL	2	45
ULTRAGEN	1	45
KR 3-1	1	45
KR 3-2	2	45
VESTAL	1	45
KAWGEN	1	45
EASTWOOD	1	24
B CRK1-1	1	24
B CRK1-1	2	24
B CRK1-2	3	24
B CRK1-2	4	24
B CRK2-1	1	24
B CRK2-1	2	24
B CRK2-2	3	24
B CRK2-2	4	24
B CRK2-3	5	24
B CRK2-3	6	24
B CRK 8	81	24
B CRK 8	82	24
PORTAL	1	24
B CRK3-1	1	23
B CRK3-1	2	23
B CRK3-2	3	23

OTC Generation Needed

No OTC units are required to mitigate reliability concern in Vestal sub-area.

LCR Summary by Portfolios

The following four tables summarize the OTC and LCR requirements for each portfolio. The tables also list the worst contingencies and limiting elements.

Table 3.3-36: Trajectory portfolio — LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Trajectory	Overall Big Creek Ventura	2,367	4	2,371	No	Remaining Sylmar-Pardee 230 kV line	Sylmar-Pardee #1 and #2 + Pastoria Generation
	Moorpark	735	0	735	Yes	Voltage Collapse	Pardee-Moorpark #1 230kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	653	0	653	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	786	0	786	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-37: Environmentally Constrained LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Environmentally constrained	Overall Big Creek Ventura	2,185	419	2,604	No	Antelope 500/230 kV bank #1 or #2	Antelope 500/230 kV Bank #1 or #2 + Magunden-Omar 230 kV line (and the associated generation)
	Moorpark	502	140	642/857	Yes	Voltage Collapse	Pardee-Moorpark #1 230 kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	489	129	618	No	Vestal - Rector #1 or #2 line	Vestal - Rector #1 or #2 line + Eastwood gen
	Vestal	677	158	835	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-38: ISO Base portfolio — LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Base	Overall Big Creek Ventura	2,377	61	2,794	No	Antelope 500/230 kV Bank #1 or #2	Antelope 500/230kV bank #1 or #2 + Magunden- Omar 230 kV line (and the associated generation)
	Moorpark	637	14	651	Yes	Voltage Collapse	Pardee-Moorpark #1 230kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	584	16	600	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	755	18	773	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-39: Time portfolio — LCR and OTC requirements in Big Creek/Ventura area and its sub-areas

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Time	Overall Big Creek Ventura	2,558	95	2,653	No	Antelope 500/230 kV Bank #1 or #2	Antelope 500/230 kV bank #1 or #2 + Magunden-Omar 230kV line (and the associated generation)
	Moorpark	632	41	673/803	Yes	Voltage Collapse	Pardee-Moorpark #1 230 kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	555	18	573	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	785	21	806	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230kV #1 or #2 line + Eastwood gen

Conclusions

The main driver for OTC generation need in the Big Creek/Ventura area is the local capacity requirement for the Moorpark sub-area. Minimum OTC need across all four portfolios is 430 MW. The following table is a summary of LCR and OTC requirements for the overall Big Creek/Ventura area.

Table 3.3-40: Summary of LCR and OTC requirements in Big Creek/Ventura area and sub-areas

LCR Area	Trajectory (MW)	Environmental (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Big Creek / Ventura	2,371	2,604	2,794	2,653
Rector	474	597	511	556
Vestal	638	585	568	620
OTC	430	430	430	430

3.3.2.3.4 LCR Study Results — San Diego Area

To determine the OTC generation need for San Diego area in 2021, an LCR study was performed for the following four RPS portfolios: trajectory;

- environmentally constrained;
- ISO Base; and
- time-constrained

The following areas were examined for LCR generation requirements:

- San Diego overall; and
- Greater Imperial Valley – San Diego (IV-San Diego)

Area Definition for San Diego

The transmission tie lines forming a boundary around San Diego include the following:

1. Imperial Valley-Miguel 500 kV line;
2. Imperial Valley-Central 500 kV line;
3. Otay Mesa-Tijuana 230 kV line;
4. San Onofre-San Luis Rey #1 230 kV line;
5. San Onofre-San Luis Rey #2 230 kV line;
6. San Onofre-San Luis Rey #3 230 kV line;
7. San Onofre-Talega #1 230 kV line; and
8. San Onofre-Talega #2 230 kV line.

The substations that delineate the San Diego area are:

1. Imperial Valley is out, Miguel is in;
2. Imperial Valley is out, Central is in;
3. Otay Mesa is in, Tijuana is out;
4. San Onofre is out, San Luis Rey is in;

5. San Onofre is out, San Luis Rey is in;
6. San Onofre is out, San Luis Rey is in;
7. San Onofre is out, Talega is in; and
8. San Onofre is out, Talega is in.

The total 2021 substation load (bus bar level) within the defined area is 5,590 MW. Each portfolio has different losses. The following table shows the load and resource summary in the San Diego area in 2021 for all four RPS portfolios:

Table 3.3-41: Loads and resource summary in San Diego area

Itemized details	Trajectory, MW	Environmentally Constrained, MW	ISO Base, MW	Time-Constrained, MW
Total 1-in-10 Load + Losses	5,745	5,751	5,745	5,741
Generation				
Existing NQC (2012)	3,049			
Existing OTC NQC (2012)	950			
Distributed generation	52	402	104	81

Critical Contingency Analysis Summary
Overall San Diego Area

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Sunrise Powerlink and Southwest Powerlink (SWPL) overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW). A post-contingency import limit of 3,500 MW is not the most limiting element for this condition. The limiting constraint for this contingency is the South of SONGS Separation Scheme. This constraint establishes LCR requirements for the four portfolios as shown in the table below.

Table 3.3-42: Overall San Diego area LCR requirements

Portfolios	LCR, MW			OTC Need, MW	Constraint	Contingency
	Non-D.G.	D.G.	Total			
Trajectory	2,852	31	2,883	950	South of SONGS separation Scheme	Otay Mesa (G-1) + SWPL + SRPL
Environmentally constrained	2,660	194	2,854	650		
ISO Base	2,822	42	2,864	650		
Time-constrained	2,791	65	2,856	840		

Generation Effectiveness Factors

All units within this area have the same effectiveness factor. Units outside of this area are not effective for the contingency considered above.

Greater Imperial Valley — San Diego Area

The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW), while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This constraint establishes LCR requirements for four portfolios as shown in the table below.

Table 3.3-43: Greater IV-San Diego area LCR requirements

Portfolios	LCR (MW)			OTC Need (MW)	Constraint	Contingency
	Non-D.G.	D.G.	Total			
Trajectory	3,260	31	3,291*	0	P44 rating of 2500 MW	Otay Mesa (G-1) + IV-NG
Environmentally Constrained	2,910	194	3,104	0		
ISO Base	2,926	42	2,968	0		
Time Constrained	3,207	65	3,272*	210		

* Assuming a fix for voltage deviations in Western Arizona sub transmission.

Generation Effectiveness Factors

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Conclusions

The LCR study for the San Diego area has shown the need for OTC generation units. The need was driven by the South of SONGS Separation Scheme for all portfolios and Path 44 rating of 2,500 MW for only the time-constrained portfolio.

The following table is a summary of LCR and OTC generation requirements for the San Diego and IV-San Diego areas.

Table 3.3-44: Summary of LCR and OTC generation requirements

LCR Area	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base (MW)	Time-Constrained (MW)
San Diego	2,883**	2,854**	2,864**	2,856**
IV – San Diego	3,291	3,104	2,968	3,272
OTC Range*	531* - 950	231* - 650	231* - 650	421* - 840

*Lower OTC range value corresponds to the use of SDG&E-proposed generation included in the Long-Term Procurement Plan.

**Load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency.

3.4 Assembly Bill 1318 (AB1318) Reliability Studies

3.4.1 Background, Methodology and Assumptions

Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009) requires the CARB, in consultation with the ISO, CEC, CPUC and the SWRCB to prepare a report for the governor and legislature that evaluates the electrical system's reliability needs within the South Coast Air Basin. The report is required to include recommendations regarding the most effective and efficient means of meeting reliability needs while ensuring compliance with state and federal law. In collaboration with the state agencies, in 2010, the ISO prepared an interim report: *Draft Work Plan on the Assessment of Electrical System Reliability Needs in South Coast Air Basin and Recommendations on Meeting those Needs*.[23] This report summarizes existing reliability studies for the ISO-controlled grid in the South Coast Air Basin and provides an overview of studies to be performed in the ISO's 2011/2012 transmission planning cycle to meet AB 1318 objectives. The following discussion provides the details of the study scope.

For the AB 1318 study, CARB is interested in determining the maximum credible range of offsets rather than a single "most likely" range. An advantage of the maximum range approach is that it could be determined using *a priori* knowledge by strategically evaluating the ranges of assumptions and modeling conventions to provide potential maximum or minimum values, which would encompass the most likely range scenario. A most likely range would probably require more time to debate and reach consensus among various competing interest groups and may not result in a deliverable product for CARB by the end of the year. Given the dynamics of renewable generation development, as well as the challenge of demand side management, it is more logical to evaluate the maximum and minimum range of potential emission offsets at this time

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[23] http://www.arb.ca.gov/energy/esr-sc/0215-workshop/ab_1318_draft_work_plan.pdf

until further clarity of the RPS and demand side management development trend is known. Although the goal is to identify and assess various assumptions that lead to high and low offsets, the analytical plan also calls for sensitivity investigations. If all combinations of input assumptions are examined, there are still many cases contributing to the two study scenarios, and much additional time and resources would be required to assess them. This proposal suggests an approach that identifies the most important cases for near-term analyses.

The analytic approach uses power flow models to determine thermal violations, and transient and post transient stability analyses. The results of these studies were examined applying the ISO's techniques for determining local capacity area requirements.[24] The outcomes provided minimum capacity additions to satisfy local and zonal reliability standards. With the capacity additions for each scenario established, supplemental analyses will be performed by CARB staff, working in conjunction with the CEC, to translate the capacity additions into offsets associated with that capacity development.

3.4.1.1 *High End of Emission Offset Range*

The purpose of this study is to identify the upper end of the offset range for non-nuclear thermal generation in the L.A. Basin under various 33 percent renewable generation and OTC development scenarios utilizing the latest CEC adopted demand forecast. Offsets are both emission reduction credits (ERCs) and internal bank credits that would have to be surrendered for capacity that elected to use South Coast Air Quality Management District (SCAQMD) Rule 1304(a)(2). Comments identify remaining issues that may be resolved in future transmission planning study cycles if they cannot be resolved at this time. This approach is used because of the need to complete the capacity requirements studies for CARB this year. Four high end scenarios were studied for the high net-load conditions (i.e., CEC's adopted 1-in-10 year heat wave load without incremental energy efficiency or demand responses).

Study Combinations = [1 load (latest official CEC-adopted demand forecast)* 4 RPS scenarios * 1 OTC generation scenario[25]] = 4 cases

3.4.1.2 *Low End of Emission Offset Range*

The purpose of this study is to identify the lower end of the offset range if policy-driven demand side management measures (i.e., incremental energy efficiency, combined heat and power, demand response) were to materialize. The CPUC and the CEC refer to this load condition as the mid net load scenario. In many cases, the values chosen are the opposite of those selected for the high end of the offset range scenario. One low end scenario was studied:

[24] ISO, *2013-2015 Local Capacity Technical Analysis: Final Report and Study Results*, December 2010.

[25] Local capacity requirement scenario: This scenario will determine the minimum OTC generation need that enables the load serving entities to meet applicable national, regional and ISO reliability requirements.

- Combinations = 1 load (mid net load[26])* 1 RPS (environmentally constrained) * 1 OTC generation study scenario = 1 case.

Like the study described in the section above, to provide data inputs to CARB staff for further estimates of emission offset needs, this study will be performed for the environmentally constrained case to provide the lower end of the emission offset range.

3.4.2 AB 1318 Reliability Assessment — Study Results

Because OTC and AB 1318 reliability studies share some common study objectives for the LA Basin (the area in which SCAQMD has jurisdiction), please refer to the write-ups in section 3.3.2 (OTC Reliability Assessment) for related study results for the AB 1318 reliability assessment. The following is a summary of the study scope for AB 1318 reliability assessment:

1. Reliability assessment of the LA Basin LCR area for four RPS portfolios at peak load conditions (high net load): The four portfolios are trajectory, environmentally constrained, ISO base case and time-constrained. The purpose of these studies is to identify whether there is a reliability need to run OTC plants, and if there is, what is the OTC generation level needed during peak load conditions. Studies at peak load conditions establish local capacity requirements for higher bound conditions. Additionally, these assessments utilized the official CEC-adopted demand forecast for 1-in-10 year heat wave load projection. The CEC demand forecast includes committed energy efficiency.
2. Per the request from the state agencies (CARB, CEC and CPUC), the ISO also performed an LCR assessment for mid net load conditions for the environmentally constrained study case as sensitivity studies: The results for this study provide for lower bound condition for informational purposes. For this study, the ISO utilized uncommitted incremental energy efficiency, modeled at specific load buses, as provided by the CPUC and CEC. Incremental demand resources are treated as potential resources, if they materialize. Because of the uncommitted nature of these programs, the ISO considers these studies as sensitivity studies.
3. Transient stability assessment for on-peak and off-peak load conditions. For on-peak load conditions, the assessment was performed for the trajectory and environmentally constrained RPS portfolios. For the off-peak condition, assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation modeled, would still meet the WECC transient stability reliability criteria.
4. Loads and resource assessment for zonal (NP26 and SP26) and ISO balancing authority: The purpose of this assessment is to provide preliminary

[26] Mid net load scenario includes uncommitted incremental energy efficiency, demand response and combined heat and power.

long-term review of the adequacy of future generation to serve loads in the 2021 time frame under two load scenarios: 1-in-2 year and 1-in-10 year heat wave load conditions. This is similar to the ISO annual summer assessment, except that it looks out ten years into the future, whereas the summer assessment evaluates adequacy of resources for the next summer condition. For this assessment, the minimum OTC generation requirement was modeled. In addition, NQC

5. values for renewable generation at peak load and some demand response was modeled.

3.4.2.1 Study Results

The results of study items #1, 3 and 4 are provided in Section 3.3.2 (OTC Reliability Assessment Study Results). In this section, only new study results for item #2 above are reported. The following table includes assumptions provided by the CPUC and CEC in regards to assumptions of incremental uncommitted energy efficiency and demand response values.

Table 3.4-1: State energy agencies' provided assumptions on incremental EE & DR

Load Serving Entities	2021 Incremental EE (MW)	2021 Demand Response (MW)
PG&E	2,275	1,523
SCE	2,461	2,829
SDG&E	496	283

The next table provides the summary study results for the mid-net load assumptions with incremental uncommitted energy efficiency and demand response. The results indicated that, if incremental energy efficiency and demand response were to fully materialize as assumed, the resulting OTC generation need would be about 42 percent of the need under high-net load condition for the same RPS portfolio (environmentally constrained), or about 33 percent of the highest OTC generation need under a different RPS portfolio (time-constrained).

For study conclusions, please refer to section 3.3.2.

Table 3.4-2: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	LA Basin Overall	9,242	1,519	10,761	No	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA	5,589	869	6,458	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Western LA OTC Range		802 - 1,275 MW				OTC need ranges from most effective to less effective generation
	Ellis	470	124	594	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	336	91	427	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

* Mira Loma 500/230kV Bank #2 has a 1-Hr emergency rating of 1792 MVA (assuming up to 600 MW load shed/transfer after 1-Hr). If this rating is utilized then Path 26 flow becomes the next limiting constraint.

** In addition to generation requirements, three 79 MVAR shunt capacitors were modeled to mitigate voltage collapse concern. The voltage concern was caused by less dispatch of generation due to lower load that was off-set by the state agencies' assumptions of uncommitted energy efficiency for the mid net load level.

SECTION III: POLICY-DRIVEN NEED ASSESSMENT

Chapter 4

Meeting 33% Renewables Portfolio Standard — Study Assumptions and Methodology

4.1 33% RPS Portfolios

In consultation with interested parties, CPUC staff developed four renewable generation scenarios that represented possible RPS futures in 2020. These scenarios considered transmission constraints, cost, commercial interest, environmental concerns and timing of development. The four scenarios vary by technology, location and other characteristics. The CPUC proposed that the ISO in its 2011/2012 Transmission Planning Process study three of the four RPS scenarios developed for the 2010 LTPP proceeding: trajectory scenario, environmentally constrained scenario and time-constrained scenario. In addition, the CPUC proposed that the ISO study an updated version of the LTPP's cost-constrained scenario as the base case. The base case represents the renewable scenario that is considered to be more likely to occur than the other three scenarios which are referred to as sensitivity or stress scenarios. The base and sensitivity scenarios are utilized to perform a least regrets transmission need analysis as described in the Chapter 1 discussion about Phase 2 of the transmission planning process and in Tariff section 24.4.6.6. These updates include the addition of 1,384 MW of solar photovoltaic to the discounted core, to correct an error in the previous scenarios and reflect approval of the Renewable Auction Mechanism. In addition, they include adjusted assumptions about the cost and capacity of new transmission for several competitive renewable energy zones (CREZ) based on the ISO's 2010/2011 plan and FERC filings, which are Imperial, Kramer, Mountain Pass, Palm Springs, Riverside East, Pisgah, Solano and Westlands.

These four portfolios were reviewed by stakeholders during a July 8, 2011 ISO stakeholder meeting. Several stakeholders cited the need to consider the Desert Renewable Energy Conservation Plan (DRECP) and the findings that developing renewable generation on degraded land in West Mohave in the development of the portfolios. The stakeholders making this request were: the CEC, Nature Conservancy, Center for Energy Efficiency and Renewable Technologies, and National Resource Defense Council. The ISO in consultation with the CPUC and CEC increased the amount of renewable generation in the Kramer CREZ in the base portfolio from 62 MW to 362 MW. A corresponding amount of generation was reduced in the Wyoming and Colorado locations based on lower amounts in these locations observed in the environmentally constrained scenario. These CPUC proposed renewable portfolios, as modified by the ISO, were studied by the ISO in the policy-driven transmission planning assessments within the ISO balancing authority.

4.1.1 Capacity and Energy of portfolios

The installed capacity and energy per year of each portfolio by location and technology are shown in the following tables.

Table 4.1-1 Base portfolio (MW)

	Base portfolio (MW)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	450	**450**
Arizona	-	-	-	-	290	-	-	-	**290**
British Columbia	50	-	-	-	-	-	-	-	**50**
Carrizo South	-	-	-	-	900	-	-	-	**900**
Colorado	-	-	-	-	-	-	-	223	**223**
Distributed Solar - Other	-	-	-	-	-	-	-	-	**-**
Distributed Solar - PG&E	-	-	-	-	-	773	-	-	**773**
Distributed Solar - SCE	-	-	-	-	-	750	-	-	**750**
Distributed Solar - SDGE	-	-	-	-	-	78	-	-	**78**
Imperial	-	-	1,247	-	49	-	300	97	**1,693**
Kramer	-	-	-	-	-	-	362	-	**362**
Montana	-	-	-	-	-	-	-	300	**300**
Mountain Pass	-	-	-	-	-	-	410	113	**523**
Nevada C	-	-	-	-	50	-	400	-	**450**
New Mexico	-	32	20	-	-	-	-	895	**947**
NonCREZ	14	168	-	-	50	-	-	420	**652**
Northwest	-	97	-	-	-	-	-	614	**711**
Palm Springs	-	-	-	-	-	-	-	178	**178**
Pisgah	-	-	-	-	275	-	-	-	**275**
Remote DG (Brownfield) - Other	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	206	-	-	**206**
Remote DG (Brownfield) - SCE	-	-	-	-	-	63	-	-	**63**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	9	-	-	**9**
Riverside East	-	-	-	-	550	-	642	-	**1,192**
Round Mountain	-	-	22	-	-	-	-	78	**100**
San Bernardino - Lucerne	-	-	-	-	-	-	-	261	**261**
San Diego South	-	21	-	-	-	-	-	678	**699**
Solano	-	-	-	-	-	-	-	535	**535**
Tehachapi	-	37	-	-	-	-	-	3,452	**3,489**
Utah-Southern Idaho	21	-	134	13	-	-	-	90	**258**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	2	-	-	-	-	-	-	410	**412**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	412	-	-	**412**
Remote DG (Greenfield) - SCE	-	-	-	-	-	126	-	-	**126**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	17	-	-	**17**
Total in-State	14	226	1,269	-	1,824	2,435	1,714	5,813	**13,295**
Total Out-of-State	73	129	154	13	340	-	400	2,982	**4,091**
Total	87	355	1,423	13	2,164	2,435	2,114	8,795	**17,386**

Table 4.1-2 Base portfolio (GWh/year)

	Base portfolio (GWh/year)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	1,230	**1,230**
Arizona	-	-	-	-	737	-	-	-	**737**
British Columbia	372	-	-	-	-	-	-	-	**372**
Carrizo South	-	-	-	-	1,960	-	-	-	**1,960**
Colorado	-	-	-	-	-	-	-	621	**621**
Distributed Solar - Other	-	-	-	-	-	-	-	-	**-**
Distributed Solar - PG&E	-	-	-	-	-	1,566	-	-	**1,566**
Distributed Solar - SCE	-	-	-	-	-	1,508	-	-	**1,508**
Distributed Solar - SDGE	-	-	-	-	-	161	-	-	**161**
Imperial	-	-	9,399	-	125	-	701	275	**10,501**
Kramer	-	-	-	-	-	-	847	-	**847**
Montana	-	-	-	-	-	-	-	994	**994**
Mountain Pass	-	-	-	-	-	-	958	306	**1,264**
Nevada C	-	-	-	-	127	-	935	-	**1,062**
New Mexico	-	238	156	-	-	-	-	2,533	**2,927**
NonCREZ	95	1,251	-	-	117	-	-	1,245	**2,708**
Northwest	-	722	-	-	-	-	-	1,571	**2,293**
Palm Springs	-	-	-	-	-	-	-	532	**532**
Pisgah	-	-	-	-	643	-	-	-	**643**
Remote DG (Brownfield) - Other	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	419	-	-	**419**
Remote DG (Brownfield) - SCE	-	-	-	-	-	140	-	-	**140**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	19	-	-	**19**
Riverside East	-	-	-	-	1,283	-	1,623	-	**2,906**
Round Mountain	-	-	153	-	-	-	-	220	**373**
San Bernardino - Lucerne	-	-	-	-	-	-	-	753	**753**
San Diego South	-	156	-	-	-	-	-	1,939	**2,095**
Solano	-	-	-	-	-	-	-	1,757	**1,757**
Tehachapi	-	276	-	-	-	-	-	9,728	**10,004**
Utah-Southern Idaho	158	-	970	60	-	-	-	229	**1,417**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	16	-	-	-	-	-	-	1,290	**1,306**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	837	-	-	**837**
Remote DG (Greenfield) - SCE	-	-	-	-	-	282	-	-	**282**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	38	-	-	**38**
Total in-State	95	1,683	9,552	-	4,128	4,969	4,129	16,754	**41,311**
Total Out-of-State	546	961	1,126	60	864	-	935	8,467	**12,959**
Total	641	2,643	10,678	60	4,992	4,969	5,064	25,221	**54,269**

Table 4.1-3 Trajectory portfolio (MW)

	Trajectory portfolio (MW)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	886	**886**
Arizona	-	-	-	-	290	-	-	-	**290**
British Columbia	-	2	-	-	-	-	-	-	**2**
Carrizo South	-	-	-	-	900	-	-	-	**900**
Colorado	-	-	-	-	-	-	-	420	**420**
Distributed Solar - Other	-	-	-	-	-	-	-	-	**-**
Distributed Solar - PG&E	-	-	-	-	-	500	-	-	**500**
Distributed Solar - SCE	-	-	-	-	-	500	-	-	**500**
Distributed Solar - SDGE	-	-	-	-	-	52	-	-	**52**
Imperial	-	-	667	-	356	-	-	179	**1,202**
Kramer	-	-	-	-	-	-	62	-	**62**
Montana	-	-	-	-	-	-	-	300	**300**
Mountain Pass	-	-	-	-	300	-	410	178	**888**
Nevada C	-	-	-	-	50	-	400	-	**450**
New Mexico	-	32	-	-	-	-	-	-	**32**
NonCREZ	166	105	-	-	283	-	-	-	**554**
Northwest	-	-	-	16	-	-	-	2,344	**2,360**
Palm Springs	-	-	-	-	-	-	-	77	**77**
Pisgah	-	-	-	-	575	-	1,200	-	**1,775**
Remote DG (Brownfield) - Other	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	-	-	-	**-**
Riverside East	-	-	-	-	550	-	1,012	-	**1,562**
Round Mountain	-	-	-	-	-	-	-	78	**78**
San Bernardino - Lucerne	7	-	-	-	-	-	-	42	**49**
San Diego South	-	21	-	-	-	-	-	379	**400**
Solano	3	-	-	-	-	-	-	1,126	**1,129**
Tehachapi	2	-	-	-	1,364	-	105	2,975	**4,446**
Utah-Southern Idaho	-	-	154	-	-	-	-	104	**258**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	-	-	-	-	-	-	-	96	**96**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	-	-	-	**-**
Total in-State	178	126	667	-	4,328	1,052	2,789	5,034	**14,174**
Total Out-of-State	-	34	154	16	340	-	400	4,150	**5,093**
Total	178	160	822	16	4,668	1,052	3,189	9,184	**19,267**

Table 4.1-4 Trajectory portfolio (GWh/year)

	Trajectory portfolio (GWh/year)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	2,422	**2,422**
Arizona	-	-	-	-	736	-	-	-	**736**
British Columbia	-	12	-	-	-	-	-	-	**12**
Carrizo South	-	-	-	-	1,960	-	-	-	**1,960**
Colorado	-	-	-	-	-	-	-	1,169	**1,169**
Distributed Solar - Other	-	-	-	-	-	-	-	-	**-**
Distributed Solar - PG&E	-	-	-	-	-	1,015	-	-	**1,015**
Distributed Solar - SCE	-	-	-	-	-	991	-	-	**991**
Distributed Solar - SDGE	-	-	-	-	-	99	-	-	**99**
Imperial	-	-	4,844	-	843	-	-	505	**6,193**
Kramer	-	-	-	-	-	-	145	-	**145**
Montana	-	-	-	-	-	-	-	994	**994**
Mountain Pass	-	-	-	-	762	-	958	457	**2,178**
Nevada C	-	-	-	-	127	-	935	-	**1,062**
New Mexico	-	238	-	-	-	-	-	-	**238**
NonCREZ	1,164	782	-	-	660	-	-	-	**2,606**
Northwest	-	-	-	48	-	-	-	5,996	**6,044**
Palm Springs	-	-	-	-	-	-	-	217	**217**
Pisgah	-	-	-	-	1,364	-	2,805	-	**4,169**
Remote DG (Brownfield) - Other	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	-	-	-	**-**
Riverside East	-	-	-	-	1,282	-	2,488	-	**3,770**
Round Mountain	-	-	-	-	-	-	-	220	**220**
San Bernardino - Lucerne	49	-	-	-	-	-	-	119	**168**
San Diego South	-	156	-	-	-	-	-	1,070	**1,226**
Solano	21	-	-	-	-	-	-	3,452	**3,473**
Tehachapi	14	-	-	-	2,808	-	245	8,399	**11,466**
Utah-Southern Idaho	-	-	1,116	-	-	-	-	263	**1,379**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	-	-	-	-	-	-	-	317	**317**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	-	-	-	**-**
Total in-State	1,248	938	4,844	-	9,679	2,105	6,642	14,439	**39,896**
Total Out-of-State	-	250	1,116	48	864	-	935	11,160	**14,373**
Total	1,248	1,188	5,961	48	10,542	2,105	7,577	25,599	**54,269**

Table 4.1-5 Environmentally constrained portfolio (MW)

	Environmentally constrained portfolio (MW)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	450	**450**
Arizona	-	-	-	-	290	-	-	-	**290**
British Columbia	50	2	-	-	-	-	-	-	**52**
Carrizo South	-	-	-	-	900	-	-	-	**900**
Colorado	-	-	-	-	-	-	-	-	**-**
Distributed Solar - Other	-	-	-	-	-	1,522	-	-	**1,522**
Distributed Solar - PG&E	-	-	-	-	-	1,757	-	-	**1,757**
Distributed Solar - SCE	-	-	-	-	-	2,345	-	-	**2,345**
Distributed Solar - SDGE	-	-	-	-	-	397	-	-	**397**
Imperial	-	-	239	-	108	-	-	-	**347**
Kramer	-	-	-	-	-	-	62	-	**62**
Montana	-	-	-	-	-	-	-	300	**300**
Mountain Pass	-	-	-	-	-	-	-	-	**-**
Nevada C	-	-	96	3	50	-	400	-	**549**
New Mexico	-	58	20	-	-	-	-	-	**78**
NonCREZ	167	233	-	-	50	-	-	-	**450**
Northwest	-	97	-	128	-	-	-	614	**839**
Palm Springs	-	-	-	-	-	-	-	178	**178**
Pisgah	-	-	-	-	275	-	-	-	**275**
Remote DG (Brownfield) - Other	-	-	-	-	-	571	-	-	**571**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	1,842	-	-	**1,842**
Remote DG (Brownfield) - SCE	-	-	-	-	-	564	-	-	**564**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	78	-	-	**78**
Riverside East	-	-	-	-	550	-	642	-	**1,192**
Round Mountain	-	22	-	-	-	-	-	78	**100**
San Bernardino - Lucerne	7	91	-	-	-	-	-	42	**140**
San Diego South	-	21	-	-	-	-	-	379	**400**
Solano	3	-	-	-	-	-	-	297	**300**
Tehachapi	2	37	-	-	-	-	-	3,452	**3,491**
Utah-Southern Idaho	14	-	154	-	-	-	-	90	**258**
Westlands	-	-	-	-	800	-	-	-	**800**
Wyoming	2	-	-	2	-	-	-	-	**4**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	-	-	-	**-**
Total in-State	179	404	239	-	2,683	9,076	704	4,426	**17,711**
Total Out-of-State	66	157	270	133	340	-	400	1,454	**2,819**
Total	245	560	509	133	3,023	9,076	1,104	5,880	**20,529**

Table 4.1-6 Environmentally constrained portfolio (GWh/yr)

	Environmentally constrained portfolio (GWh/year)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	1,230	**1,230**
Arizona	-	-	-	-	737	-	-	-	**737**
British Columbia	372	12	-	-	-	-	-	-	**384**
Carrizo South	-	-	-	-	1,959	-	-	-	**1,959**
Colorado	-	-	-	-	-	-	-	-	**-**
Distributed Solar - Other	-	-	-	-	-	2,890	-	-	**2,890**
Distributed Solar - PG&E	-	-	-	-	-	3,313	-	-	**3,313**
Distributed Solar - SCE	-	-	-	-	-	4,658	-	-	**4,658**
Distributed Solar - SDGE	-	-	-	-	-	798	-	-	**798**
Imperial	-	-	1,837	-	255	-	-	-	**2,092**
Kramer	-	-	-	-	-	-	145	-	**145**
Montana	-	-	-	-	-	-	-	994	**994**
Mountain Pass	-	-	-	-	-	-	-	-	**-**
Nevada C	-	-	673	10	127	-	935	-	**1,745**
New Mexico	-	418	156	-	-	-	-	-	**573**
NonCREZ	1,164	1,735	-	-	117	-	-	-	**3,016**
Northwest	-	722	-	383	-	-	-	1,571	**2,676**
Palm Springs	-	-	-	-	-	-	-	531	**531**
Pisgah	-	-	-	-	643	-	-	-	**643**
Remote DG (Brownfield) - Other	-	-	-	-	-	1,222	-	-	**1,222**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	3,740	-	-	**3,740**
Remote DG (Brownfield) - SCE	-	-	-	-	-	1,258	-	-	**1,258**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	171	-	-	**171**
Riverside East	-	-	-	-	1,283	-	1,623	-	**2,906**
Round Mountain	-	162	-	-	-	-	-	221	**383**
San Bernardino - Lucerne	49	678	-	-	-	-	-	119	**845**
San Diego South	-	156	-	-	-	-	-	1,070	**1,226**
Solano	21	-	-	-	-	-	-	838	**859**
Tehachapi	14	276	-	-	-	-	-	9,728	**10,018**
Utah-Southern Idaho	101	-	1,116	-	-	-	-	229	**1,446**
Westlands	-	-	-	-	1,781	-	-	-	**1,781**
Wyoming	16	-	-	11	-	-	-	-	**27**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&E	-	-	-	-	-	-	-	-	**-**
Total in-State	1,248	3,007	1,837	-	6,039	18,050	1,768	12,507	**44,457**
Total Out-of-State	489	1,152	1,945	404	864	-	935	4,023	**9,812**
Total	1,737	4,159	3,782	404	6,903	18,050	2,703	16,530	**54,269**

Table 4.1-7 Time-constrained portfolio (MW)

	Time constrained portfolio (MW)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	885	**885**
Arizona	-	-	-	-	290	-	-	1,100	**1,390**
British Columbia	50	2	-	-	-	-	-	-	**52**
Carrizo South	-	-	-	-	900	-	-	-	**900**
Colorado	-	-	-	-	-	-	-	1,371	**1,371**
Distributed Solar - Other	-	-	-	-	-	344	-	-	**344**
Distributed Solar - PG&E	-	-	-	-	-	790	-	-	**790**
Distributed Solar - SCE	-	-	-	-	-	895	-	-	**895**
Distributed Solar - SDGE	-	-	-	-	-	127	-	-	**127**
Imperial	-	-	-	-	-	-	-	-	**-**
Kramer	-	-	-	-	-	-	62	-	**62**
Montana	-	-	-	-	-	-	-	300	**300**
Mountain Pass	-	-	-	-	-	-	-	-	**-**
Nevada C	-	-	96	3	50	-	400	-	**549**
New Mexico	-	58	20	-	-	-	-	870	**947**
NonCREZ	163	105	-	-	50	-	-	611	**930**
Northwest	-	44	-	128	-	-	-	2,188	**2,360**
Palm Springs	-	-	-	-	-	-	-	178	**178**
Pisgah	-	-	-	-	275	-	-	-	**275**
Remote DG (Brownfield) - Other	-	-	-	-	-	31	-	-	**31**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	100	-	-	**100**
Remote DG (Brownfield) - SCE	-	-	-	-	-	31	-	-	**31**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	4	-	-	**4**
Riverside East	-	-	-	-	1,008	-	642	-	**1,650**
Round Mountain	-	22	-	-	-	-	-	78	**100**
San Bernardino - Lucerne	7	27	-	-	30	-	-	197	**261**
San Diego South	-	21	-	-	-	-	-	379	**400**
Solano	-	-	-	-	-	-	-	-	**-**
Tehachapi	2	37	-	-	555	-	105	3,452	**4,151**
Utah-Southern Idaho	21	-	42	91	-	-	-	104	**258**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	2	-	-	2	-	-	-	457	**461**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&	-	-	-	-	-	-	-	-	**-**
Total in-State	172	212	-	-	2,818	2,322	809	4,895	**11,228**
Total Out-of-State	73	103	158	223	340	-	400	7,275	**8,573**
Total	245	315	158	223	3,158	2,322	1,209	12,171	**19,802**

Table 4.1-8 Time-constrained portfolio (GWh/yr)

	Time constrained portfolio (GWh/year)								
Zone	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Scale Solar PV	Solar Thermal	Wind	Total
Alberta	-	-	-	-	-	-	-	2,422	**2,422**
Arizona	-	-	-	-	737	-	-	2,711	**3,448**
British Columbia	372	12	-	-	-	-	-	-	**384**
Carrizo South	-	-	-	-	1,959	-	-	-	**1,959**
Colorado	-	-	-	-	-	-	-	3,767	**3,767**
Distributed Solar - Other	-	-	-	-	-	650	-	-	**650**
Distributed Solar - PG&E	-	-	-	-	-	1,546	-	-	**1,546**
Distributed Solar - SCE	-	-	-	-	-	1,771	-	-	**1,771**
Distributed Solar - SDGE	-	-	-	-	-	249	-	-	**249**
Imperial	-	-	-	-	-	-	-	-	**-**
Kramer	-	-	-	-	-	-	145	-	**145**
Montana	-	-	-	-	-	-	-	994	**994**
Mountain Pass	-	-	-	-	-	-	-	-	**-**
Nevada C	-	-	673	10	127	-	935	-	**1,745**
New Mexico	-	418	156	-	-	-	-	2,461	**3,034**
NonCREZ	1,143	782	-	-	117	-	-	1,827	**3,869**
Northwest	-	328	-	383	-	-	-	5,598	**6,309**
Palm Springs	-	-	-	-	-	-	-	532	**532**
Pisgah	-	-	-	-	643	-	-	-	**643**
Remote DG (Brownfield) - Other	-	-	-	-	-	67	-	-	**67**
Remote DG (Brownfield) - PG&E	-	-	-	-	-	204	-	-	**204**
Remote DG (Brownfield) - SCE	-	-	-	-	-	69	-	-	**69**
Remote DG (Brownfield) - SDGE	-	-	-	-	-	9	-	-	**9**
Riverside East	-	-	-	-	2,392	-	1,623	-	**4,015**
Round Mountain	-	162	-	-	-	-	-	220	**383**
San Bernardino - Lucerne	49	201	-	-	77	-	-	541	**868**
San Diego South	-	156	-	-	-	-	-	1,070	**1,226**
Solano	-	-	-	-	-	-	-	-	**-**
Tehachapi	14	276	-	-	1,173	-	245	9,728	**11,436**
Utah-Southern Idaho	158	-	306	333	-	-	-	263	**1,060**
Westlands	-	-	-	-	-	-	-	-	**-**
Wyoming	16	-	-	11	-	-	-	1,438	**1,465**
Remote DG (Greenfield) - PG&E	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SCE	-	-	-	-	-	-	-	-	**-**
Remote DG (Greenfield) - SDG&	-	-	-	-	-	-	-	-	**-**
Total in-State	1,206	1,577	-	-	6,362	4,565	2,013	13,918	**29,641**
Total Out-of-State	546	757	1,135	738	864	-	935	19,654	**24,628**
Total	1,752	2,334	1,135	738	7,226	4,565	2,948	33,571	**54,269**

4.1.2 Comparison of All Portfolios

The installed capacity by location of four portfolios is compared side-by-side in the following table.

Table 4.1-9 Comparison of portfolios by CREZ (MW)

	Resources Selected by Portfolio (MW)			
Zone	Trajectory	Environmentally Constrained	Time Constrained	Base
Tehachapi	4,445	3,491	4,150	3,489
Imperial	1,202	347	-	1,693
Northwest	2,359	838	2,359	711
Pisgah	1,775	275	275	275
NonCREZ	924	449	930	652
Solano	1,129	300	-	535
Riverside East	1,192	1,192	1,650	1,192
Alberta	886	450	886	450
Mountain Pass	888	-	-	523
Carrizo South	900	900	900	900
Utah-Southern Idaho	258	258	258	258
San Diego South	400	400	400	699
Colorado	420	-	1,371	223
Nevada C	450	549	549	450
Distributed Solar - PG&E	500	1,757	790	773
Montana	300	300	300	300
Distributed Solar - SCE	500	2,345	895	750
Arizona	290	290	1,390	290
Wyoming	96	4	461	412
New Mexico	32	78	947	947
Round Mountain	78	100	100	100
Palm Springs	77	178	178	178
San Bernardino - Lucerne	49	140	261	261
Kramer	62	62	62	362
Distributed Solar - SDGE	52	397	127	78
British Columbia	2	52	52	50
Remote DG (Brownfield) - SDGE	-	78	4	9
Remote DG (Brownfield) - PG&E	-	1,842	100	206
Remote DG (Brownfield) - SCE	-	564	31	63
Distributed Solar - Other	-	1,522	344	-
Westlands	-	800	-	-
Remote DG (Brownfield) - Other	-	571	31	-
Remote DG (Greenfield) - PG&E	-	-	-	412
Remote DG (Greenfield) - SCE	-	-	-	126
Remote DG (Greenfield) - SDG&E	-	-	-	17
Total In-State	14,173	17,711	11,228	13,295
Total Out-of-State	5,093	2,818	8,574	4,091
Total	**19,266**	**20,530**	**19,802**	**17,386**

The energy per year by location of four portfolios is compared in the following table.

Table 4.1-10 Comparison of portfolios by CREZ (GWh/yr)

Zone	Resources Selected by Portfolio (GWh/yr)			
	Trajectory	Environmentally Constrained	Time Constrained	Base
Tehachapi	11,465	10,019	11,437	10,005
Imperial	6,193	2,092	-	10,502
Northwest	6,044	2,676	6,308	2,293
Pisgah	4,169	643	643	643
NonCREZ	3,471	3,016	3,869	2,708
Solano	3,473	860	-	1,757
Riverside East	2,906	2,906	4,015	2,906
Alberta	2,422	1,230	2,422	1,230
Mountain Pass	2,178	-	-	1,264
Carrizo South	1,960	1,959	1,959	1,960
Utah-Southern Idaho	1,379	1,446	1,060	1,417
San Diego South	1,227	1,227	1,227	2,096
Colorado	1,169	-	3,767	621
Nevada C	1,062	1,745	1,745	1,062
Distributed Solar - PG&E	1,015	3,313	1,546	1,566
Montana	994	994	994	994
Distributed Solar - SCE	991	4,658	1,771	1,503
Arizona	737	737	3,448	737
Wyoming	317	27	1,465	1,306
New Mexico	238	573	3,034	2,927
Round Mountain	221	383	383	374
Palm Springs	217	532	532	532
San Bernardino - Lucerne	168	845	868	753
Kramer	145	145	145	847
Distributed Solar - SDGE	99	798	249	161
British Columbia	12	384	384	372
Remote DG (Brownfield) - SDGE	-	171	9	19
Remote DG (Brownfield) - PG&E	-	3,740	204	419
Remote DG (Brownfield) - SCE	-	1,258	69	141
Distributed Solar - Other	-	2,890	650	-
Westlands	-	1,781	-	-
Remote DG (Brownfield) - Other	-	1,222	67	-
Remote DG (Greenfield) - PG&E	-	-	-	837
Remote DG (Greenfield) - SCE	-	-	-	282
Remote DG (Greenfield) - SDG&E	-	-	-	38
Total In-State	39,896	44,458	29,642	41,311
Total Out-of-State	14,372	9,811	24,627	12,959
Total	**54,269**	**54,269**	**54,269**	**54,269**

4.1.3 Renewable Generation in Portfolios Breakdown by Area

This section's tables show the renewable generation installed capacity in four portfolios in the ISO-controlled and non ISO-controlled areas, including out of state.

Table 4.1-11 PG&E renewable generation capacity in portfolios (MW)

Zone	Base portfolio	Env.	Traj.	Time
Carrizo South	900	900	900	900
Round Mountain	100	100	78	100
Solano	535	300	1,129	-
Westlands	-	800	-	-
NonCREZ - PG&E - Humboldt	69	11	11	217
NonCREZ - PG&E - North Valley	-	65	-	-
NonCREZ - PG&E - North Coast	282	63	-	262
NonCREZ - PG&E - Los Padres	77	-	-	77
NonCREZ - PG&E - Stockton	45	190	190	190
NonCREZ - PG&E - Greater Fresno	101	101	334	101
PG&E DG	1,392	3,842	500	922
Humboldt DG	16	56	2	5
North Valley DG	99	362	-	21
North Coast DG	53	187	5	14
Greater Bay Area DG	101	892	43	269
Central Valley DG	328	785	80	122
Central Coast/Los Padres DG	163	299	24	84
Greater Fresno DG	632	1,262	346	407
PG&E Total	**3,501**	**6,372**	**3,142**	**2,768**

Table 4.1-12 SCE renewable generation capacity in portfolios (MW)

Zone	Base portfolio	Env.	Traj.	Time
Kramer	362	62	62	62
Mountain Pass	523	-	888	-
Palm Springs	178	178	77	178
Pisgah	275	275	1,775	275
Riverside East	1,192	1,192	1,562	1,650
San Bernardino - Lucerne	261	140	49	261
Tehachapi	3,489	3,491	4,446	4,151
NonCREZ - SCE - Northern	33	12	12	34
NonCREZ - SCE - Western LA	-	2	2	2
SCE DG	939	3,199	500	926
Northern DG	169	695	45	154
North of Lugo DG	133	267	100	100
East of Lugo DG	-	20	-	-
Eastern DG	58	271	-	20
Western LA DG	388	1,243	275	466
Eastern LA DG	191	704	80	185
SCE Total	**7,252**	**8,551**	**9,373**	**7,538**

Table 4.1-13 SDGE renewable generation capacity in portfolios (MW)

Zone	Base portfolio	Env.	Traj.	Time
Imperial - SDGE	404	400	535	-
San Diego South	699	108	400	400
NonCREZ - SDGE	-	6	6	3
SDGE DG	104	402	52	81
SDGE Total	**1,208**	**916**	**993**	**484**

Table 4.1-14 Non ISO BAA renewable generation capacity in portfolios (MW)

Zone	Base portfolio	Env.	Traj.	Time
Imperial - IID	1,289	239	667	-
Alberta	450	450	886	885
Arizona	290	290	290	1,390
British Columbia	50	52	2	52
Colorado	223	-	420	1,371
Montana	300	300	300	300
Nevada C	450	549	450	549
New Mexico	947	78	32	947
Northwest	711	839	2,360	2,360
Utah-Southern Idaho	258	258	258	258
Wyoming	412	4	96	461
NonCREZ	45	-	-	45
DG not in ISO's BAA	-	1,633	-	394
North California DG		1,006		218
South California DG		627		176
Non ISO BAA Total	**5,425**	**4,691**	**5,760**	**9,012**

4.2 Assessment Methods for Policy-Driven Transmission Planning

4.2.1 Power Flow and Stability Assessment

NERC/WECC reliability standards and ISO Planning Standards were followed in the policy-driven transmission planning study. The description of these standards and criteria is provided in Section 2. All required assessments, including power flow contingency analysis, post transient voltage stability analysis, and transient stability analysis, were performed in the policy-driven transmission planning study. The contingencies that have been used in the ISO annual reliability assessment for NERC compliance were revised as needed to reflect the network topology changes and were simulated in the policy-driven transmission planning assessments.

Generally, category C3 overlapping contingencies (e.g., N-1 followed by system adjustments and then another N-1) were not assessed in this policy-driven transmission planning assessment. In all cases, the curtailment of renewable generation following the first contingency can mitigate the impact of renewable generation flow prior to the second contingency. Given the high availability of transmission equipment, the amount of renewable energy expected to be curtailed following transmission outages is anticipated to be minimal.

Overlapping contingencies that could reasonably be expected to result in an excessive amount of renewable generation curtailment were assessed. Outages that potentially impact system-wide stability were simulated and investigated extensively. The existing SPS were evaluated using the base cases to ensure that they do not need to be redesigned. The assessments that have been performed include but not limited to post transient voltage stability and reactive margin analyses, and time-domain transient simulations.

Mitigation plans have been developed for the system limit violations identified in the studies, and the plans were investigated to verify their effectiveness. Multiple alternatives were compared in order to identify the preferred mitigations. If the criteria concern was identified in the ISO Annual Reliability Assessment for NERC compliance but was aggravated by the renewable generation, then the preliminary reliability mitigation was tested to determine if it mitigated the more severe problem created by the renewable generation. Other alternatives were also considered. The mitigation plan recommendation, which may have been the originally identified reliability mitigation or may have been a different alternative, was then included as part of the comprehensive plan.

4.2.2 Deliverability Assessment

Deliverability of the renewable generators studied in the RPS portfolios is assessed following the ISO Generator Deliverability Assessment Methodology. Necessary transmission upgrades were proposed in order to make all renewable generation in the portfolios deliverable. If there is any identified upgrade in the deliverability assessment in the RPS comprehensive transmission planning study, it is included in the final mitigation plans.

The details of the deliverability assessment are discussed in Section 4.10.

4.2.3 Production Cost Simulation

Production cost simulations have been performed for all four renewable portfolios. The ISO unified economic assessment database, which is based on the TEPPC Economic Assessment database, is used as the starting database. The new renewable portfolios were modeled on top of the starting database, and the load was modified to reflect the 2021 CEC load forecast as well. ABB GridView was used to perform the production cost simulations in the policy-driven transmission planning study.

The production cost simulation results were used to identify the generation dispatch and path flow patterns in the 2021 study year after the RPS renewable portfolios were modeled in the system. The selected patterns were used as reference in power flow and stability base case development. The production cost simulation results were also used to analyze the utilization of the transmission system, particularly the major import paths and transmission upgrades.

The details of production cost simulation are discussed in Chapter 5

4.3 Base Case Assumptions

4.3.1 Starting Base Cases Comparison of All portfolios

The peak and off-peak base cases for 2021 in the ISO annual reliability assessment for NERC compliance were used as the starting points of the base case development for the RPS policy-driven transmission planning study. In the ISO annual reliability assessments for NERC compliance, different peak and off-peak base cases were developed for each participating transmission owner (PTO) area, although they were developed from the same WECC seed base cases. In the RPS policy-driven transmission planning, the ISO developed the consolidated base cases for the entire ISO-controlled grid by merging the base cases for different PTO areas.

4.3.2 Load Assumptions

In accordance with the ISO Planning Standards for studies that address regional transmission facilities, such as the design of major interties, a 1 in 5-year extreme weather load level was assumed. An analysis of RPS portfolios for purposes of identifying policy driven transmission needs is a regional transmission analysis. Therefore, the 1-in-5 coincident peak load has been used for the policy-driven transmission planning study. The CEC load forecast posted in December 2009 was used. A typical off-peak period load level on the ISO system is approximately 50 percent of peak load. Therefore, the load level that is 50 percent of the 1-in-5 peak load is selected as the reference of the off-peak load condition (refer to table 4.3-1).

Table 4.3-1 Load condition by areas

Planning Area	1-in-5 coincident peak load (MW)
PG&E	33,269
SCE	28,535
SDG&E	5,488

4.3.3 Conventional Resource Assumptions

The following new conventional generation resources were modeled in the policy-driven planning power flow base cases:

- Marsh Landing (760 MW)
- Russell City Energy Center (600 MW)
- Oakley Generating Station (624 MW)
- Lodi Energy Center (280 MW)
- GWF Tracy Combined Cycle (145 MW)
- Los Esteros Combined Cycle (140 MW)
- Mariposa Energy Project (184 MW)
- Walnut Creek Energy Center (500 MW)
- Canyon Power Plant (200 MW)

- NRG El Segundo Repowering Project (570 MW)
- Sentinel Peaker Project (850 MW).

Resources were not modeled in the base cases if retirement has been officially announced. The once-through cooling units were modeled in the base cases.

4.3.4 Transmission Assumptions

Similar to the ISO's annual reliability assessments for NERC compliance, all transmission projects approved by CPUC and the ISO were modeled in the base cases.

The RPS portfolios and generator interconnection studies have considerable overlap in terms of location and generation technology . It is reasonable to assume that transmission upgrades that are in an executed LGIA would be needed to interconnect and deliver renewable generation in the RPS portfolios if the renewable generation capacity, technology and location in the portfolios correspond to that in generator interconnection studies. Therefore, some transmission upgrades in executed LGIAs were modeled in the policy-driven planning base cases based on the comparison of portfolios discussed in Section 4.1 and previous generator interconnection studies results.

Tables 4.3-2 and 4.3-3 summarize the transmission projects with CPUC approval or in executed LGIAs that are modeled in the policy-driven transmission planning base cases. The Pisgah-Lugo 500 kV transmission project and conversion of Pisgah 230 kV to 500 kV were initially modeled in the base case. However, these transmission projects were determined to not be needed in the deliverability sensitivity study of the base portfolio and therefore are not listed in the table below. These results are described in the Deliverability Assessment Results section later in this chapter.

Table 4.3-2 Transmission projects approved or in executed LGIA that are modeled in the policy-driven planning base cases

Transmission Upgrade	Approval Status	
	ISO	CPUC
Carrizo-Midway	LGIA	pending
Sunrise Powerlink	Approved	Approved
Eldorado-Ivanpah	LGIA	Approved
Valley-Colorado River	Approved	Approved
West of Devers Upgrade	LGIA	pending
Tehachapi	Approved	Approved
Coolwater-Lugo 230 kV line	LGIA	pending
South of Contra Costa recondutoring	LGIA	pending
Borden-Gregg 230 kV line reconductoring	LGIA	pending
Mirage-Devers 230 kV lines upgrade	Approved	pending
Whirlwind #2 and #3 transformers	LGIA	Not needed
Imperial #3 transformer	LGIA	Not needed
Humboldt 60 kV upgrades	LGIA	pending

Table 4.3-3 Other transmission projects modeled in the policy-driven planning base cases

Transmission Upgrade	Area	Comments
Coachella-Ramon-Mirage 230 kV lines upgrade	IID	Identified by IID as needed to interconnect renewable generation in IID system in RPS portfolios
IID Imperial Valley-El Centro and Dixie 230 kV line	IID	Identified by IID as needed to interconnect renewable generation in IID system in RPS portfolios

Some new substations are needed for the transmission projects listed in Table 4.3-2 and for interconnecting new generation projects that have executed LGIA. These substations are listed in Table 4.3-4.

Table 4.3-4 New substations modeled in the policy-driven planning base cases

Substation	Associated transmission lines
New ECO 500 kV	Imperial Valley-Miguel 500 kV loop-in
New Red Bluff 500 kV	Colorado River-Dever 500 kV lines loop-in
New Jasper 230 kV	Coolwater-Lugo 230 kV loop-in
Conversion of Ivanpah 115 kV to Ivanpah 230 kV	El Dorado-Ivanpah 230 kV
New Carrizo 230 kV	Morro Bay-Midway 230 kV loop-in

The new transmission facilities listed in table 4.3-2 are shown in figure 4.3-1.

Figure 4.3-1 New transmission facilities allowing delivery of renewable generation

4.4 Power Flow and Stability Base Case Development

4.4.1 Modeling Renewable Portfolio

4.4.1.1 Power Flow Model and Reactive Power Capability

As discussed in Section 4.2, the CPUC's renewable portfolios have been used to represent RPS portfolios in the policy-driven transmission planning study. In these portfolios, CPUC has assigned renewable resources by technology to geographic areas, including CREZs and locations of non-CREZs, and specific substations for some distributed generation resources. Based on the general location information included in the CPUC's portfolios, the ISO modeled renewable resources in the power flow model based on information from generator interconnection studies performed by the ISO and utilities. Note that the objective of this process of modeling generation projects is to streamline transmission analysis of the renewable portfolios, and is not meant to endorse any particular generation project.

If modeling data from ISO or PTO generation interconnection studies were used, it included the reactive power capability (the minimum and the maximum reactive power output). If modeling data came from other sources, an equivalent model is used that matches the capacity as listed in the portfolios. When an equivalent model is used, it was assumed that the generator can regulate bus voltage within a power factor range of 0.95 lagging to leading if it was a wind turbine generator or solar PV generator rather than a distributed generator. For the renewable generation that use other technology such as solar thermal, geothermal biomass and biogas, typical data are used in the equivalent model with a power factor range of 0.90 lagging and 0.95 leading.

Each of the studied portfolios included distributed generation. They were modeled as an equivalent generator at the point of interconnection with unity power factor.

4.4.1.2 Dynamic Modeling of Renewable Generators

Similar to the power flow model, if the modeling data came from the ISO or PTO generation interconnection studies, then the dynamic models from the generation interconnection study, if available, were also used.

If dynamic models were not available, the generic models were used. For geothermal, biomass, biogas and solar thermal projects, the dynamic models of similar existing units in the system were used, including generator, exciter, power system stabilizer PSS and governor models. For wind turbine generators and PV solar generators, GE Positive Sequence Load Flow Software PSLF generic models are used. It is assumed in this study that the Type 3 wind turbine generator model for doubly fed induction generator (DFIG) were used for wind generators. It was also assumed that the Type 4 inverter model used for a machine with full converter interface and variable speed was used for PV solar generators. For both Type 3 and Type 4 dynamic models, the control parameters are set such that the generators have adequate low voltage ride through (LVRT) and low frequency ride through (LFRT) capability.

4.4.2 Generation Dispatch and Path Flow in Base Cases

Power flow and stability studies are normally based on the assumptions of generation dispatch that are agreed upon using historical data and engineering judgment. As the system approaches the RPS, generation dispatch and power flow patterns will substantially change. The historical generation dispatch and path flows are not expected to be representative of future system conditions.

Production cost simulation software was used to predict unit commitment and economic dispatch on an hourly basis for the study year. The production cost simulation results were used as reference data to predict future dispatch and flow patterns.

Generally, certain hours that represent stressed patterns of path flows in the 2021 study year were selected from the production cost simulation results, and the objective was to study a reasonable upper bound on stressed system conditions. Because the renewable portfolios in the 2010/2011 transmission planning cycle were similar to the portfolios studied in this cycle, path flow information from the production simulation runs performed for the 2010/2011 transmission planning cycle were also considered. The following three critical factors were considered in the selection of the stressed patterns:

- renewable generation output;
- power flow on the major transfer paths in California; and
- load level.

For example, one set of hours that was selected for bounding purposes is a time frame during which there were near maximum renewable generation output and near maximum transfers across major ISO transmission paths during peak hours or off-peak hours. Similarly, other hours were selected to study different renewable and path flow patterns stressing particular paths and local areas.

It was recognized that modeling network constraints had significant impacts on the production cost simulation results. The simplest constraints are the thermal branch ratings under normal and contingency conditions. It was not practical to model all contingencies and branches in the simulation because of computational limitations. Given this gap between the simulation and the power flow and stability assessments, as well as the production cost simulation is based on DC power flow model, the dispatch of conventional thermal units in power flow and stability assessments generally followed variable cost to determine the order of dispatch, but out of order dispatch may have been used to mitigate local constraints.

In the dispatch of conventional thermal units, OTC units are not targeted to be turned off or decreased before other units. However, OTC was decreased first if two units had the same variable cost and could meet the same local reliability needs.

4.5 Base Cases and Scenarios for Power Flow and Stability Assessments

Multiple scenarios were studied for each renewable portfolios in order to investigate the transmission need under a range of expected conditions. Both peak and off-peak conditions were assessed. The renewable dispatch and path flow patterns studied for each portfolio are shown in Table 4.5-1. Because of the objective to study stressed cases with high renewable production levels, the off-peak scenarios studied represent low load, weekend daytime hours with solar production.

Table 4.5-1 Renewable dispatch and path flow patterns by portfolios

Portfolio and scenario	New Renewable output (MW)	Path 49 (MW)	Path 26 (MW)	Path15 (MW)	Path 66 (MW)	Path 65 (MW)
Base portfolio Peak load	10,957	5,513	2,423	1,213	4,016	1,600
Base portfolio Off-peak load	11,475	2,831	-1,752	5,100	32	0
Environmentally constrained portfolio Peak load	9,748	5,497	3,876	-183	4,029	1,300
Environmentally constrained portfolio Off-peak load	17,650	2,256	-1,763	5,114	-1,091	0
Trajectory portfolio Peak load	8,652	5,544	2,707	1,210	4,100	1,600
Trajectory portfolio Off-peak load	13,737	2,257	-1,818	5,117	2,432	900
Time-constrained portfolio Peak load	7,773	5,508	2,282	1,420	4,005	1,600
Time-constrained portfolio Off-peak load	12,563	2,301	-1,766	5,176	1.4	0

4.6 Production Cost Simulation and Utilization Analysis

To evaluate the utilization of the transmission system for 8,760 hours of the 2021 study year, production cost simulations were performed for all four portfolios, as well as for the CPUC cost-constrained portfolio that was presented at the July 8, 2011 stakeholder meeting. Most transmission lines were monitored in the production cost simulations, but instead of analyzing all transmission lines, two sets of transmission lines or branch groups were analyzed. These were the LGIA lines that were modeled in the base cases but have not yet received CPUC approval and some major transmission paths within or coming into California. The utilization of these transmission lines was expected to vary in different portfolios because the renewable generation distribution and technology were different from one portfolio to another.

4.6.1 Transmission Lines in Executed LGIAs

Coolwater-Lugo 230 kV line

The Coolwater-Lugo 230 kV line mainly serves the renewable generation in the North of Lugo area, which includes several CREZs such as Kramer, Inyokern and Owens Valley. The existing generation in the North of Lugo area, which includes conventional thermal, solar thermal, geothermal and hydro generation, also contributes to the flow on the Coolwater-Lugo 230 kV line. In the renewable portfolios used for the 2011/2012 transmission planning study, only the Kramer CREZ was assumed to have any generation development. Refer to table 4.6-1, figure 4.6-1 and figure 4.6-2.

Table 4.6-1 CREZs mainly served by Coolwater-Lugo 230 kV line

CREZ	CPUC Cost-constrained (MW)	Base (MW)	Env. (MW)	Time (MW)	Traj. (MW)
Kramer	62	332	62	62	62
San Bernardino - Lucerne	261	261	140	261	49
DG in North of LUGO area	133	133	267	100	100

Figure 4.6-1 Power flow duration curves of Coolwater-Lugo

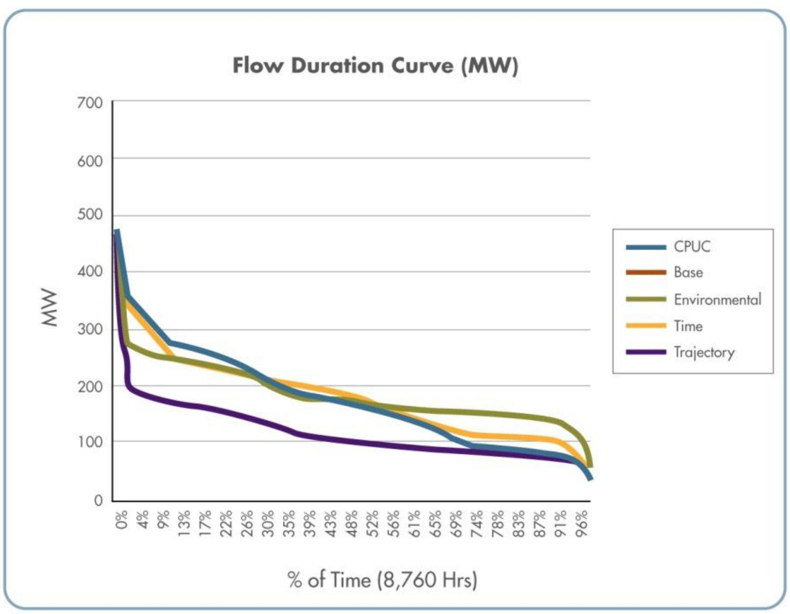
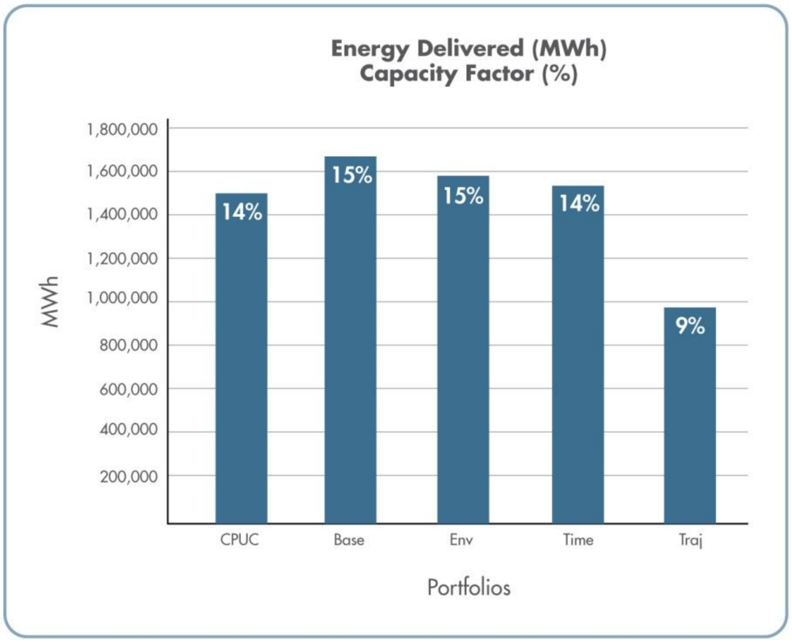


Figure 4.6-2 Delivered energy on Coolwater-Lugo



West of Devers (WOD) 230kV lines

West of Devers branch group, consists of four 230 kV lines going west from Devers Substation and is downstream of Path 42 and Colorado River- Devers 500 kV lines. Renewable generation output from Imperial North and Riverside East, as well as the imports from EOR, flow through the WOD branch group. The high utilization of WOD branch group in the base and CPUC cost-constrained portfolios is mainly due to the high renewable penetration in the IID system and Riverside east, respectively (refer to table 4.6-2, figure 4.6-3 and figure 4.6-4).

Table 4.6-2 CREZs mainly served by WOD 230kV lines

CREZ	CPUC Cost-constrained	Base	Env.	Time	Traj.
Riverside East	**1,192**	**1,192**	**1,192**	**1,650**	**1,192**
Palm Springs	**178**	**178**	**178**	**178**	**77**
DG in Eastern areas	**58**	**58**	**271**	**20**	**0**
Imperial – IID	**1,289**	**1,289**	**239**	**0**	**667**

Figure 4.6-3 Power flow duration curves of West of Devers

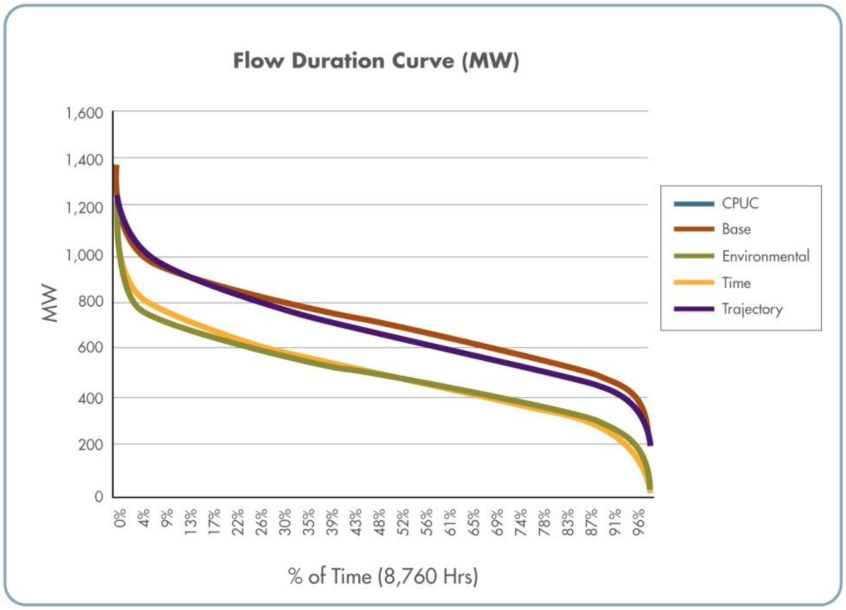
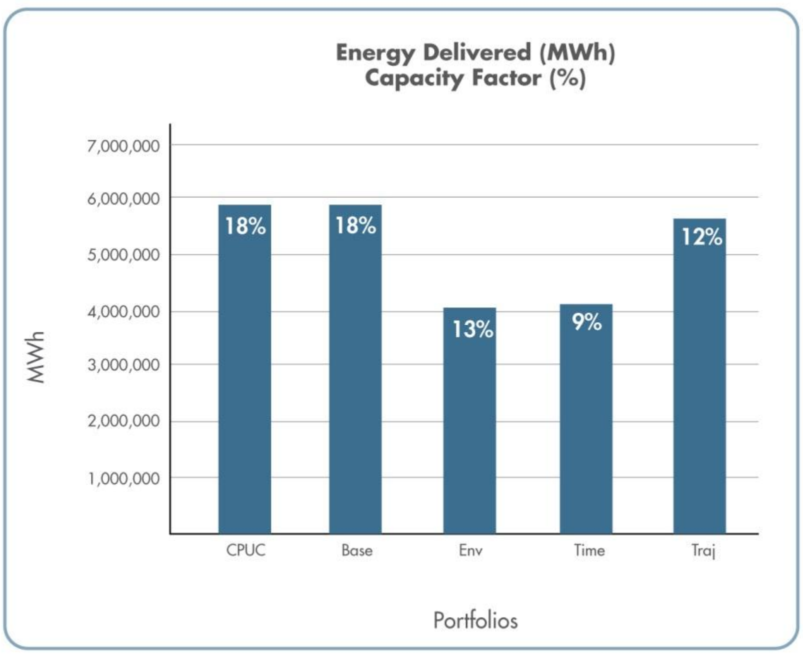


Figure 4.6-4 Delivered Energy on West of Devers



Pisgah-Lugo 500 kV lines

The loop-in of the existing Eldorado-Lugo 500 kV line into the new Pisgah 500 kV Substation and conversion of one of the existing Pisgah-Lugo 230 kV lines to 500 kV create two Pisgah-Lugo 500 kV lines. This upgrade serves renewable interconnections in the Mountain Pass, Pisgah and NV West areas. The East of River flow also has a direct impact on the flow on the Pisgah-Lugo 500 kV lines (refer to table 4.6-3, figure 4.6-5 and figure 4.6-6).

Table 4.6-3 CREZs mainly served by Pisgah-Lugo 500 kV lines

CREZ	CPUC Cost-constrained	Base	Env.	Time	Traj.
Mountain Pass	**523**	**523**	**0**	**0**	**888**
Pisgah	**275**	**275**	**275**	**275**	**1,775**
DG in East of Lugo	**0**	**0**	**20**	**20**	**0**

Figure 4.6-5 Power flow duration curves of Pisgah – Lugo lines

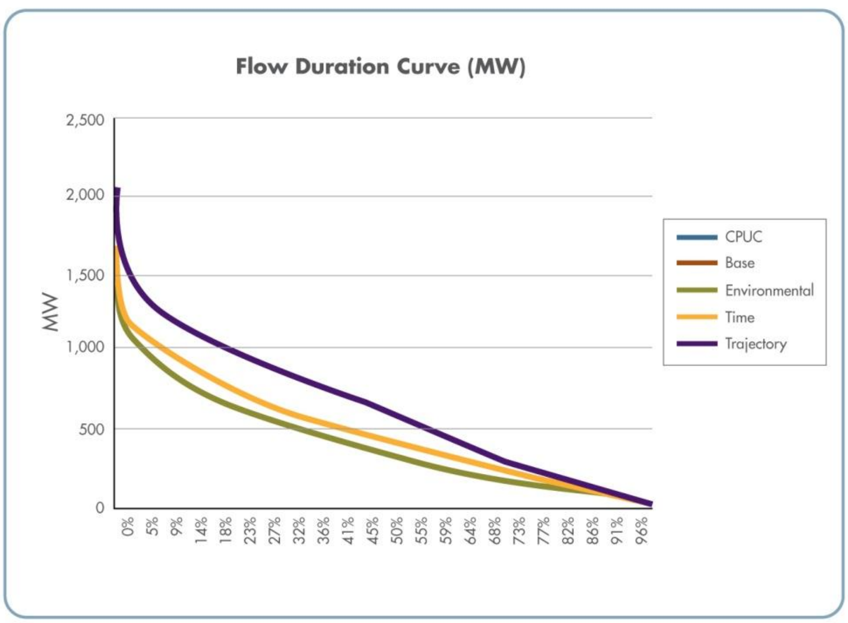
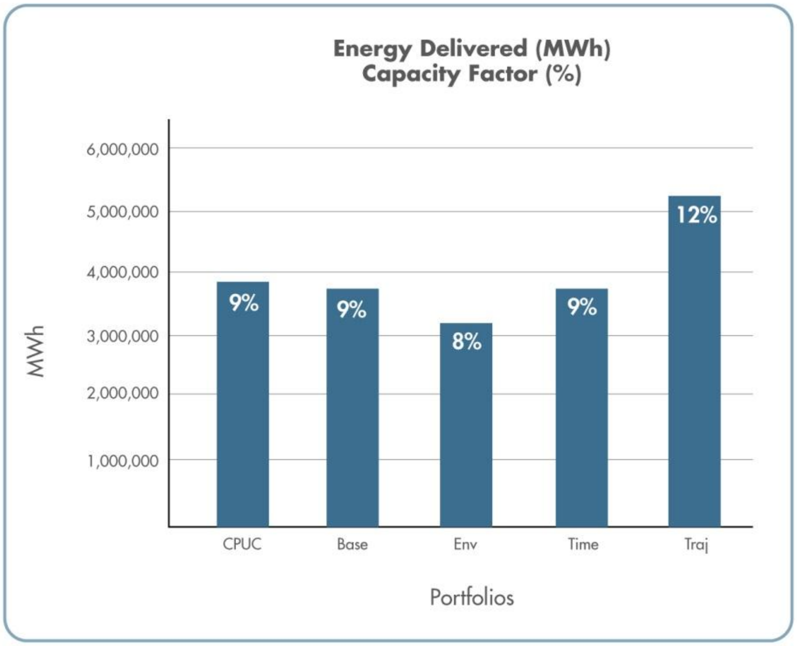


Figure 4.6-6 Delivered Energy on Pisgah-Lugo lines



4.6.2 Selected Transmission Paths

Sunrise + SWPL

The Imperial Valley-Miguel section of SWPL (Southwest Power Link) and Sunrise Powerlink comprise the major transmission path that connects the Imperal Valley and San Diego. There are two 500 kV lines in this path including Imperial Valley-Miguel with loop-in to the new ECO 500 kV substation and Imperial Valley-SunCrest 500 kV lines. Renewable generation at Imperial Valley and San Diego South CREZs and Arizona contributes to the flow on this path.

Figure 4.6-7 Power flow duration curves of Sunrise + SWPL

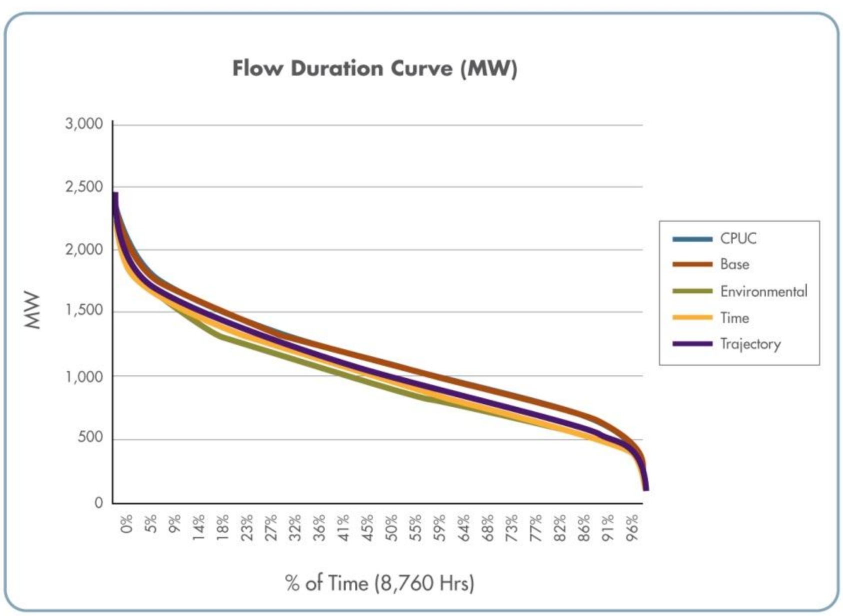
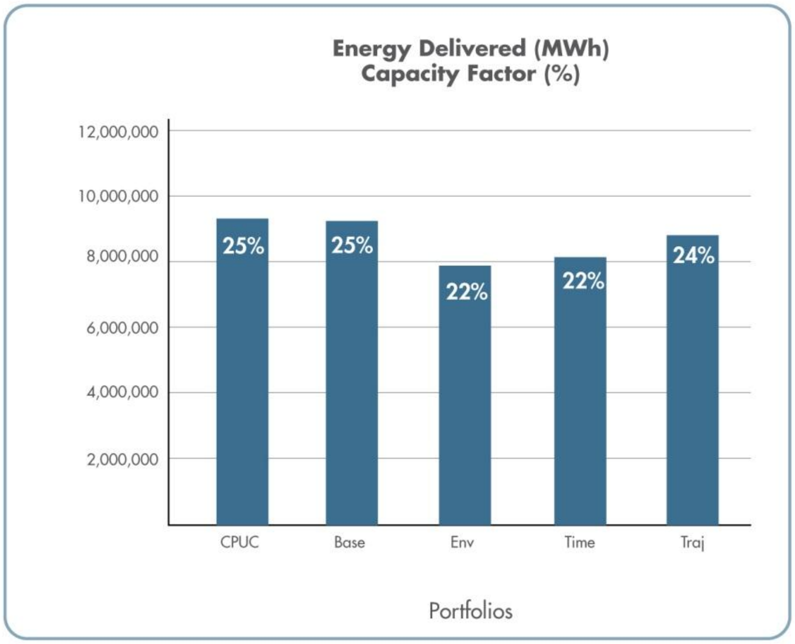


Figure 4.6-8 Delivered Energy on Sunrise + SWPL



West of River (Path 46) and East of River (Path 49)

West of River and East of River are the transmission paths that connect the Southern California system with the transmission systems of states to the east. They are the major importing paths to Southern California, and many renewable resources are located in the areas along these transmission paths. From North to South, the CREZs in which the renewable resources contribute to the flow on West of River and East of River are Pisgah, Mountain Pass, Riverside East, Palm Spring, Imperial Valley, San Diego South and the renewable areas in Nevada, Arizona and other states.

Figure 4.6-9 Power flow duration curves of West of River

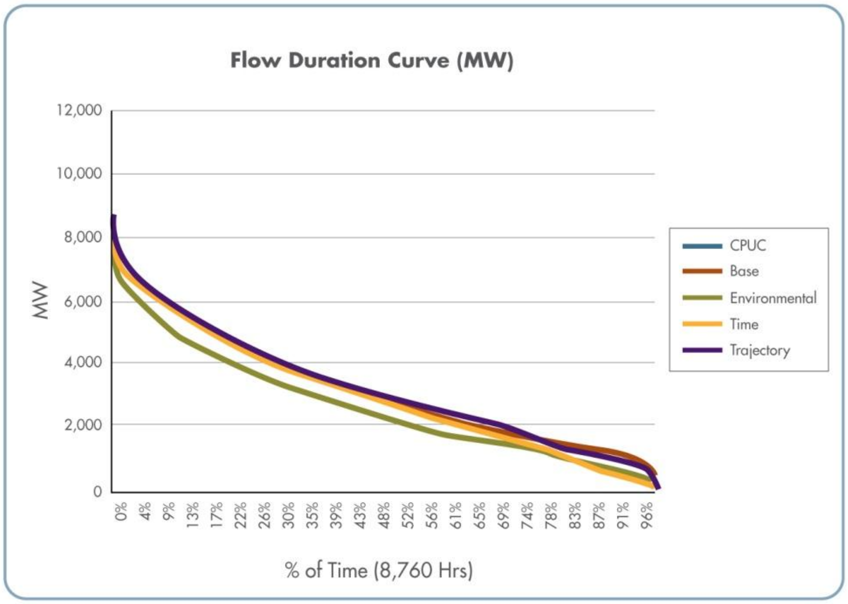


Figure 4.6-10 Delivered Energy on West of River

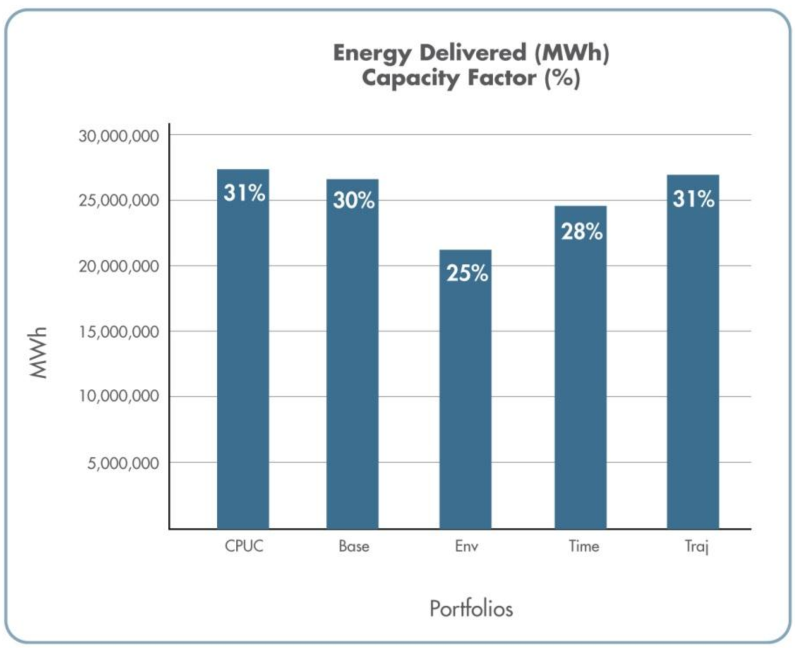


Figure 4.6-11 Power flow duration curves of East of River

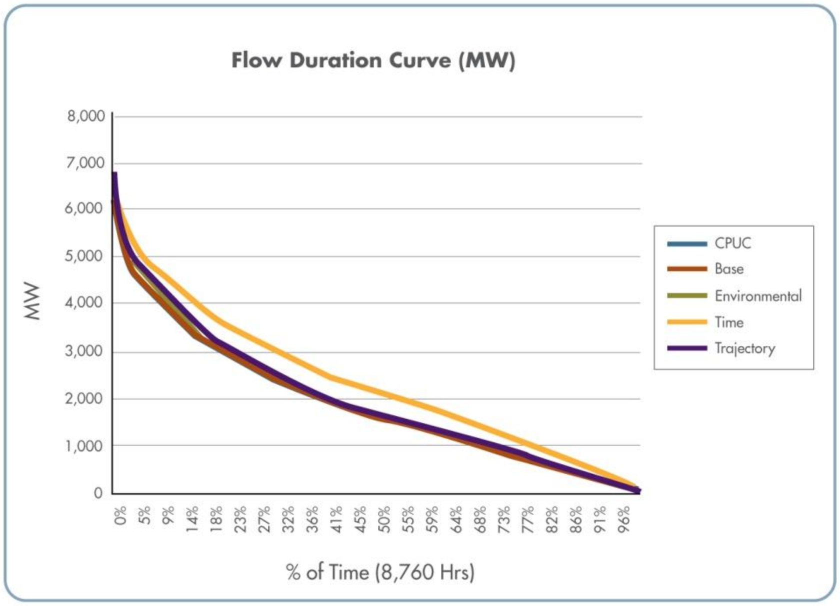
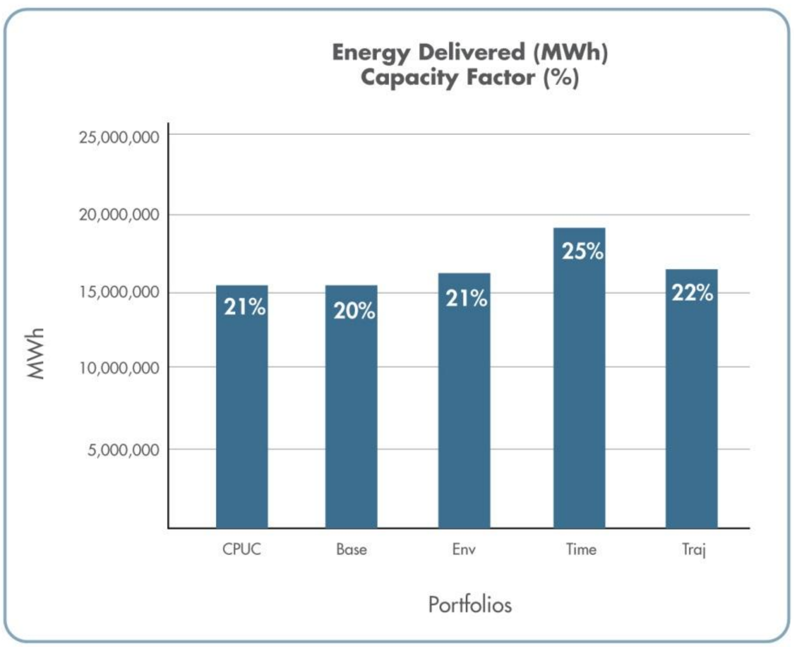


Figure 4.6-12 Delivered energy on East of River



Path 26

Path 26 includes three 500 kV lines between Southern and Northern California. The variation on renewable generation output in Southern and Northern California may affect both magnitude and direction of the power flow on Path 26.

Figure 4.6-13 Power flow duration curves of Path 26

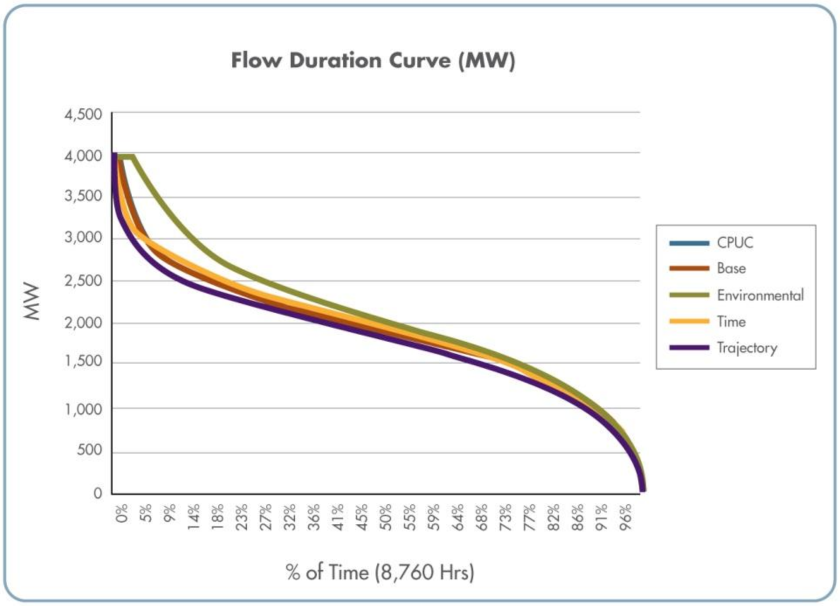
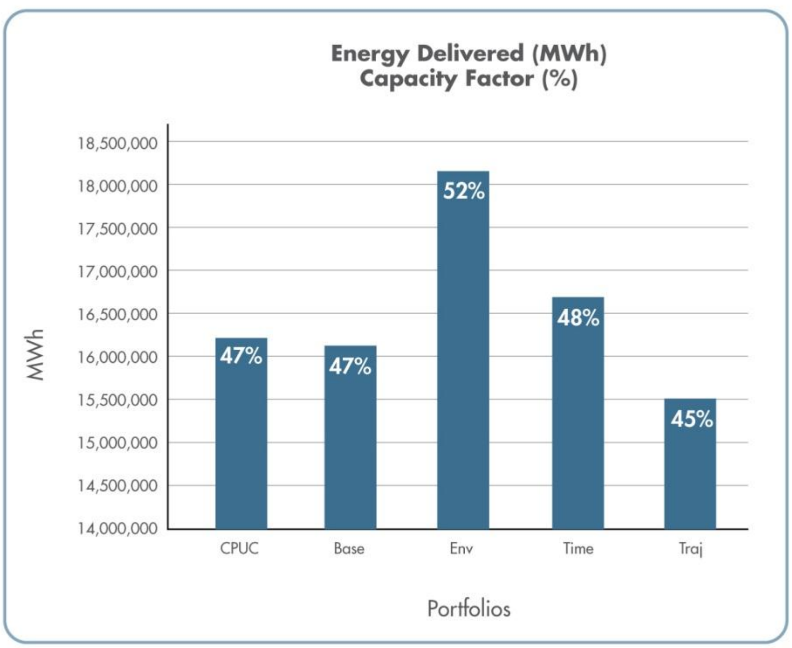


Figure 4.6-14 Delivered energy on Path 26



Path 15

Path 15 includes three 500 kV lines and four 230 kV lines between the South and North PG&E area.

Figure 4.6-15 Power flow duration curves of Path 15

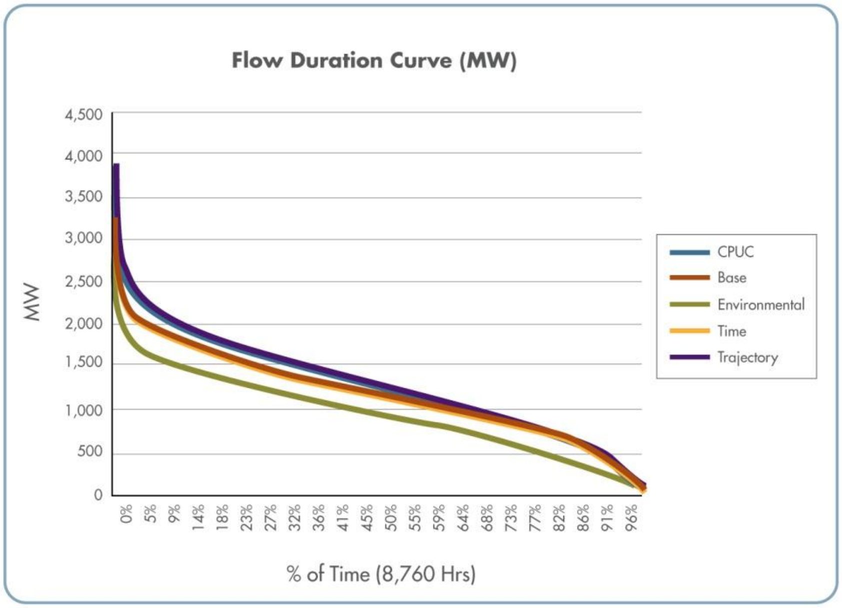
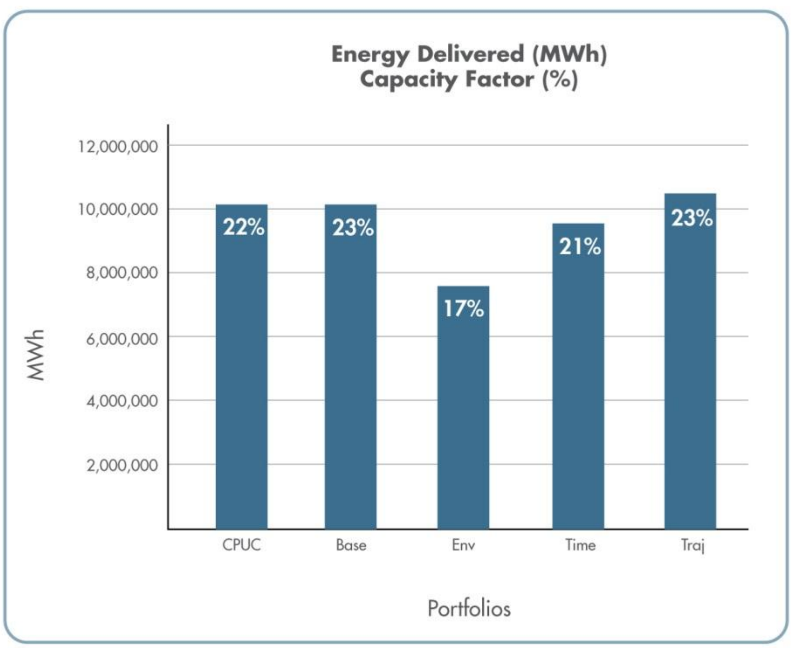


Figure 4.6-16 Delivered Energy on Path 15



COI (Path 66)

COI is the inter-tie between California and the Northwest, consisting of three 500 kV transmission lines.

Figure 4.6-17 Power flow duration curves of COI

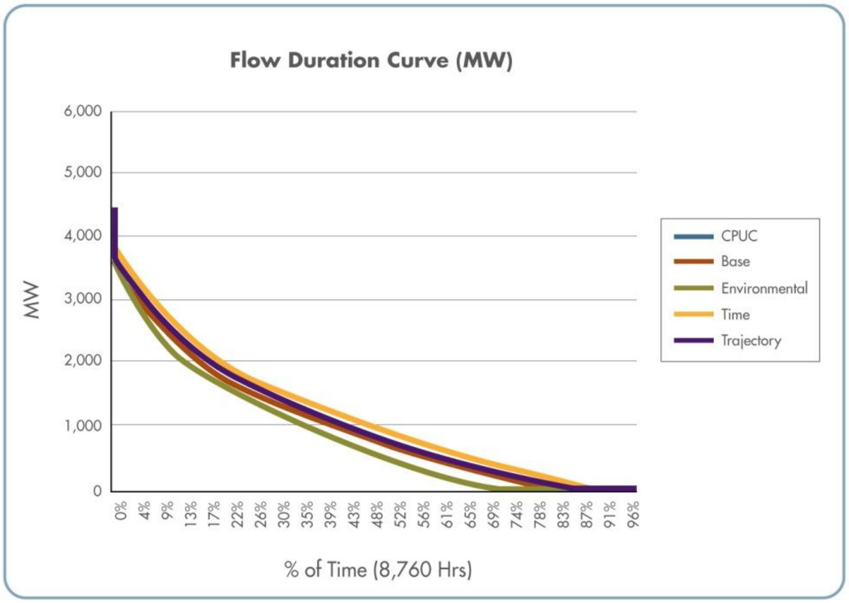
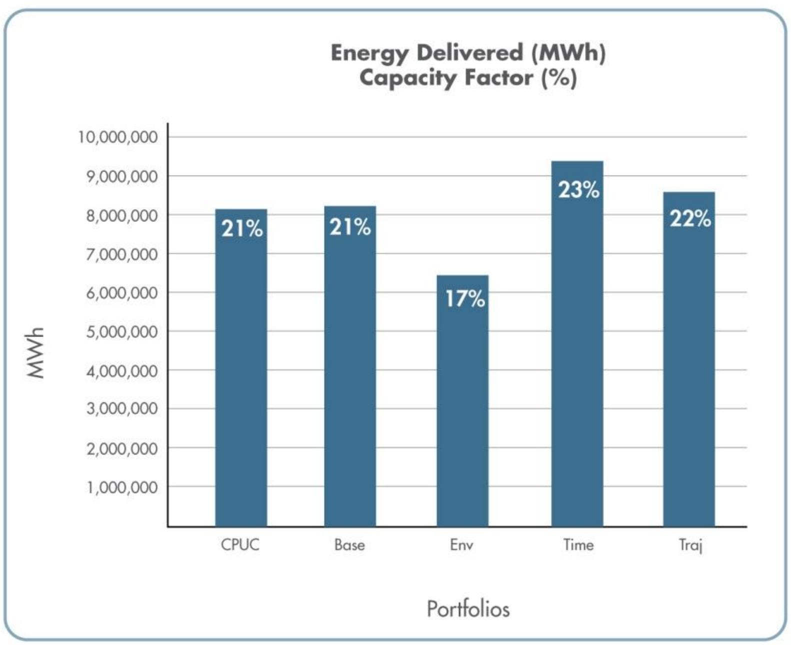


Figure 4.6-18 Delivered energy on COI

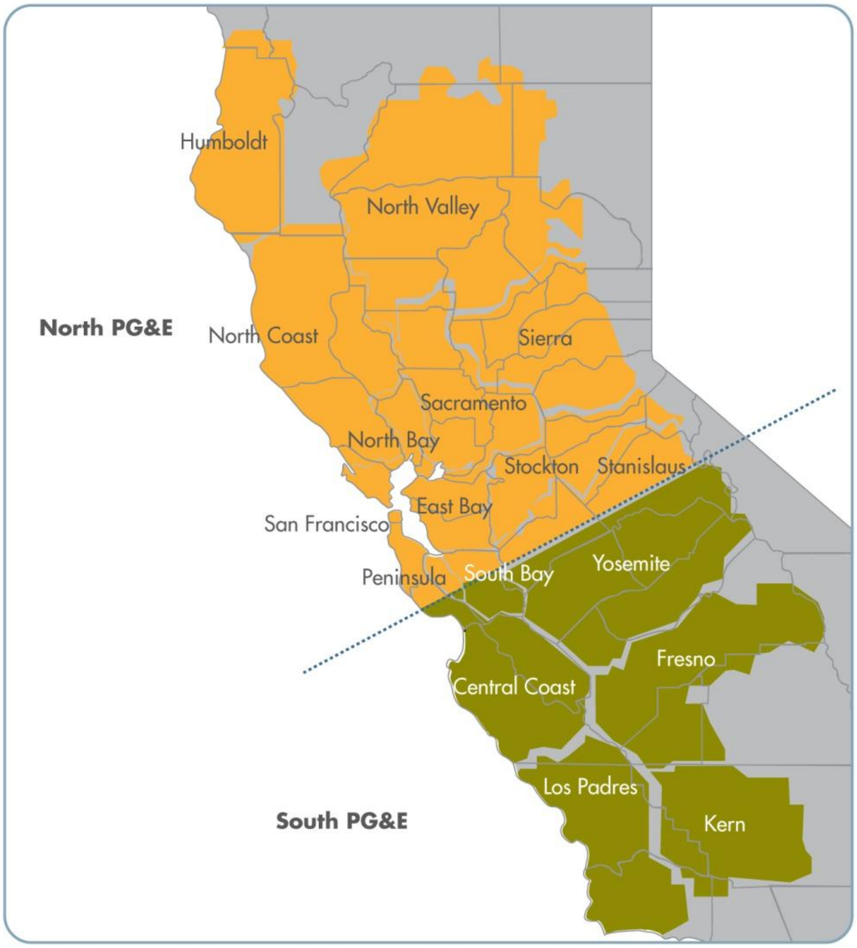


4.7 Policy Driven Assessment Results and Mitigations in PG&E Area

The renewable generation scenarios assessment included the four renewable portfolios evaluations described earlier: base case, trajectory, time-constrained and environmentally constrained. Power flow studies were performed for all credible contingencies in the same areas of the PG&E transmission system as in the reliability studies. Category C3 contingencies, which is an outage of one transmission facility after another non-common-mode facility is already out were not studied because it was assumed that the negative impacts can be mitigated by limiting generation following the first contingency. The assessment results were summarized for North PG&E area and South PG&E area without detailed descriptions of each zone. Post transient and transient stability studies that evaluated all major 500 kV single and double contingencies and two-unit outages of nuclear generators were performed for the PG&E bulk system. The area studies and the bulk system studies included all four portfolios for 2021 peak and off-peak conditions. For the bulk system and the southern areas of PG&E, the off-peak studies included scenarios with one unit at the Helms Pump Storage Power Plant operating in the pumping mode, as well as scenarios with three Helms units in the pumping mode.

The division of the PG&E area into northern and southern regions is shown in Figure 4.7-1.

Figure 4.7-1 Northern and Southern areas of the PG&E system



4.7.1 Northern PG&E Overview

The Northern PG&E area studies included assumptions on the renewable resources summarized in Table 4.7-1.

Table 4.7-1: Renewable resources in North PG&E area modeled to meet the 33 percent RPS net short

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Base	1,637	932	563
Environmental	3,787	2,511	3,186
Trajectory	1,543	540	754
Time-constrained	1,423	824	978

Table 4.7-2 shows how these resources were distributed among the CREZs.

Table 4.7-2 North PG&E Renewable Generation by zones modeled to meet 33 percent RPS net short

Zones	Base portfolio	Environmentally constrained portfolio	Trajectory portfolio	Time-constrained portfolio
Round Mountain	100	100	78	100
Solano	535	300	1,129	-
Non-CREZ: PG&E - Humboldt	69	11	11	217
Non-CREZ: PG&E - North Valley	-	65	-	-
Non-CREZ: PG&E - North Coast	282	63	-	262
Non-CREZ: PG&E - Stockton	45	190	190	190
Humboldt Distributed Generation	16	56	2	5
North Valley Distributed Generation	99	362	-	21
North Coast Distributed Generation	53	187	5	14
Bay Area Distributed Generation	101	892	43	269
Central Valley Distributed Generation	328	785	80	122
Municipal Utilities	9	776	5	224
TOTAL	1,637	3,787	1,543	1,423

Table 4.7-3 New Renewable generation output in North PG&E areas

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Base	1637	932	563
Environmental	3787	2511	3186
Trajectory	1543	540	754
Time Constrained	1423	824	978

PG&E areas included in the North PG&E studies are as follows: Humboldt, North Coast, North Bay, San Francisco, Peninsula, South Bay, East Bay, North Valley, Sacramento, Sierra, Stockton and Stanislaus. These areas were described in detail in Chapter 2; therefore, the following sections include only the study results and mitigations of identified problems.

4.7.1.1 Humboldt Area

The Humboldt area is located in the most Northern part of the PG&E system along the Pacific Coast. The reliability studies described in Chapter 2 assumed that in 2016, a new 50 MW wind generation project will be added in this area. This project is planned to interconnect to the Rio Dell Junction 60 kV Substation. The studies for renewable portfolios assumed 85 MW of renewable generation in Humboldt in the base case, including this wind project, as well as the existing 11 MW Blue Lake biomass project. The environmentally constrained portfolio had 66 MW of renewable generation in the Humboldt area. The trajectory case had 13 MW (only 2 MW in addition to the existing Blue Lake plant), and the time-constrained portfolio had 222 MW.

4.7.1.1.1 Study Results and Discussion

The Humboldt area is located in the most Northern part of the PG&E system along the Pacific Coast. The reliability studies described in Chapter 2 assumed that in 2016, a new 50 MW wind generation project will be added in this area. This project is planned to interconnect to the Rio Dell Junction 60 kV Substation. The studies for renewable portfolios assumed 85 MW of renewable generation in Humboldt in the base case, including this wind project, as well as the existing 11 MW Blue Lake biomass project. The environmentally constrained portfolio had 66 MW of renewable generation in the Humboldt area. The trajectory case had 13 MW (only 2 MW in addition to the existing Blue Lake plant), and the time-constrained portfolio had 222 MW.

Thermal Overloads

Bridgeville-Garberville 60 kV transmission line

The Bridgeville-Fruit Land section of this transmission line was identified with thermal overload under normal conditions with all facilities in service. The same section, as well as the rest of the Bridgeville-Garberville 60 kV line (two other sections: Fruit Land-Fort Seward-Garberville) were overloaded under category B contingency conditions with an outage of the Bridgeville-Cottonwood 115 kV line. These overloads are expected in the environmentally constrained portfolio under peak load conditions. The same transmission line was identified as overloaded in the reliability studies in the 2021 case (see Chapter 2). A transmission project to construct a new 115 kV line from Bridgeville to Garberville was proposed to mitigate both this overload and voltage concerns. With additional renewable generation modeled in the environmentally constrained portfolio, overload on the Bridgeville-Garberville 60 kV line was higher than in the reliability studies. The new Bridgeville-Garberville 115 kV line would mitigate the overload under normal conditions. It would also mitigate category B and C contingency overloads and voltage concerns. If the new transmission line is not constructed, the reconductoring of the overloaded sections would mitigate the overload.

Humboldt-Trinity 115 kV transmission line

Humboldt-Trinity 115 kV transmission line may overload in the time-constrained portfolio with an outage of the Cottonwood-Bridgeville 115 kV transmission line under peak load conditions. Dispatching more generation from the Humboldt Bay units connected to 115 kV will mitigate this overload. Only one out of four Humboldt Bay 115 kV units was modeled as dispatched in this case. If at least two of the Humboldt Bay units are dispatched under peak load conditions, this overload will not be expected. Another alternative is an upgrade of the Humboldt-Trinity 115 kV transmission line.

Trinity-Cottonwood 115 kV transmission line

Trinity-Cottonwood 115 kV transmission line may overload in the environmentally constrained portfolio with an outage of the Humboldt-Bridgeville 115 kV transmission line under peak load conditions. This overload was caused by a renewable generation project modeled at the Trinity 115 kV bus. Installing an SPS to trip this generation will mitigate the overload. Another alternative is an upgrade of the Trinity-Cottonwood 115 kV transmission line.

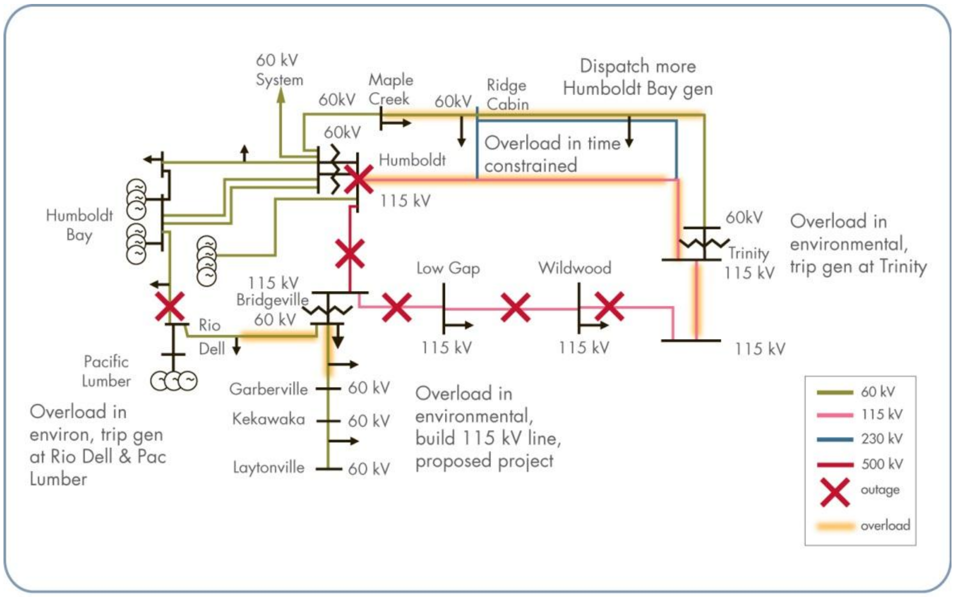
Trinity-Cottonwood 60 kV transmission line

The sections of the Trinity-Cottonwood 60 kV transmission line between Trinity and Maple Creek were identified as overloaded with an outage of the Humboldt 115 kV bus (category C contingency) in the time-constrained portfolio under peak load conditions. This overload was caused by low output of the Humboldt Bay power plant units connected to the 60 kV bus (only one unit out of six was modeled as dispatched). With higher output from the 60 kV units of the Humboldt Bay power plant, the overload would be mitigated. Dispatching at least 42 MW (three generation units) of the Humboldt Bay power plant at 60 kV under peak load conditions would eliminate the overload. Another alternative is an upgrade of the overloaded sections of the Trinity-Cottonwood 60 kV transmission line.

Rio Dell Junction-Bridgeville 60 kV transmission line

Rio Dell Junction-Bridgeville 60 kV transmission line may overload for category B contingencies in the base and environmentally constrained portfolios under peak load conditions and in the base and time-constrained portfolios under off-peak load conditions. Overload of this facility under category B and C contingencies was also observed in the reliability studies described in Chapter 2, and additional renewable generation exacerbates the overload. Installation of an SPS to trip renewable generation connected at the Rio Dell Junction 60 kV Substation was proposed to mitigate the overload in the reliability studies. In the renewable portfolios, new projects connecting to the Rio Dell Substation and/or the existing Pacific Lumber generation will need to be added to the SPS. The Rio Dell Junction-Bridgeville 60 kV line may also overload for a category C contingency (outage of the Humboldt 115 kV bus) in the time-constrained portfolio under peak load conditions. Dispatching three units of the Humboldt Bay power plant connected to 60 kV that was needed to mitigate the overload on the Humboldt-Trinity 60 kV line would also mitigate overload on the Rio Dell Junction-Bridgeville 60 kV line with this outage. Another alternative is an upgrade of the Rio Dell Junction-Bridgeville 60 kV transmission line. The observed thermal overload problems and their solutions are illustrated in Figure 4.7-2

Figure 4.7-2 Humboldt Area Overloads



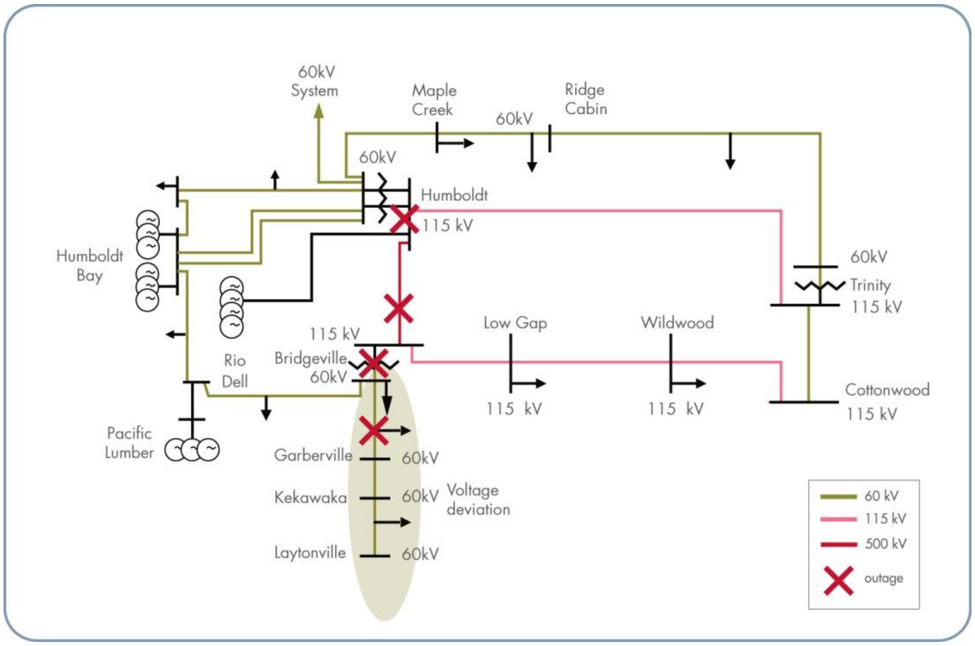
Voltage Issues

Voltage and Voltage Deviation Concerns

No voltage concerns were identified in the Humboldt area for any of the renewable portfolios under peak or off-peak load conditions. Large voltage deviations (down) in the Garberville-Bridgeville-Laytonville 60 kV system were observed with an outage of the Bridgeville 115/60 kV transformer or an outage of the Bridgeville-Garberville 60 kV line in the time-constrained, trajectory and environmentally constrained portfolios under peak load conditions. Bridgeville-Garberville 60 kV line outage may also cause voltage deviations at Garberville and Kekawaka 60 kV buses in the environmentally constrained portfolio under off-peak conditions. The solution is the proposed new Bridgeville-Garberville 115 kV line that is also needed to mitigate thermal overloads. Additional reactive support would also mitigate the voltage deviation concerns, but it would not mitigate thermal overloads.

In the time-constrained portfolio, the studies showed possible voltage collapse with an outage of the Humboldt 115 kV bus. This is because with this outage, all generation from the Humboldt Bay Power plant on the 115 kV bus will be lost. Thus, the only unit modeled as dispatched at the Humboldt Bay Power Plant 60 kV bus was not sufficient to provide an adequate reactive margin. Dispatching more units at the Humboldt Bay 60 kV that was also needed for thermal loading concerns would solve this problem. The observed voltage deviation problems and their solutions are illustrated in Figure 4.7-3.

Figure 4.7-3: Humboldt area voltage deviation concerns



4.7.1.1.2 Conclusions

The studies showed that the existing transmission system in the Humboldt area is adequate to accommodate additional renewable generation assumed to be developed in the four portfolios. No additional transmission upgrades would be necessary. The new Bridgeville-Garberville 115 kV Transmission Line Project proposed in the reliability studies would mitigate thermal and voltage concerns that may be aggravated by additional generation projects. To avoid other thermal overloads, several SPSs to trip new or existing generation projects would be required. It would also be necessary to maintain a certain dispatch level of the existing Humboldt Bay Power Plant to mitigate loading and voltage concerns in the time-constrained portfolio that had the largest amount of additional renewable generation in the area. In lieu of SPS, upgrades of the overloaded transmission lines may be implemented.

4.7.1.2 North Coast and North Bay Area

The North Coast and North Bay areas are located between the Humboldt area and San Francisco and include Mendocino, Lake, Sonoma and Marin counties and parts of Napa and Solano counties. The reliability studies described in Chapter 2 assumed that two new renewable generation projects will develop in these areas by 2016. A new 10 MW biomass generation project was assumed to be connected to the Lakeville #2 (Petaluma-Lakeville) 60 kV line. The second project, a 35 MW geothermal plant, was modeled to be connected to the Geysers #3-Cloverdale 115 kV line. In the renewable studies, these projects were not modeled in any of the portfolios. The base portfolio had 334 MW of new renewable generation in the North Coast and North Bay areas. The environmentally constrained portfolio had 342 MW, the trajectory portfolio had 10 MW and the time-constrained portfolio had 286 MW. The new projects were located mainly in the North Coast area along the coast and in the Sonoma County, except the trajectory portfolio which had only small distributed generation in both the North Coast and North Bay areas.

4.7.1.2.1 Study Results and Discussion

Following is a summary of the study results of facilities in the North Coast and North Bay areas that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns. Only facilities that are negatively impacted by additional renewable generation are included.

Thermal Overloads

Eagle Rock-Cortina 115 kV transmission line

Eagle Rock-Cortina 115 kV transmission line may overload with the Eagle Rock-Fulton Silverado 115 kV line outage (category B contingency) under off-peak load conditions in the base and the environmentally constrained portfolio. This overload is caused by a large renewable generator connected to the Mendocino Substation, which was modeled in these cases. If this generator were tripped with the Eagle Rock-Fulton-Silverado 115 kV line outage, the Eagle Rock-Cortina 115 kV line overload would be mitigated. Tripping some of the Geysers generation, such as Geysers 5-6 would also mitigate the overload and would be more effective than tripping the Mendocino generator. Another alternative would be an upgrade of the overloaded sections of the Eagle Rock-Cortina 115 kV line if the renewable generation at Mendocino develops.

Fulton-Hopland 60 kV transmission line

Fulton-Hopland 60 kV transmission line is expected to overload under peak- and off-peak load conditions with category C contingencies in the base and environmentally constrained portfolio and with a category B contingency under off-peak load conditions in the environmentally constrained portfolio. The contingency that causes the overload is an outage of the Eagle Rock-Fulton Silverado 115 kV line either by itself (in the environmentally constrained off-peak case) or together with an outage of another transmission line in the same corridor in other cases of overload. As with the Eagle Rock-Cortina 115 kV line overload described above, this overload is mainly caused by a large renewable project at Mendocino modeled in the base and environmentally constrained portfolios. Tripping either this generation or some generation in the Geysers area (Geysers 5-6) in case of the emergency overload would mitigate the overload. Another alternative would be an upgrade of the overloaded line sections.

Fulton-Calistoga 60 kV transmission line

The section of the Fulton-Calistoga 60 kV transmission line between Middletown and Calistoga was identified as overloaded with category B and C contingencies in the base and environmentally constrained portfolios under peak load conditions. Under off-peak load conditions, this section may overload with a category B outage in the environmentally constrained portfolio and with category C contingencies in the base and environmentally constrained portfolios. The outage causing the overload was the Eagle Rock-Fulton Silverado 115 kV line either by itself or together with an outage of another transmission line in the same corridor. As with other overloads caused by this outage, the main reason was a large renewable project connected to the Mendocino

60 kV bus modeled in the base and environmentally constrained portfolios. Tripping this generation in case of the overload will mitigate it. Even more effective will be tripping some of the Geysers generation in the Eagle Rock area, such as Geyser 5-6. Overload of the Middletown-Calistoga 60 kV line section for category C contingencies was also identified in the reliability studies (see Chapter 2). The proposed mitigation was to open this line section in case of overload. In the renewable portfolios, opening the Middletown-Calistoga section would cause overload on the Fulton-Hopland 60 kV line so that generation tripping will still be required. Therefore, opening of the Middletown-Calistoga section is not recommended. Another alternative would be an upgrade of the Middletown-Calistoga 60 kV line section.

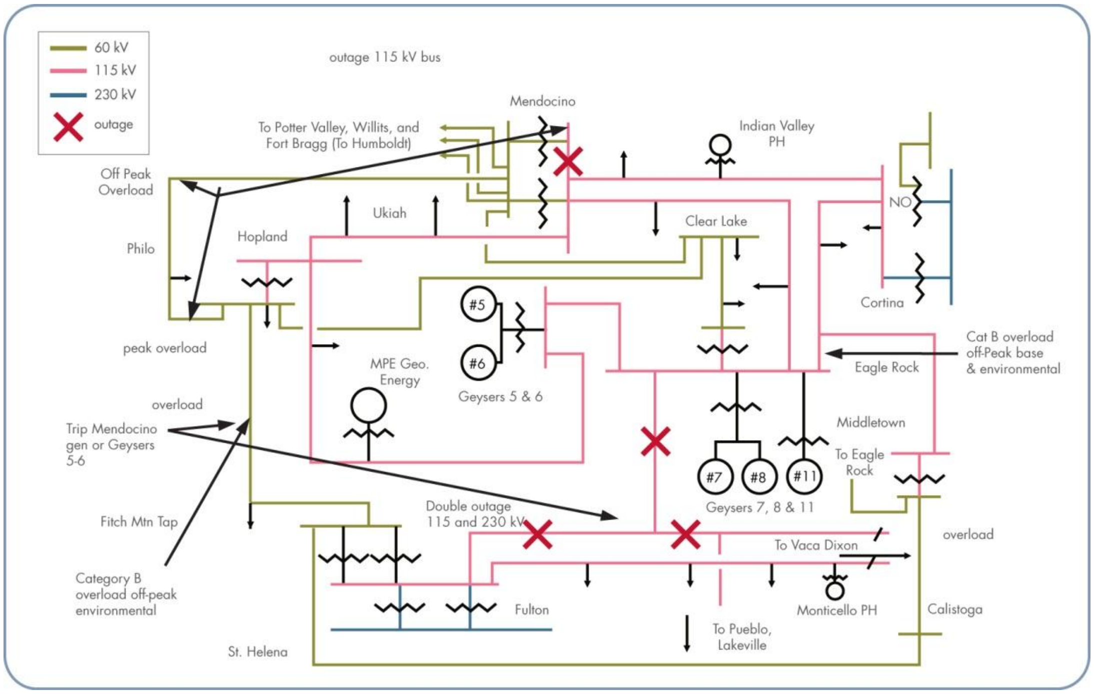
The St. Helena-Calistoga section of the same Fulton-Calistoga 60 kV transmission line may overload under off-peak load conditions in the environmentally constrained portfolio with an outage of the Eagle Rock-Fulton-Silverado 115kV and the Geysers #9-Lakeville 230 kV Lines (category C). This is the same outage that causes the overload on the Middletown-Calistoga section. Tripping the renewable generation project at Mendocino or some of the Geysers generation would also eliminate overload on this line section. An upgrade or re-rate of the St. Helena-Calistoga 60 kV section would be another alternative.

Mendocino-Philo-Hopland 60 kV transmission line

Mendocino-Philo-Hopland 60 kV transmission line may overload with an outage of the Mendocino 115 kV bus (category C contingency) under peak load conditions in the trajectory and time-constrained portfolios. This transmission line was also identified as overloaded with the same outage in the reliability studies described in Chapter 2, but additional renewable generation exacerbates the overload. Under the off-peak load conditions, the Mendocino-Philo-Hopland line may also overload for the Mendocino 115 kV bus outage in the base portfolio. Tripping the renewable generation connected to the Mendocino 60 kV bus would mitigate the overload in the off-peak scenario, but under the peak load conditions, some tripping of load would be required. In the reliability studies, it was recommended to trip some load at the Philo and Elk 60 kV substations for overload with the Mendocino 115 kV bus outage. This mitigation would also work in the renewable portfolios.

The observed thermal overload problems and solutions are illustrated in Figure 4.7-4.

Figure 4.7-4 North Coast area overloads



Voltage Issues

Voltage and Voltage Deviation Concerns

The studies determined that under normal conditions with all facilities in service, high voltages may occur on the 115 kV and 60 kV buses in the Eagle Rock-Mendocino area for all renewable portfolios under peak and off-peak load conditions. An outage of the Mendocino 115/60 kV transformer drives voltages in the Mendocino 60 kV system even higher, and the Hartley-Clear Lake 60 kV outage creates high voltage in the Upper Lake 60 kV area. High voltages are explained by injection of power from renewable plants on the sub-transmission system. A solution to these concerns is to require all new solar PV generators, including distributed generation, to provide 0.95 lead/lag power factor capability and to adjust transformer taps on the Mendocino, Eagle Rock and Fulton 115/60 kV transformers.

The studies identified large voltage deviations (with voltage going down) in the Garberville-Laytonville 60 kV system for an outage of the Willits-Laytonville 60 kV line in all portfolios under peak load conditions. Large voltage deviations were also identified in the environmentally constrained portfolio under off-peak conditions. Two buses, Covelo and Laytonville 60 kV, may have voltage down to 0.89 per unit with this outage in all portfolios, except the environmentally constrained portfolio under peak load conditions. Large voltage deviations were also observed with the Willits-Laytonville 60 kV line outage in the reliability studies, but the addition of renewable resources makes voltage deviations larger. A solution to this concern is the proposed project to construct a new Bridgeville-Garberville 115 kV transmission line. This project was discussed in Chapter 2 and in Section 4.7.1.1 of this chapter, which discusses the

Humboldt area. Another alternative is to install voltage support in the area, but it would not mitigate the thermal overloads for which the new transmission line was proposed.

Another concern includes over 5 percent voltage deviation (with voltage going down) at the Corona 115 kV bus with the Lakeville-Corona 115 kV line outage in the base and time-constrained portfolios. There is also an over 5 percent deviation at the St. Helena 60 kV bus with the Lakeville #1 60 kV line outage in all portfolios, except the environmentally constrained portfolio. Both of these concerns occur under peak load conditions. A solution to the voltage deviation at Corona is to require a new renewable project connected to the adjacent Bellevue 115 kV Substation to provide 0.95 lead/lag power factor capability. St. Helena voltage deviation requires either installation of a shunt capacitor at St. Helena or disabling automatic load transfer with the Lakeville #1 line outage, in which case the load at the Dunbar Substation will be lost. Another solution is an exemption, allowing slightly larger voltage deviation at this bus, since the largest voltage deviation on St. Helena observed in the studies was 5.2 percent. The voltage concerns identified in the studies are illustrated in Figures 4.7-5 and 4.7-6.

Figure 4.7-5: Voltage concerns in the Bridgeville-Garberville 60 kV system

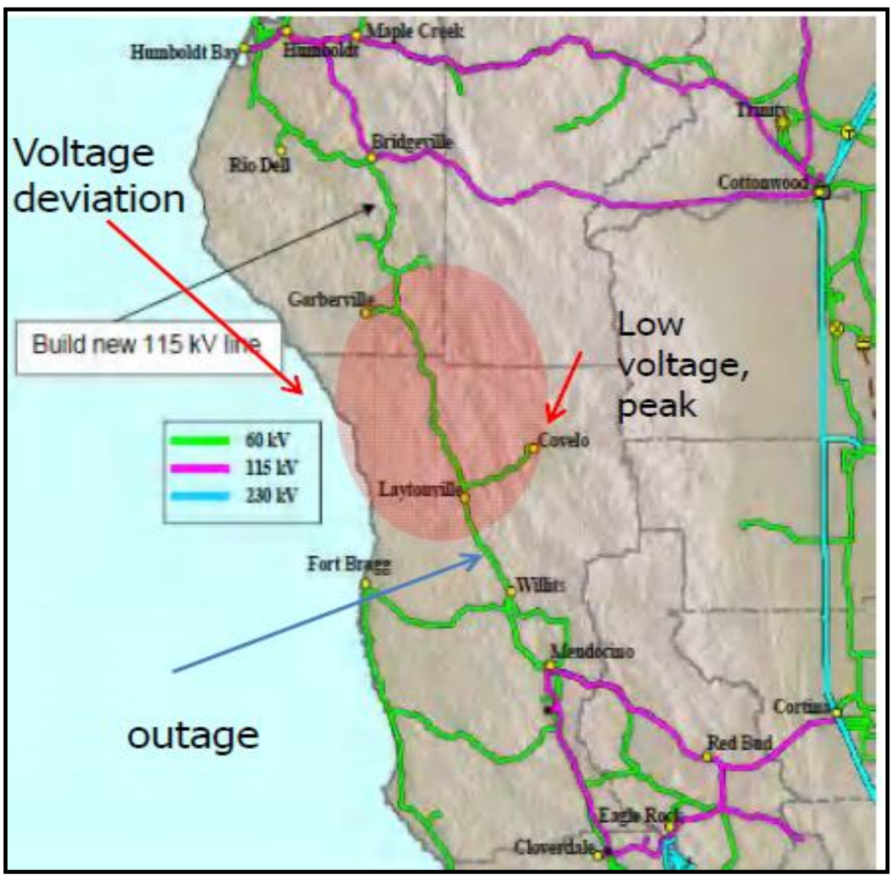
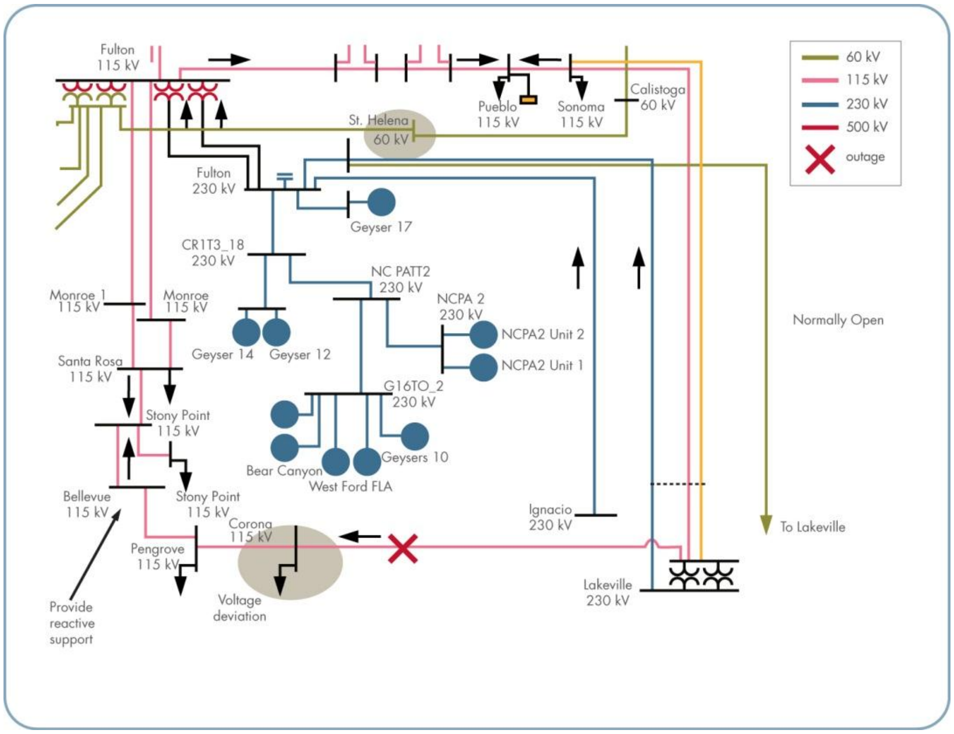


Figure 4.7-6: Voltage concerns in the Corona-Lakeville area



4.7.1.2.2 Conclusions

The studies showed that the existing transmission system in the North Coast area is adequate to accommodate additional renewable generation assumed to be developed in the four portfolios. No additional transmission upgrades will be necessary. The new Bridgeville-Garberville 115 kV Transmission Line Project proposed in the reliability studies of the Humboldt area would mitigate voltage concerns that may be exacerbated by additional generation projects.

The study results showed that thermal overloads in the North Coast area were mainly caused by a large renewable generation project connected to the Mendocino 60 kV bus in the base and environmentally constrained portfolios. An outage of the Eagle Rock-Fulton-Silverado 115 kV transmission line either alone or with another transmission line outage may cause overload of four transmission lines. Installing an SPS that would trip this project in case of overloads will mitigate overloads on all four transmission lines. Tripping some of the Geysers generation would also mitigate these overloads. Another alternative is to upgrade the four overloaded transmission lines.

The studies also identified high voltages under normal conditions that can be mitigated by requiring all solar PV generators, including distributed generation, to provide 0.95 lead/lag power factor capability and by adjusting transformer taps on the 115/60 kV transformers in the area.

No thermal overload or voltage concerns related to the new renewable generation were identified in the North Bay area, because there is a relatively small amount of new renewable generation in this area.

4.7.1.3 North Valley Area

This area includes the Northern end of the Sacramento Valley and parts of the Siskiyou and Sierra mountain ranges and foothills. The reliability studies described in Chapter 2 modeled the new 103 MW Hatchet Ridge wind plant connected to the Round Mountain-Pit River #3 230 kV transmission line. This project started commercial operation in November 2010. No future renewable projects were modeled in the North Valley area in the reliability studies. In addition to the Hatchet Ridge plant, the renewable portfolio studies included 121 MW of new renewable projects in the base portfolio and 489 MW in the environmentally constrained portfolio. No projects were included in the trajectory portfolio, and 46 MW were modeled in the time-constrained portfolio. In addition to the projects in the North Valley and Sierra areas, the totals in the environmentally constrained portfolio include a power plant located in the Lassen Municipal Utility. The majority of these projects are small distributed PV generators with total capacity not exceeding 20 MW, with the exception of several larger projects in the Cottonwood and Trinity area in the base and environmentally constrained portfolios.

4.7.1.3.1 Study Results and Discussion

Following is a summary of the study results of facilities in the North Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns. Only facilities that are negatively impacted by additional renewable generation are included.

Thermal Overloads

Trinity-Cottonwood 115 kV transmission line

Trinity-Cottonwood 115 kV transmission line may overload in the environmentally constrained portfolio with an outage of the Bridgeville-Cottonwood 115 kV transmission line under peak load conditions. This overload was caused by a renewable generation project modeled at the Trinity 115 kV bus. Installing an SPS to trip this generation would mitigate the overload. Overload of this line with another outage and the SPS to trip Trinity generation was also described in Section 4.7.1.1, which assessed the Humboldt area with the renewable generation portfolios. Another alternative is an upgrade of the Trinity-Cottonwood 115 kV transmission line.

Cottonwood 230/115 kV transformer bank #1

Overload of the Cottonwood 230/115 kV transformer bank #1 is expected with an outage of the parallel Cottonwood 230/115 kV bank #4 in the environmentally constrained portfolio under peak load conditions. The mitigation solution is either to trip renewable generation at Trinity and/or Wildwood that was assumed to be on line in this portfolio or to re-rate the transformer.

Keswick-Cascade 60 kV transmission line

Keswick-Cascade 60 kV transmission line may overload with category B and C contingencies under peak load conditions in the time-constrained and environmentally constrained portfolios. The most critical outage is the Cottonwood-Trinity 115 kV line.

In the time-constrained portfolio, the main reason for this overload is low output of the portion of the Humboldt Bay power plant connected to the 60 kV system. This overload can be prevented by dispatching at least two 60 kV units from the Humboldt Bay power plant under peak load conditions. In the environmentally constrained portfolio, the flow on the Keswick-Cascade 60 kV line is in the opposite direction, and the overload is mainly caused by new renewable projects connected to the Trinity 115/60 kV Substation. Installing an SPS that would trip some of the Trinity generation will mitigate the overload. Another mitigation alternative is upgrading the Keswick-Cascade 60 kV line.

In the environmentally constrained portfolio, an outage of the Cottonwood-Trinity 115 kV line may cause overload on the Keswick-Trinity-Weaverville 60 kV line under peak load conditions. As in the case of the Keswick-Cascade 60 kV line, tripping some of the new renewable generation assumed to be connected to the Trinity Substation in this portfolio would mitigate the overload. Another mitigation alternative is upgrade of this line.

Because of the high amount of renewable generation in the North Valley area in the environmentally constrained portfolio, the following facilities are expected to overload if this renewable generation develops.

Kilarc-Deschutes 60 kV transmission line

Kilarc-Deschutes 60 kV transmission line is expected to overload under both peak and off-peak load conditions. This line may overload under normal conditions with all facilities in service, and under various category B and C contingencies. The overload is caused by a new renewable project at Kilarc. Power injection from this project causes high voltages that will require installation of a shunt reactor, which will cause even higher overload of this transmission line. The proposed mitigation solution is to reconductor the line if this renewable project develops.

Cascade-Deschutes 60 kV transmission line

Cascade-Deschutes 60 kV transmission line is expected to overload in the environmentally constrained portfolio under off-peak load conditions with an outage of the parallel Cascade-Benton-Deschutes 60 kV line (category B). The proposed mitigation solution is either to install an SPS that would trip Kilarc generation with this outage in case of overload, or to reconductor the overloaded line sections.

Coleman-Red Bluff 60 kV transmission line

A section of the Coleman-Red Bluff 60 kV transmission line may overload in the environmentally constrained portfolio under off-peak load conditions with an outage of the parallel Coleman-Cottonwood 60 kV line (category B). The proposed mitigation solution is installing an SPS that would trip renewable generation connected to the Inskip 60 kV bus in this portfolio or trip a generator at the Coleman 60 kV bus. Another alternative is an upgrade of the overloaded section of the Coleman-Red Bluff 60 kV line.

Palermo-Big Bend 115 kV transmission line

Palermo-Big Bend 115 kV transmission line is expected to overload in the environmentally constrained portfolio under off-peak load conditions. The outage that may cause this overload is Caribou-Table Mountain 230 kV line (category B). Since the amount of overload was not significant (2 percent), the requirement for new renewable generation in the Big Bend and Grizzly areas to provide 0.95 lead/lag power factor will mitigate the overload. Another alternative is to trip a renewable generation project in the Grizzly-Big Bend area.

Voltage Issues

Voltage and Voltage Deviation Concerns

The studies determined that with all facilities in service, high voltages may occur under peak load conditions in the Coleman area in the base portfolio and in the Kilarc and Trinity areas in the environmentally constrained portfolio. In addition, on the Trinity 115 kV and 60 kV buses, large voltage deviations with voltage increasing were observed in the environmentally constrained portfolio under peak load conditions with a category C contingency (outage of the Cottonwood 115 kV bus).

Under off-peak load conditions, high voltages were observed in all portfolios with all facilities in service (category A contingency). The voltages were especially high in the Kilarc area.

A mitigation solution for the high voltages is to require 0.95 lead/lag power factor capability for the new distributed generation and other renewable projects in the area. In addition, transformer tap adjustment at the Cottonwood and Trinity 230/115 kV transformers is required in all portfolios and installation of a shunt reactor at the Kilarc 60 kV Substation is required in the environmentally constrained portfolio. The required size of the reactor is approximately 18 MVar.

Figures 4.7-7 and 4.7-8 illustrate the reliability concerns and the mitigations in the North Valley area.

Figure 4.7-7: Loading and voltage concerns in the Cascade-Cottonwood area

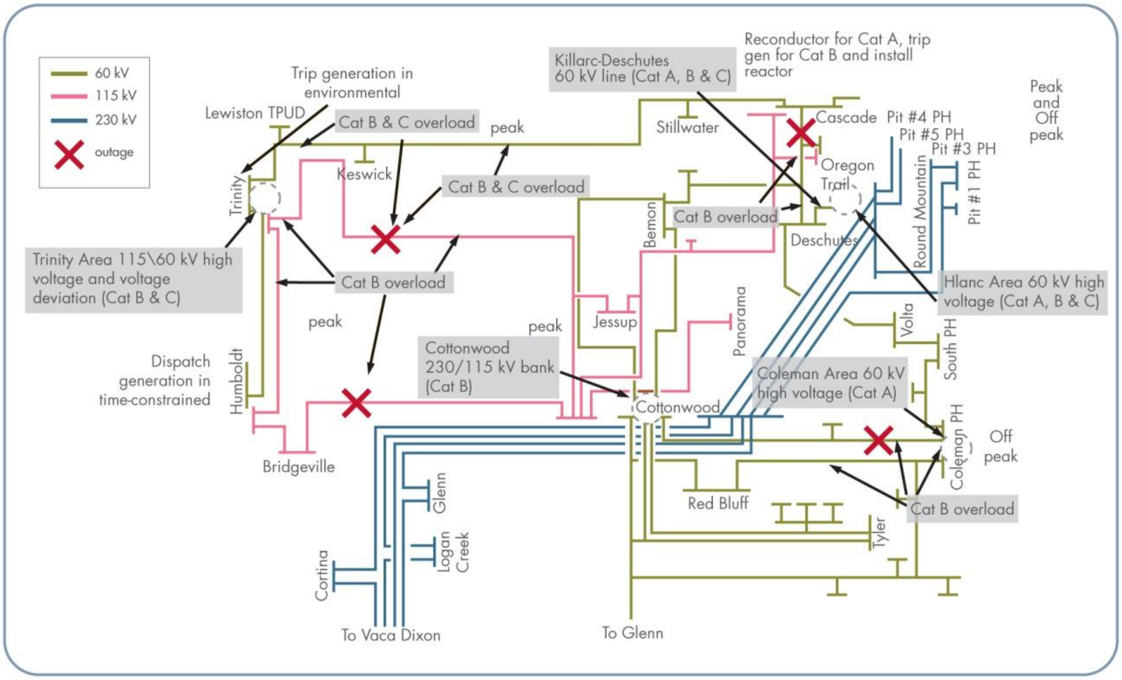
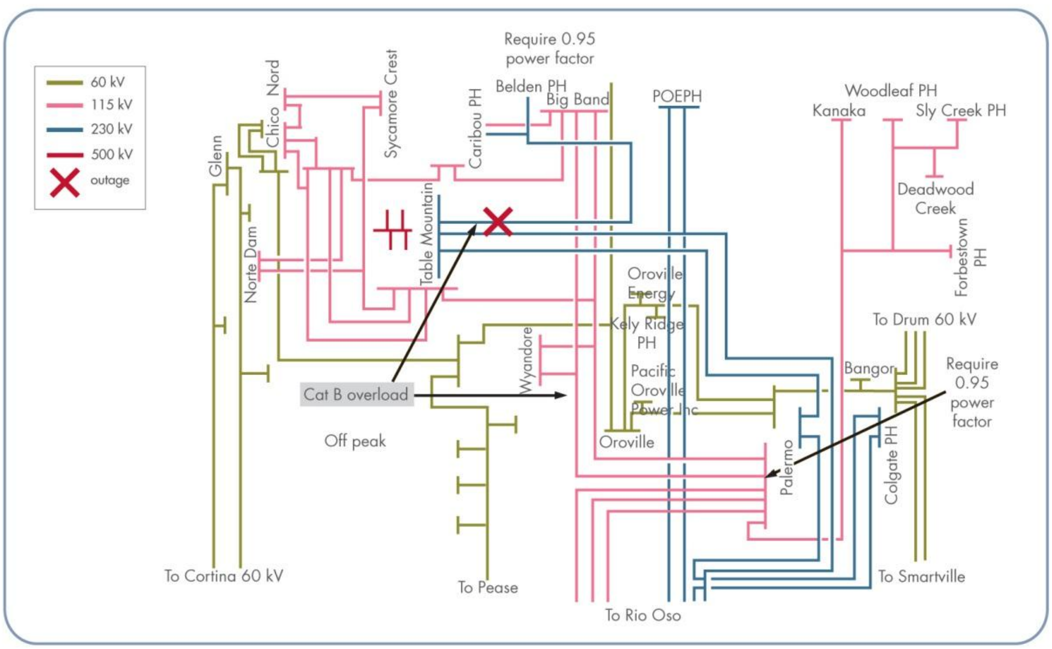


Figure 4.7-8: Loading and voltage concerns in the Table Mountain area



4.7.1.3.2 Conclusions

The studies showed that the existing transmission system in the North Valley area is adequate to accommodate additional renewable generation assumed to be developed in most of the portfolios studied without additional transmission upgrades. The only exception is for the environmentally constrained portfolio. In the environmentally constrained portfolio, the Kilarc-Deschutes 60 kV transmission line needs to be upgraded and a shunt reactor installed at the Kilarc 60 kV Substation. In addition, an SPS to trip new renewable generation connected to the Trinity 115/60 kV Substation for category B and C overloads would need to be developed in the environmentally constrained portfolio. Under peak load conditions, at least two generation units connected to the 60 kV at the existing Humboldt Bay Power plant would need to be dispatched in all renewable portfolios. Under off-peak load conditions in the environmentally constrained portfolio, some new renewable generation interconnected to the 60 kV systems in the Kilarc and Coleman areas would need to be tripped with category B contingencies. In lieu of an SPS to trip generation, transmission system upgrades may be implemented. New renewable projects would be required to provide 0.95 lead/lag power factor capability to avoid excessively high voltages.

4.7.1.4 Central Valley Area

The Central Valley area includes the central part of the Sacramento Valley, and it is composed of the Sacramento, Sierra, Stockton and Stanislaus divisions. The reliability studies described in Chapter 2 modeled several existing and new renewable projects. This included the Wadham and Woodland biomass projects in Sacramento; the wind generation projects Enxco, Solano, Shiloh and High winds in Solano county; and existing small hydro projects in the Sierra and Stanislaus divisions. In the renewable portfolios, additional renewable generation was modeled in the Central Valley area. In the base portfolio, 325 MW were assumed to be located in the Sacramento area (including Solano), 122 MW in Sierra, 364 MW in Stockton-Modesto and 69 MW in Stanislaus. In the trajectory portfolio, 870 MW of new renewable resources were located in the Sacramento area (including Solano county), 15 MW in Sierra and 481 MW in Stockton-Modesto with no new renewable resources in Stanislaus. In the time-constrained portfolio, 249 MW of new renewable resources were assumed to be located in Sacramento, including 197 MW connected to the Sacramento municipal utility system, 25 MW in Sierra, 243 MW in Stockton-Modesto and 19 MW in Stanislaus, including the Turlock Irrigation district. In the environmentally constrained portfolio, 431 MW of new renewable generation was assumed to be connected to the PG&E system and 727 MW to the Sacramento municipal utility in the Sacramento area. Also in this scenario, 335 MW was located in the Sierra area, 397 MW in Stockton-Modesto and 163 MW in Stanislaus including 40 MW in Turlock. Thus, the Central area had a total of 880 MW of new renewable resources in the base portfolio, 1,366 MW in the trajectory portfolio, 536 MW in the time-constrained portfolio and 2,053 MW in environmentally constrained portfolio. However, not all of this generation was modeled at full output in the studies.

4.7.1.4.1 Study Results and Discussion

Following is a summary of the study results of facilities in the Central Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns. Only facilities that are negatively impacted by additional renewable generation are included.

Thermal Overloads

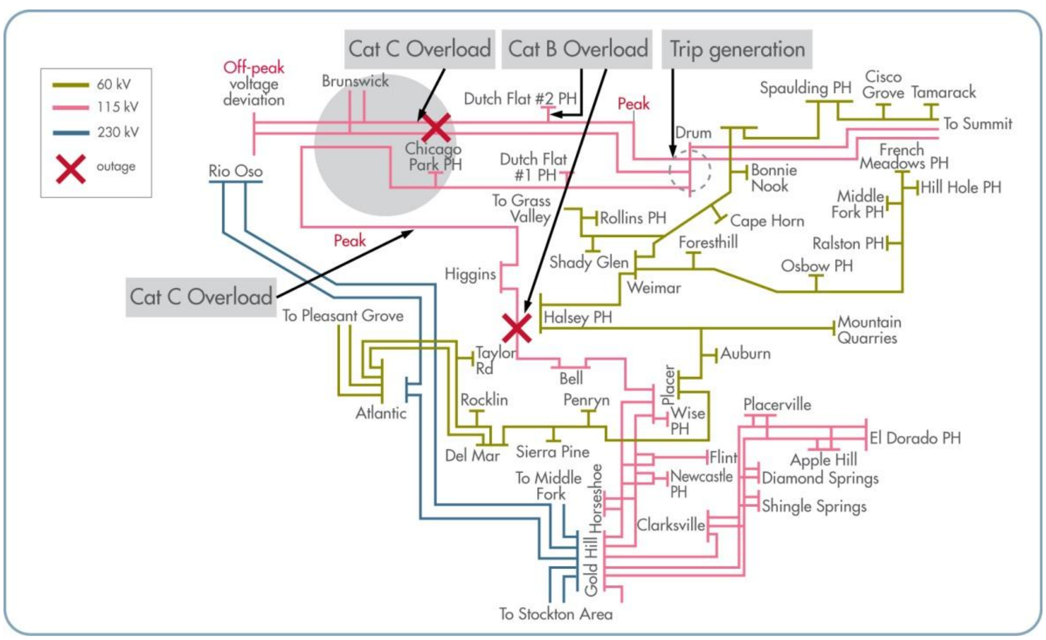
Under peak load conditions, thermal overloads were identified only in the Sierra area in the environmentally constrained portfolio.

Drum-Rio Oso 115 kV Transmission Line

Drum-Rio Oso 115 kV transmission line is expected to overload with the Drum-Bell 115 kV line outage (category B), and Drum-Higgins 115 kV transmission line is expected to overload with an outage of both Drum-Rio Oso 115 kV transmission lines (category C contingency). The most effective mitigation solution for these overloads will be tripping some of the generation connected to the Drum 115 kV bus. Another mitigation alternative is an upgrade of the overloaded transmission lines.

The overloads in the Drum area are illustrated in Figure 4.7-9 below.

Figure 4.7-9: Overload and voltage concerns in the Southern Sierra area



Under off-peak load conditions, three transmission lines in the Sierra area were identified as overloaded. These overloads were identified only in the environmentally constrained portfolio.

Colgate-Challenge 60 kV and Colgate-Alleghany 60 kV transmission lines

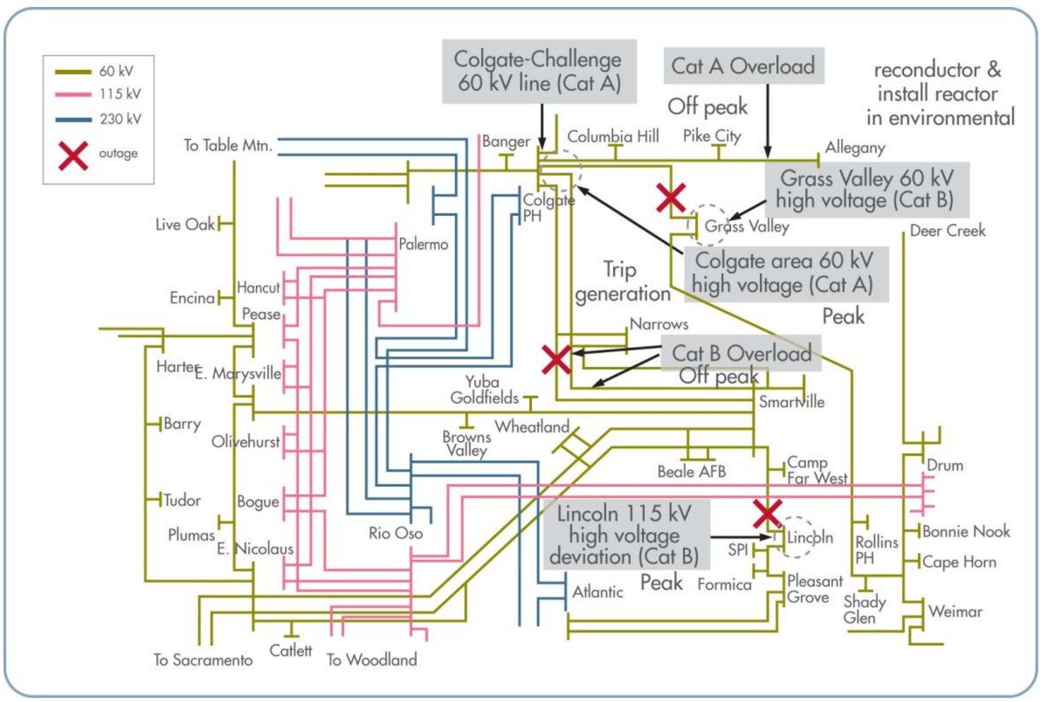
Colgate-Challenge 60 kV and Colgate-Alleghany 60 kV transmission lines may overload under normal conditions because of the renewable generation connected to these lines. A mitigation solution is to reconductor the overloaded sections.

Colgate-Smartsville # 2 60 kV Transmission Line

The Colgate-Narrows section of the Colgate-Smartsville # 2 60 kV transmission line is expected to overload with an outage of the parallel Colgate-Smartsville #1 60 kV line (category B). Mitigation solutions to this overload are either to install an SPS that would trip generation at Narrows for this outage in case of the overload, or to upgrade the overloaded line section.

These reliability concerns are illustrated in Figure 4.7-10.

Figure 4.7-10: Overload and voltage concerns in the Northern Sierra area



Cortina 230/60 kV transformer bank #1

In the Sacramento area, an overload was identified on the Cortina 230/60 kV transformer bank #1 under off-peak load conditions in the environmentally constrained portfolio. The overload may occur with an outage of the parallel Cortina 230/115 kV transformer bank #4. To mitigate this overload, some of the generation connected to the Cortina 60 kV system in this portfolio would need to be tripped (either the existing unit at Wadham or one of the renewable projects). Another mitigation alternative is to upgrade the Cortina 230/60 kV bank.

No other thermal overloads were identified in the Sacramento area despite the large amount of renewable generation modeled in the trajectory and environmentally constrained portfolios. This can be explained by the fact that the direction of power flow is from Sacramento to the Bay area. Therefore, additional generation output (especially from the plants located in the Solano County), increases loading on the Bay Area transmission facilities, rather than on those located in Sacramento.

In the Stockton area, three 115 kV transmission lines between Stanislaus and Manteca were identified as overloaded with category B and C contingencies under off-peak load conditions in the environmentally constrained portfolio.

River Bank Junction-Manteca 115 kV transmission line

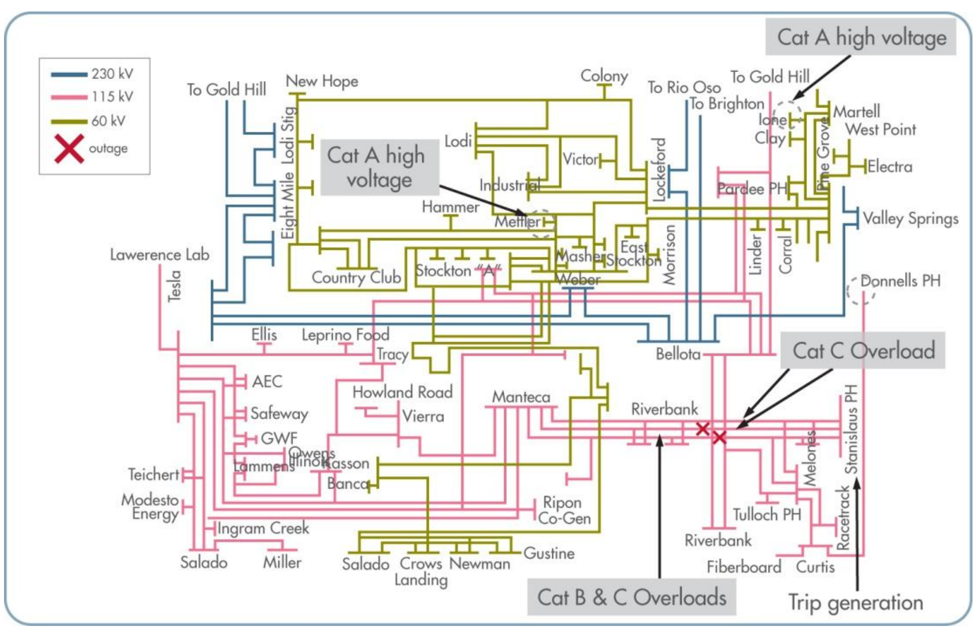
River Bank Junction-Manteca 115 kV transmission line may overload with category B (Bellota-Riverbank-Melones 115 kV) outage and category C outage of the two 115 kV transmission lines between Stanislaus and Manteca.

Stanislaus-Melones-Manteca 115 kV and Stanislaus-Melones 115 kV transmission lines

Stanislaus-Melones-Manteca 115 kV and Stanislaus-Melones 115 kV transmission lines are expected to overload with an outage of the two parallel lines in the same corridor (category C contingency): Stanislaus-Melones and River Bank Junction-Manteca. The reliability studies described in Chapter 2 also identified overload on these transmission lines, and additional renewable generation exacerbates the overloads. Mitigation for the Stanislaus-Melones-Manteca and Stanislaus-Melones 115 kV line overloads would be installation of an SPS that would trip generation at Stanislaus and Stockton in case of overloads. If overload persists, tripping generation at Donnelis would mitigate it. Another alternative would be an upgrade of the overloaded transmission lines.

Stockton area overloads are illustrated in Figure 4.7-11.

Figure 4.7-11: Overload and voltage concerns in the Stockton area



Voltage Issues

Voltage and Voltage Deviation Concerns

The studies determined that with all facilities in service, high voltages may occur under peak load conditions in the Colgate area in Northern Sierra in the environmentally constrained portfolio. Under off-peak load conditions with all facilities in service, high voltages were observed in the Sacramento and Stockton areas. The first part of the mitigation solution for high voltages caused by power injection from the renewable generation in the sub-transmission system is to require the renewable projects and distributed generation to provide 0.95 lead/lag power factor capability. In addition, a shunt reactor would be needed at the Alleghany 60 kV Substation in the Northern Sierra (Colgate) area. The required size of the reactor is approximately 18 MVar, and it is needed in the environmentally constrained portfolio.

Another concern is large voltage deviations in the Grass Valley 60 kV system under peak load conditions in the trajectory portfolio for an outage of Colgate-Grass Valley 60 kV transmission line. Large voltage deviations are also a concern in the Lincoln 115 kV system under peak load conditions in the environmentally constrained and time-constrained portfolios. These concerns can be mitigated by requiring new renewable projects to provide 0.95 lead/lag power factor capability. Under off-peak load conditions, large voltage deviations were observed in the Drum 115 kV system for category B contingencies of 115 kV lines from Drum. A 0.95 lead/lag power factor requirement for renewable projects would mitigate these concerns also.

The described voltage concerns are illustrated in the Figure 4.7-9 through 4.7-11 above.

4.7.1.4.2 Conclusions

The studies showed that the existing transmission system in the Central Valley area is adequate to accommodate additional renewable generation assumed to be developed in most of the portfolios studied without additional transmission upgrades. The only exception is in the environmentally constrained portfolio. In the environmentally constrained portfolio, two 60 kV transmission lines in the Colgate area need to be upgraded and a shunt reactor installed at the Alleghany 60 kV Substation. In addition, several SPSs need to be developed in this portfolio. This includes: an SPS to trip existing hydro generation in the Drum area for category B and C peak overloads; an SPS to trip existing generation at Narrows for off-peak category B overload; a third SPS to trip generation at Cortina; and a fourth SPS to trip generation in Stockton for category B and C overloads under off-peak conditions. In lieu of the SPSs to trip generation, transmission system upgrades may be implemented.

New renewable projects would be required to provide 0.95 lead/lag power factor capability to avoid excessively high voltages and large voltage deviations in the environmentally constrained, time-constrained and trajectory portfolios.

4.7.1.5 Greater Bay Area

This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties. For the transmission performance evaluation, it is divided into three sub-areas: East Bay, South Bay and San Francisco-Peninsula. In the reliability studies described in Chapter 2, one new renewable generation project was included in the Bay area generation; the 162 MW High Winds wind power plant that is connected to the Birds Landing Substation in Solano County. This project was also considered in the reliability studies for the Central Valley area. Renewable portfolio studies included additional renewable generation in the Bay area. The base portfolio had 80 MW of new renewable generation in the East Bay, 21 MW in the South Bay and no new renewable generation in San Francisco-Peninsula. The trajectory portfolio also did not have any new generation in San Francisco-Peninsula. That portfolio had 28 MW in the East Bay and 10 MW in the South Bay. The time-constrained portfolio modeled 135 MW of renewable generation in the East Bay, 89 MW in South Bay and 35 MW in San Francisco- Peninsula. The environmentally constrained portfolio assumed 433 MW of new renewable projects in the East Bay, 252 MW in the South Bay and 109 MW in San Francisco-Peninsula.

The majority of the renewable projects modeled in the Bay area were small distributed photovoltaic generators.

4.7.1.5.1 Study Results and Discussion

Following is a summary of the study results of facilities in the Greater Bay Area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns. Only facilities that are negatively impacted by additional renewable generation are included.

Thermal Overloads

Under peak load conditions, three transmission lines in the East Bay area were identified as overloaded.

Contra Costa Substation-Contra Costa 230 kV transmission line

Contra Costa Substation-Contra Costa 230 kV transmission line may overload with category B contingencies in the base and environmentally constrained portfolios and with category C contingencies in the base portfolio. The most critical single contingency is an outage of the parallel Contra Costa-Birds Landing 230 kV transmission line. The most critical double contingency is an outage of two 230 kV transmission lines between Vaca Dixon and Lambie and Peabody. This overload is explained by high generation output of the wind power plants connected to the Birds Landing 230 kV Substation. A mitigation solution to this overload is to install an SPS that would trip some of the generation connected to Birds Landing in case of the overload. Another alternative would be the upgrade of the Contra Costa Substation-Contra Costa transmission line. Overload of this transmission line was also identified in the reliability studies described in Chapter 2 for category B and C contingencies, and new wind generation projects in the Birds Landing area aggravated the overload.

Lone Tree-Cayetano 230kV transmission line

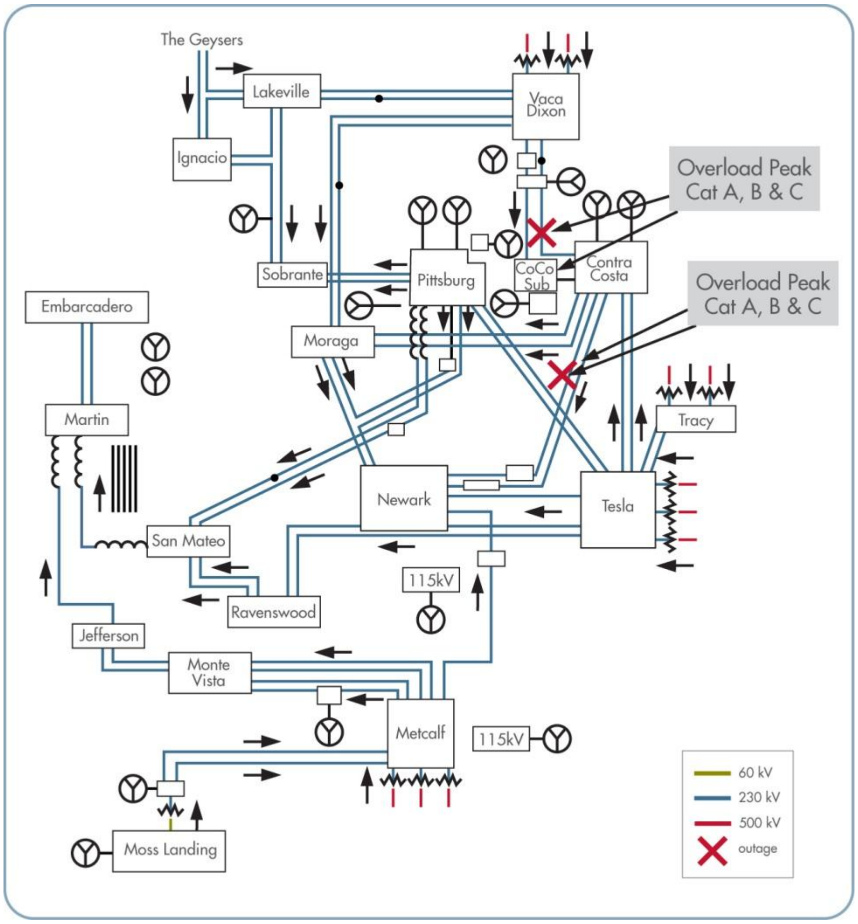
Lone Tree-Cayetano 230kV transmission line is expected to overload under normal conditions with all facilities in service and under category B and C contingency conditions. category A and B overloads are expected in the base portfolio, and category C overloads are expected in the base, time-constrained and trajectory portfolios. The most critical single contingency is an outage of the parallel Contra Costa-Las Positas 230 kV transmission line. The most critical double contingency is an outage of both Contra Costa-Moraga 230 kV circuits. These overloads are explained by high generation in the Contra Costa area. Congestion management to reduce some of the Contra Costa generation and an SPS that would automatically trip generation with contingencies would mitigate the overloads. Another alternative is to upgrade the Lone Tree-Cayetano 230 kV transmission line.

Christie-Sobrante 115 kV transmission line

Christie-Sobrante 115 kV transmission line may overload with an outage of the Sobrante-El Cerrito Station G #1 and #2 115 kV lines (category C). This overload is expected in all renewable portfolios. Possible mitigation solutions are to re-rate or reconductor the line or to trip some load at the El Cerrito Substation with this contingency. This overload was also observed in the reliability studies under summer peak load conditions of 2021, as described in Chapter 2. Additional renewable generation contributed to the higher flow on the Christie-Sobrante line and the overload in the renewable portfolios was higher. In the reliability studies, the ISO recommended re-rating or reconductoring the line, and in interim, to develop an SPS to drop load.

No thermal overloads caused or exacerbated by additional renewable generation were identified in other regions of the Greater Bay area under peak load conditions, and no overloads were identified under off-peak load conditions for any of the renewable portfolios. Figure 4.7-12 shows the simplified Bay Area diagram and the identified overloads

Figure 4.7-12: Greater Bay area thermal overload concerns



Voltage Issues

Voltage and Voltage Deviation Concerns

Additional distributed renewable generation may cause high voltages under normal conditions with all facilities in service. Under peak load conditions, high voltages were observed in the Contra Costa 60 kV system in the environmentally constrained portfolio and in the San Jose Evergreen area in the time and environmentally constrained portfolios. These portfolios had more distributed renewable generation in San Jose than the other two portfolios, and the environmentally constrained portfolio had more distributed generation around Contra Costa.

Sufficient mitigation to alleviate voltage concerns under peak load conditions is to require 0.95 lead/lag power factor capability for distributed generation in the Contra Costa and San Jose areas and to adjust transformer taps on the Contra Costa 115/60 kV transformers and the Evergreen 115/60 kV transformer. Another alternative is to install shunt reactors on the buses where high voltages were identified.

Under off-peak load conditions, high voltages were also observed with all facilities in service (category A contingency). In the Peninsula area, all portfolios had high voltages. The environmentally constrained portfolio had high voltages in the San Jose

115 kV and 60 kV systems and in the East Bay 60 kV system. The time-constrained portfolio had high voltages around Contra Costa. To mitigate high voltages in the Peninsula area, distributed generation in the area needs to maintain 0.95 lead/lag power factor, and transformer taps on the Martin 115/60 kV transformer need to be adjusted. To mitigate high voltages in the San Jose area under off-peak load conditions, a 0.95 lead/lag power factor requirement and adjustment of transformer taps at the Evergreen 115/60 kV transformer would be required. To mitigate high voltages in the East Bay, adjustment of the transformer taps on the Christie 115/60 kV transformers would be required. To reduce voltages in the Contra Costa area, adjustment of transformer taps on the Contra Costa 115/60 kV banks is required.

The studies have not identified any voltage deviation concerns in any of the renewable portfolios.

4.7.1.5.2 Conclusions

The studies showed that the existing transmission system in the Greater Bay Area is adequate to accommodate additional renewable generation assumed to be developed in all the portfolios studied without significant additional transmission upgrades. The only change that may be considered is an upgrade of the Lone Tree-Cayetano 230 kV transmission line to avoid congestion management needed to reduce loading of this line. Other overload that may occur with category B and C contingencies under peak load conditions can be mitigated by installing SPSs that would trip generation at Contra Costa or Bird Landing 230 kV substations. Some load tripping may be required for one category C contingency in the East Bay for all renewable portfolios, as well as for the scenario when renewable generation does not develop. In lieu of SPS to trip generation and load, transmission system upgrades may be implemented. No loading concerns were identified under off-peak load conditions.

New renewable projects would be required to provide 0.95 lead/lag power factor capability to avoid excessively high voltages.

According to tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are required in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are required in the base case, but which are not required in any of the stress scenarios or are required in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the PG&E North area did not identify any new transmission additions or upgrades that qualify as category 1 or category 2 elements as identified issues for the various scenarios can be addressed with SPS.

4.7.2 Southern PG&E Area

PG&E's Southern area is made up of all the counties south of Stanislaus county and North of the SCE service territory. For the purpose of this analysis, it consists of PG&E's Greater Fresno, Kern, Central Coast and Los Padres areas.

Figure 4.7.1 shows the South PG&E division for this analysis. The details of all the individual areas have already been captured in Chapter 2. The scope of this analysis is limited to reporting the transmission issues resulting exclusively because of the renewable portfolio. The total South PG&E generation consists of the expected Westland CREZ and Carrizo South generation, the non-CREZ and the distributed generation in the Central Coast, Los Padres, and Greater Fresno and Kern areas. The details of the modeled generation, the total renewable capacity and the on peak and off-peak dispatch are listed below in table 4.7-5 and 4.7-5, respectively.

Figure 4.7-13 Southern PGE system

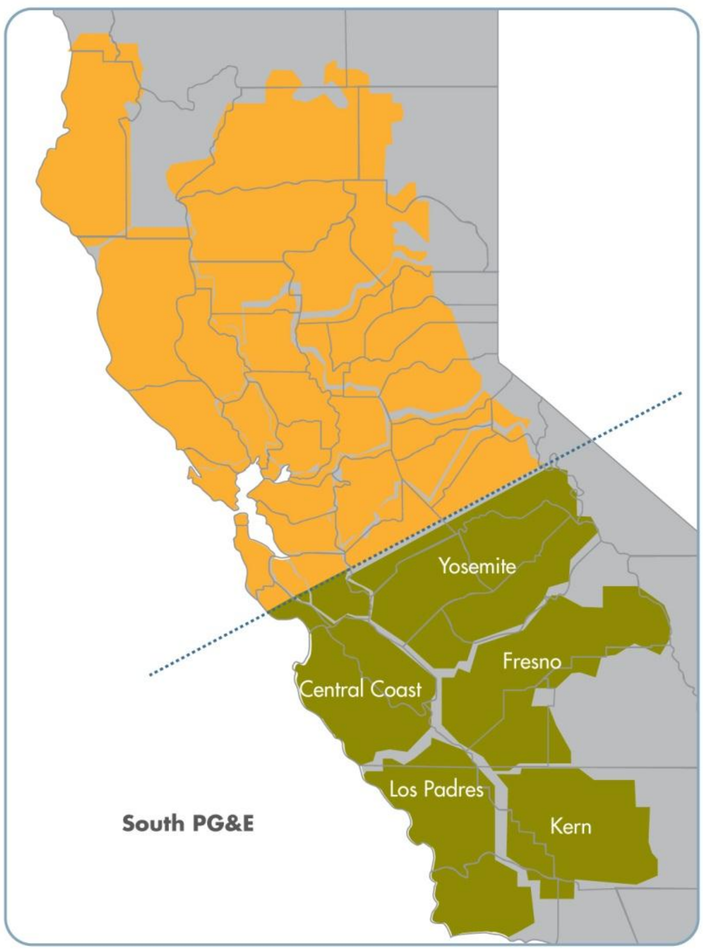


Table 4.7-4: Summary of renewable generation in South PG&E area

Area	Renewable Generation by portfolio (MW)			
	Base	Environmentally constrained	Trajectory	Time-constrained
PG&E South (CREZ)*	900	1,700	900	900
PG&E South (Non-CREZ)	178	101	178	334
PG&E South (DG)	795	1561	491	370
Total	**1,872**	**3,361**	**1,569**	**1,604**

* Carrizo South & Westland CREZ

Table 4.7.5 Summary of renewable generation dispatch in PGE south

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Base	1837	1174	1055
Environmental	3361	2284	3225
Trajectory	1604	1417	477
Time Constrained	1569	1286	1457

4.7.2.1 Fresno and Kern Area

4.7.2.1.1 Study Results and Discussion

Following is a summary of the study results of facilities in the Fresno and Kern area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingencies. The discussion includes proposed mitigation plans for these reliability concerns. The reporting has been limited to the new problems or any incremental problems identified in the reliability analysis.

Thermal Overloads

Giffen Junction-Westland 70 kV Junction

This section of the line was found to be overloaded under category A, B and C contingencies in the base, environmentally constrained and time-constrained portfolios under off-peak conditions. category A contingency showed the worst overload. For the portfolios, the environmentally constrained showed the worst overload because of the additional distributed generation modeled. The line has a normal rating of 42 MVA and an emergency rating of 48 MVA. A reconductor or an SPS to back off non-distributed generation in the area would mitigate all the category A, B and C overloads.

Giffen Junction-San Joaquin 70 kV Junction

This section of the line was found to be overloaded under category A, B and C contingencies in the base, environmentally constrained and time-constrained portfolios under off-peak conditions. category A contingency showed the worst overload. For the portfolios, the environmentally constrained showed the worst overload because of the additional distributed generation modeled. The line has a normal rating of 42 MVA and an emergency rating of 48 MVA. A reconductor or an SPS to back off non-distributed generation in the area would mitigate all category A, B and C overloads.

Helm-San Joaquin 70 kV Junction

This section of the line was found to be overloaded under category A, B and C contingencies in the base, environmentally constrained and time-constrained portfolios under off-peak conditions. category A contingency showed the worst overload. For the portfolios, the environmentally constrained showed the worst overload because of the additional distributed generation modeled. The line has a normal rating of 77 MVA and an emergency rating of 90 MVA. A reconductor or an SPS to back off non-distributed generation in the area would mitigate all category A, B and C overloads.

Derrick-Tornado 70 kV Line

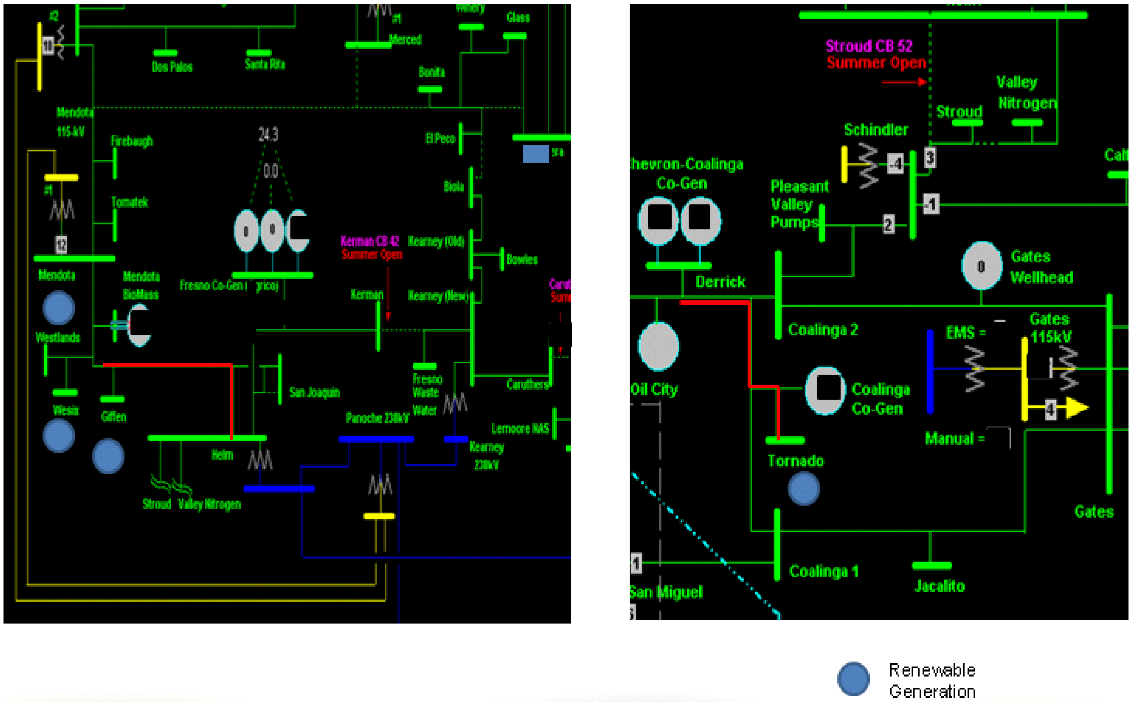
This section of the line was found to be overloaded under category A, B and C contingencies in the environmentally constrained portfolio under off-peak conditions. category A contingency showed the worst overload. The line has a normal rating of 31 MVA and an emergency rating of 36 MVA. A reconductor is the only option as the existing units in the area, such as Coalinga generation, are QF and congestion management might not be a feasible option. Also, the DG modeled at Tornado 70 kV bus cannot be backed down using an SPS option.

Kerman-Agrico 70 kV Junction

This overload was observed in all the peak portfolios. The line was found to be overloaded in the annual reliability assessment as well. There is also some distributed generation modeled in the area. The mitigation for the overload would come from the annual reliability assessment and would be sufficient to alleviate the overload observed in this analysis.

Figure 4.7.13 summarizes all the Fresno 70 kV off-peak problems.

Figure 4.7-14: Fresno 70 kV overloads



Warnerville-Wilson 230 kV line

category A and C5 contingency overloads were observed in the trajectory portfolio under off-peak conditions. This off-peak condition overload is a three-pumping plant case; therefore, the recommendation is to either reconductor or use congestion management (i.e., turn off the #3 Helms pump or turn on other effective units in the Fresno area).

Gates 500/230 kV transformer bank

This overload was observed in the base and trajectory off-peak conditions for the three-pump portfolio following the loss of the Los Banos 500/230 kV bank. This off-peak condition overload is a three-pumping plant case; therefore, the recommendation is to modify Helms RAS to accommodate this contingency in order to drop the #3 Helms pump. The other option is to rerate the transformer or develop a higher short-term emergency rating. A new transmission project is also a viable alternative, but more analysis needs to be done to identify this as the best solution.

Gates-Midway 230 kV line

This overload was observed in the base and trajectory off-peak conditions for the three-pump portfolio following the loss of the Gates 500/230 kV bank. This off-peak condition overload is a three-pumping plant case; therefore, the recommendation is to modify Helms RAS to accommodate this contingency in order to drop the #3 Helms pump. Another option is to rerate the transmission line or develop a higher short-term 30-minute rating. A third option is to identify some generators in the Midway area that can be effectively used to mitigate the overload. A new transmission project is also a viable alternative but more analysis needs to be done in order to identify this as the best solution.

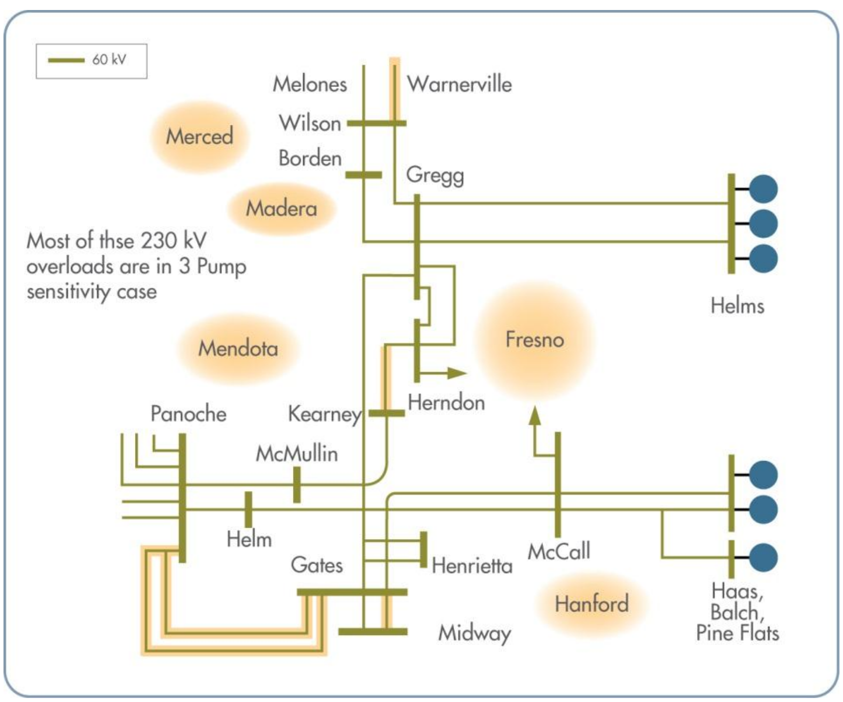
Kearney-Herndon 230 kV line

This overload was observed in the trajectory off-peak conditions for the three-pump portfolio. The worst overload was observed for the category C5 contingency, Gates-Gregg and Gates-Ashlan 230 kV lines. This off-peak condition overload is a three-pumping plant case; therefore, the recommendation is to modify Helms RAS to accommodate the contingency in order to drop the #3 Helms pump. The alternate mitigation is to rerate the transmission line or develop a higher short-term 30-minute rating. A new transmission project is also a viable alternative but more analysis needs to be done in order to identify this as the best solution.

Gates-Panoche 230 kV

The overload was observed in all of the off-peak conditions three-pump portfolios. It was also observed in the environmentally constrained off-peak conditions for the one-pump portfolio. The worst contingency is a category C5, Gates-Gregg-Gates-McCall 230 kV line. The modification of Helms RAS to drop the #3 Helms pump was not adequate to relieve the overload. One option is modification of Helms RAS along with the congestion management that would involve backing off flows on Path 15. A higher 30-minute rating of the transmission lines may also relieve the need of congestion management along with Helms RAS modification. A new transmission project is also a viable alternative but more analysis needs to be done in order to identify this as the best solution. The following figure shows the overloads on the 230 kV Fresno system.

Figure 4.7-15: Fresno 230 kV off-peak overloads



Legrand-Exchequer 115 kV line

This line is overloaded under peak load conditions in the environmentally constrained portfolio. This overload was observed as a category B contingency of Merced 115 kV Bank #2. Modification of an existing Exchequer RAS may be used to relieve the overload on this line. If modification of RAS in not possible, a reconductor of this line would mitigate the overload.

Fameso-Cawelo-Ogle Junction 115 kV section

This line was found to be overloaded in the base and environmentally constrained portfolios under off-peak conditions. The overload was a result of category B and C contingency conditions. The worst contingency is a category C on the Live Oak-Kern Oil and Kern-Lerdo-Kern Oil 115 kV lines. Since it is an off-peak problem, the recommendation is to perform congestion management. A reconductor or an SPS to drop the renewable generation would also work to mitigate the overload.

Lerdo-Ogle Junction 115 kV section

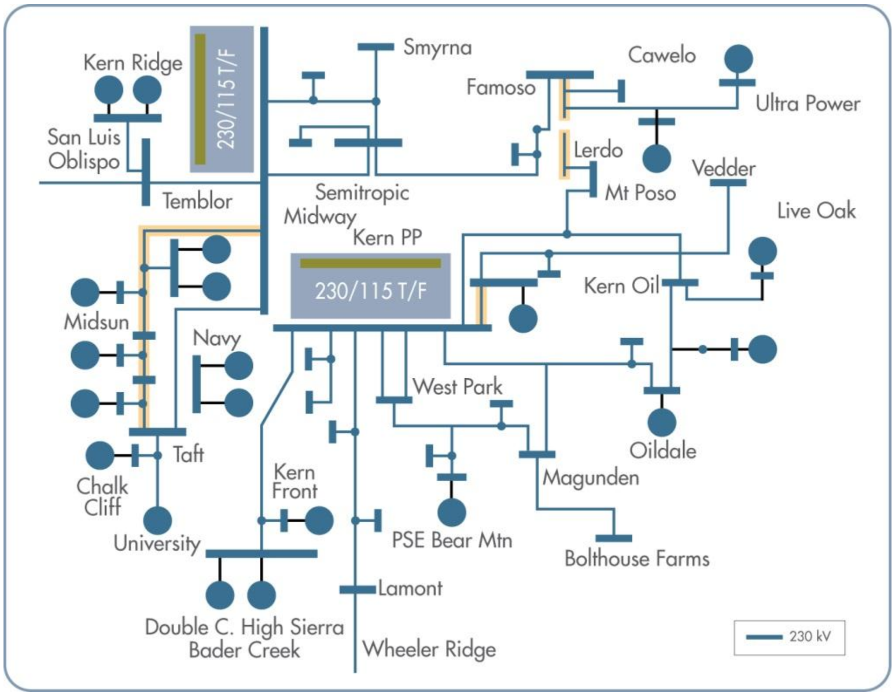
This line was found to be overloaded in all the peak portfolios. The overload was a result of a category C5 contingency condition of Midway-Kern #3 and Midway-Kern #4 230 kV lines. A reconductor or an SPS to drop the renewable generation would mitigate the overload.

Midway-Santa Maria 115 kV line sections

The following sections of this line were found to be overloaded in the environmentally constrained portfolio under off-peak conditions: Midway-Cymric 115 kV; Cymric-Texaco 115 kV; Fellows-Morgan 115 kV; Midsun-Fellows 115 kV; and Morgan-Midset. All these sections were found to be overloaded for the contingency of Midway-Taft 115 kV line. Because this is an off-peak problem, the recommendation is to use congestion management. Reconductoring these limiting sections would also mitigate the thermal overloads.

Figure 4.7-16 shows the details of the overloads seen in the Kern area.

Figure 4.7-16: Kern area overload summary



Voltage Issues

Off-Peak Voltage and Voltage Deviation Concerns

Forty-seven unique off-peak high voltage issues were seen in Fresno and Kern spread out among different portfolios. In the Fresno area, most of the high voltage issues were identified in the environmentally constrained one-pump scenario under off-peak conditions. All of these were observed under normal conditions. In the Kern area, high voltages on the buses were spread out among all the portfolios. Most of the identified high voltage concerns were seen as a result of a high distributed generation concentration in the environmentally constrained portfolios. In the Fresno area, a couple of voltage deviations were identified in the trajectory off-peak conditions three-pumping plant case. These are the problems that become incrementally worse than those identified in the reliability analysis. The mitigation for these problems was identified in the reliability analysis. As already mentioned, the lack of reactive power control on the distributed generation caused the high voltage issues seen in these cases. A variable (0.95 lead/lag) power factor capability for these generators would mitigate the high voltage problems seen in the analysis.

On-Peak Voltage and Voltage Deviation Concerns

In the Fresno area, six category B contingency low voltage violations were observed in all portfolios under peak conditions. All of these violations were also observed in the reliability analysis, and they become incrementally worse in this analysis. Additionally, eight category B contingency voltage deviation problems were observed in all the portfolios under peak conditions. These problems also became incrementally worse than those identified in the reliability analysis. The reliability mitigation projects would resolve all of the voltage problems seen in this analysis. In the Kern area, a couple of high voltage issues were seen in the environmentally constrained and time-constrained portfolios. Additionally, there was a voltage deviation issue on one of the buses in the environmentally constrained portfolio for a category B contingency condition. A variable (0.95 lead/lag) power factor capability for the nearby renewable generators would mitigate this identified issue.

4.7.2.1.2 Conclusion

In the Fresno area, the observed thermal issues were primarily seen in the Helms three-pump sensitivity analysis. Most of these issues can be resolved by modifying the existing Helms RAS and congestion management. A capital transmission project would also mitigate all the problems, but this creates additional issues in various peak portfolios. Most of the low voltage 70 kV issues were observed because of inadequate capacity of the lines at lower voltage levels. At this point, generic solutions such as an SPS for dispatchable renewable generators, congestion management or reconductor have been proposed. Most of the voltage issues were primarily driven by lack of power factor control on the renewable generators. Variable reactive power capability on these generators would mitigate the voltage issues identified in this analysis. Any common voltage problems between the reliability analysis and this analysis that become incrementally worse would be alleviated using the mitigation identified in the reliability analysis. According to ISO tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are included in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are included in the base case, but which are not included in any of the stress scenarios or are included in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the Fresno and Kern area did not identify any new transmission additions or upgrades that qualify as category 1 or category 2.

4.7.2.2 Central Coast and Los Padres Area

4.7.2.2.1 Study Results and Discussion

Following is a summary of the study results of facilities in the Central Coast and Los Padres area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns. The reporting has been limited to the new problems or any incremental problems identified in the reliability analysis.

Thermal Overload

Morrobay-Q166 230 kV #1 and #2 lines

This overload was observed in the time-constrained off-peak conditions for the Helms three-pump scenario. Either of these lines becomes overloaded for contingency of the other 230 kV line. Since the amount of overload is not significant, the line can be rerated to mitigate the problem. Alternate mitigation would be to develop an SPS to trip renewable generators in the area to relieve the overload.

Voltage Issues

There were no significant voltage violations to report for this area.

4.7.2.2.2 Conclusion

According to ISO tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are included in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are included in the base case, but which are not included in any of the stress scenarios or are included in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the Central Coast and Los Padres did not identify any new transmission additions or upgrades that qualify as category 1 or category 2.

4.7.3 PG&E Bulk Transmission System

The PG&E area bulk system assessment for the four renewable generation portfolios was performed with the same methodology that was used for the reliability studies described in Chapter 2. All single and common mode 500 kV system outages were studied, as were outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to ground faults for all four portfolios. For the off-peak system conditions, the studies were performed with an assumption that the Helms pump storage power plant operates in the pumping mode with three units pumping, and also with an assumption that it operates with one unit pumping. Post transient and transient stability studies were conducted for all the cases and scenarios.

Transient stability studies did not identify any criteria violations or undamped oscillations.

For the post transient (governor power flow) studies, only transmission facilities 230 kV and higher were monitored because lower voltage facilities were studied with other outages in the detailed assessments of the PG&E areas that were described earlier.

The study results are discussed below with only those facilities that are negatively impacted by additional renewable generation being included.

4.7.3.1 Study Results and Discussion

Thermal Overloads

Under peak load conditions, thermal overloads were identified only in the Bay Area and the overloaded facilities were the same 230 kV transmission lines that were identified in the Greater Bay Area renewable generation studies described in Section 4.7.1.5.

Lone Tree-Cayetano 230 kV transmission line

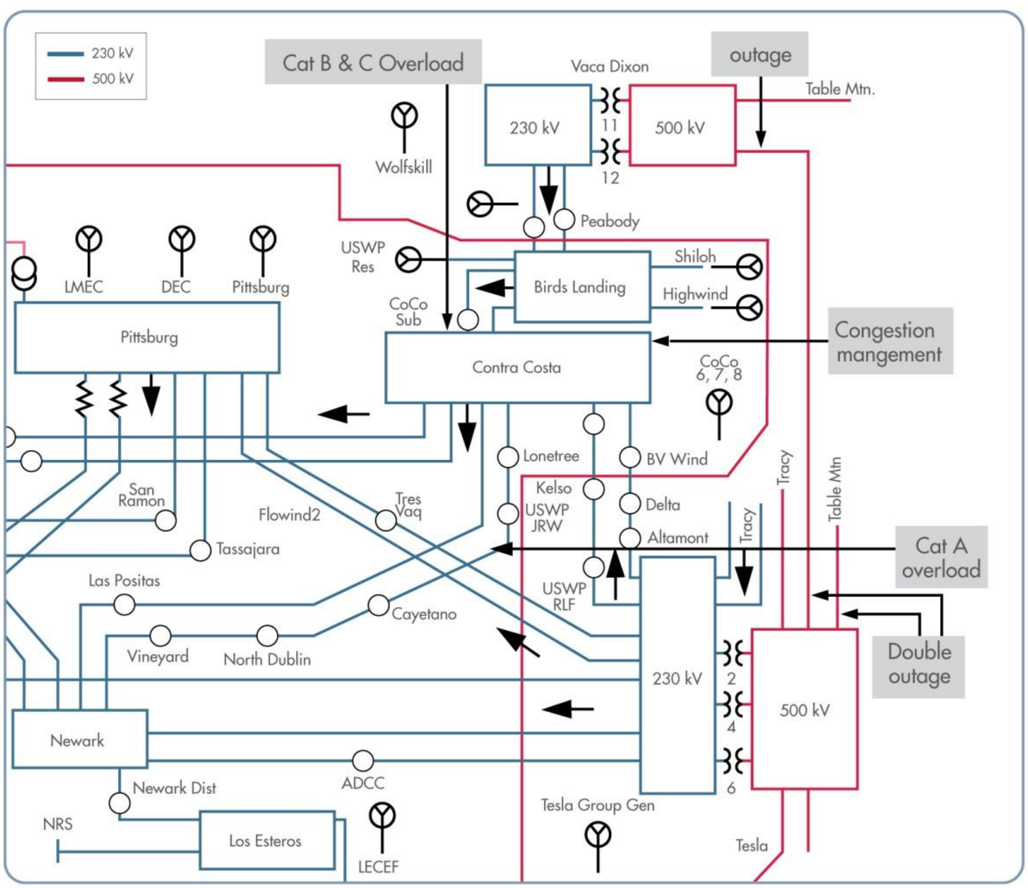
The sections of the Lone Tree-Cayetano 230 kV transmission line between Lone Tree and Cayetano were identified as overloaded under normal conditions in the base portfolio. As stated in Section 4.7.1.5, the mitigation solutions are either upgrade of these line sections or congestion management of generation at Contra Costa and Contra Costa Substation.

Contra Costa Substation-Contra Costa 230 kV transmission line

Contra Costa Substation-Contra Costa 230 kV transmission line may overload with category B and C contingencies of the 500 kV lines between Vaca Dixon and Tesla or Tracy in the base and environmentally constrained portfolios. The same transmission line was identified as overloaded in the Bay Area studies in the same renewable portfolios with 230 kV outages. Mitigation for this overload is to install an SPS to trip generation at Contra Costa Substation or Bird Landing in case of the overload or to upgrade the line.

Loading concerns in the PG&E bulk system under peak loading conditions are illustrated in Figure 4.7.17.

Figure 4.7-17: Thermal overloads in the Bay area under peak load conditions



The following transmission facilities were identified as overloaded in the off-peak scenarios. All these facilities are located in the southern part of the PG&E system. These overloads substantially depend on the operation of the Helms Pump Storage Plant, and the loading on these facilities is significantly higher if all three Helms units are on line operating in the pumping mode.

Gates-Midway 230 kV #1 transmission line

Gates-Midway 230 kV #1 transmission line may overload in the base, trajectory and time-constrained portfolios. If only one Helms pump is operating, this line is expected to overload with a double outage of the Midway-Gates and Midway-Los Banos 500 kV transmission lines (category C contingency). With three Helms units pumping, the Gates-Midway 230 kV line may also overload with a single outage of the Midway-Gates 500 kV line or an outage of the Gates 500/230 kV transformer (category B contingency). Loading on this transmission line depends on the remedial actions that are undertaken with the outages that cause the overload. The studies assumed different amounts of load and generation tripping to determine what the remedial actions should be so that the Gates-Midway 230 kV line would not overload. With one Helms pump, tripping up to 850 MW of load in Northern California, generation plants connected to the Midway Substation and the Helms pump would be sufficient to mitigate the overload in the base and trajectory portfolios. In the time-constrained portfolio, these actions were not sufficient, but with tripping of at least 250 MW of new generation connected to the Midway-Morro Bay 230 kV transmission lines, the overload was mitigated. The same remedial actions would be sufficient if three Helms pumps are operating, but instead of tripping one pump, all three Helms pumps would need to be tripped.

When three Helms units are operating in the pumping mode, the Gates-Midway 230 kV line may also overload for category B contingencies. In the environmentally constrained portfolio, the overload is not expected. In other portfolios, some remedial actions would be required to mitigate the overload. For the Midway-Gates 500 kV line outage, tripping of one Helms pump is sufficient to mitigate the overload in the base and time-constrained portfolios. In the trajectory portfolio, tripping of two Helms pumps would be required. With the Gates 500/230 kV transformer outage, tripping of two Helms pumps would be required in the base and time-constrained portfolios, but even tripping of all three Helms pumps would not be sufficient to mitigate the overload in the trajectory portfolio. In this portfolio, some generation at Midway would also need to be tripped.

Another alternative would be upgrading the Gates-Midway 230 kV transmission line or the 500 kV system in the Fresno area.

Gates-Arco 230 kV transmission line

Gates-Arco 230 kV transmission line was identified as overloaded in the base and trajectory portfolios with three Helms units pumping for an outage of the Gates 500/230 kV transformer if no remedial actions are applied. With tripping of the two Helms pumps that is required in these renewable portfolios to mitigate the Gates-Midway 230 kV line #1 overload, no overload on the Gates-Arco 230 kV line was observed.

Instead of the remedial actions schemes or an SPS, upgrading the Gates-Arco 230 kV line or the 500 kV system in the Fresno area can be implemented to mitigate the overload.

Panoche-Gates 230 kV #1 and #2 transmission lines

Panoche-Gates 230 kV #1 and #2 transmission lines may overload with an outage of the Gates-Gregg and Gates-McCall 230 kV transmission lines. If the Helms pump storage plant is operating with one pump and this pump is tripped for the Gates-Gregg/Gates-McCall double outage, the overload would be expected in the trajectory portfolio. With three Helms units pumping, tripping two Helms pumps would be sufficient to mitigate the overload in the base portfolio, but not in the other portfolios. Tripping of three Helms pumps would mitigate the overload in the time-constrained portfolio, but for the trajectory portfolio, the Panoche-Gates 230 kV lines would need to be upgraded. The environmentally constrained portfolio has two new generation plants connected to the Gates-Gregg and Gates-McCall 230 kV transmission lines. If the Gates-Gregg and Gates-McCall sections between the Gates Substation and the switching station connecting these new plants are out of service, no overload on the Panoche-Gates 230 kV lines is expected with two Helms pumps being tripped. With an outage of the sections between the switching station and Gregg and between the switching station and McCall, even tripping all three Helms pumps would not be sufficient to mitigate the overload on the Panoche-Gates 230 kV lines. Adding the generation connected to the Gates-Gregg and Gates-McCall 230 kV lines to the SPS would mitigate the overload.

Panoche-Gates 230 kV #1 and #2 transmission lines may also overload in the environmentally constrained portfolio with other contingencies, such as Los Banos Gates 500 kV line #1, Los Banos-Midway 500 kV line or Los Banos 500 kV stuck breaker. Tripping new generation projects connected to the Gates-Gregg and Gates-McCall 230 kV lines in this portfolio would mitigate the overloads.

Other mitigation alternatives would be upgrading the Panoche-Gates 230 kV lines in all renewable portfolios or the 500 kV system in the Fresno area.

Warnerville-Wilson 230 kV transmission line

Warnerville-Wilson 230 kV transmission line may overload if all three units at the Helms Pump Storage plant are pumping. The overload is expected under normal and category B and C contingency conditions in the trajectory portfolio. If appropriate SPS are applied to the contingencies, such as tripping at least one Helms pump with the Gates 500/230 kV transformer outage and tripping at least two Helms pumps with the Gates-Gregg/Gates-McCall 230 kV double outage, no overload on the Warnerville-Wilson 230 kV line would be expected. To avoid overload under normal conditions, either this transmission line needs to be upgraded, or congestion management (i.e., decreasing generation in the Inskip-Kirkwood area) needs to be used. Upgrading the 500 kV system in the Fresno area would also mitigate this overload.

Gates-Gregg 230 kV transmission line

Gates-Gregg 230 kV transmission line between Henrietta and Gates may overload in the trajectory portfolio with several category B and C contingencies if three units at the Helms Pump Storage Plant are pumping. Upgrading this line section may be challenging because it is already equipped with a high capacity conductor. Tripping one Helms pump for category B contingencies and two Helms pumps for category C contingencies would mitigate the overload. Another alternative is an upgrading the 500 kV system in the Fresno area.

Gates 500/230 kV transformer bank

Gates 500/230 kV transformer bank may overload with category B and C contingencies in the base and trajectory portfolios. The most critical category B contingency — an outage of the Los Banos-Gates #1 500 kV transmission line — would require tripping one Helms pump in the base portfolio and two Helms pumps in the trajectory portfolio. category C contingencies would require tripping all Helms pumps in the trajectory portfolio and at least two pumps in the base portfolio.

Westley-Los Banos 230 kV transmission line

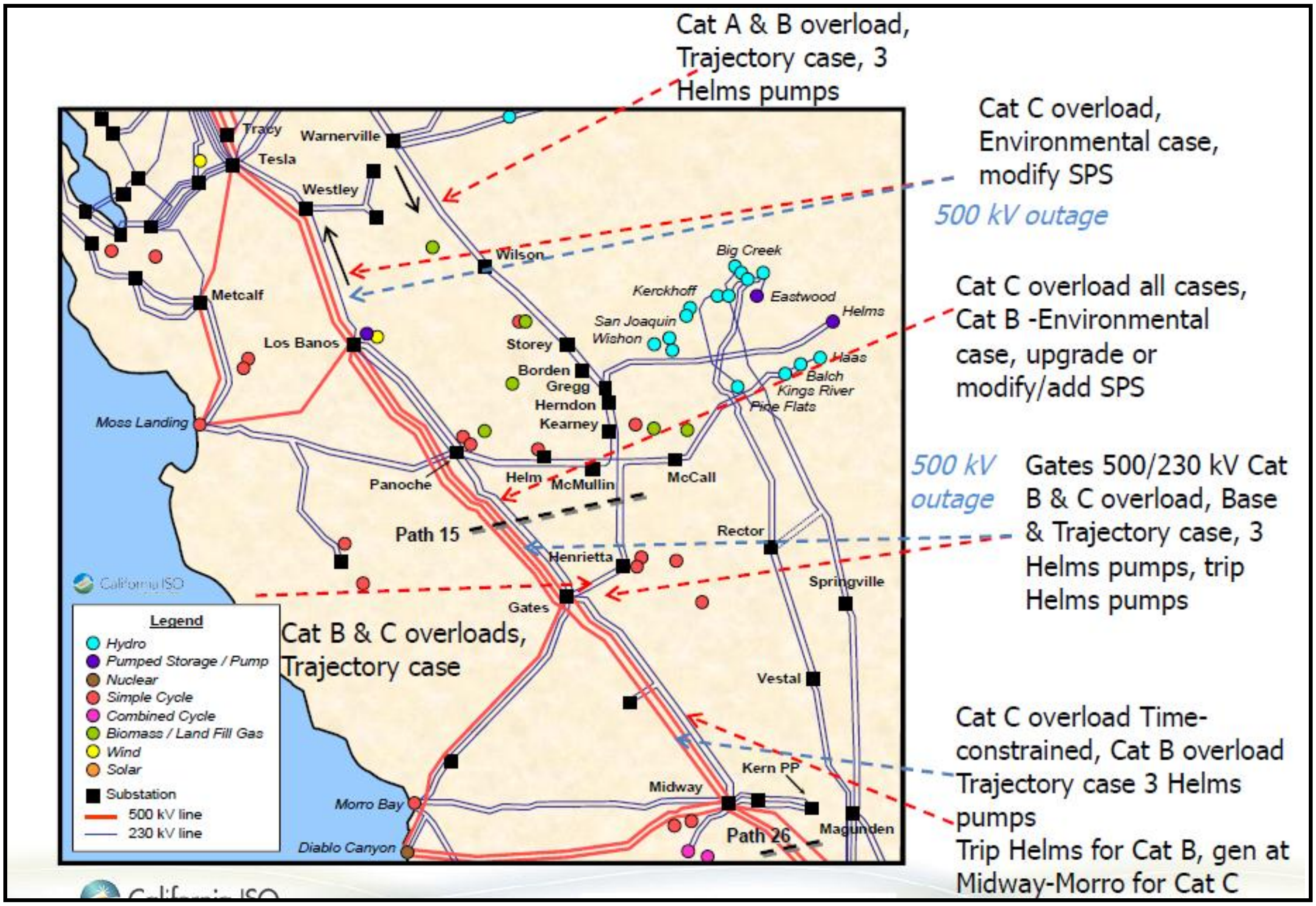
Westley-Los Banos 230 kV transmission line is expected to overload in the environmentally constrained portfolio with category C contingencies if one Helms unit is pumping and with category B and C contingencies if three Helms units are pumping. Mitigation solutions would be adding generation connected to the Gates Substation to the SPS for the Los Banos-Tracy and Los Banos-Tesla 500 kV double outage and installing an SPS to trip generation connected to the Gates-Gregg and Gates-McCall 230 kV transmission lines with single outages. Upgrading the 500 kV system in Fresno would be another alternative to mitigate this overload.

Midway-Gates 500 kV transmission line

Midway-Gates 500 kV transmission line was heavily loaded (up to 99 percent) under off-peak normal conditions in the environmentally constrained portfolio with three Helms units pumping even if the total flow on Path 15 was not reaching its limit (5,100 MW versus the Path 15 rating of 5,400 MW). Alternatives to the mitigation are congestion management (i.e., reducing generation at Midway) or upgrading the 500 kV system in the Fresno area.

Loading concerns in the South PG&E area under off peak conditions are illustrated in Figure 4.7-18.

Figure 4.7-18: Thermal overloads in the South PG&E area under off-peak load conditions



Voltage Issues

Voltage and Voltage Deviation Concerns

No voltage or voltage deviation concerns were identified on the PG&E bulk system in the studies in any renewable portfolios under peak load conditions.

Under off-peak load conditions, large voltage deviations were observed in the Fresno area with a double outage of the Midway-Los Banos and Midway-Gates 500 kV lines in the trajectory portfolio. In this case, the voltage deviation was towards higher voltage. The remedial actions for this outage were tripping all three Helms pumps and generation at Midway, as well as load in Northern California. To mitigate high voltages and voltage deviations, it is proposed to require all distributed generation in the Fresno area to provide 0.95 lead/lag power factor, and to insert the shunt reactor at the Gregg Substation with this contingency.

4.7.3.2 Conclusions

The studies of the bulk PG&E transmission system with the renewable generation portfolios identified 230 kV system overload in the Bay area under peak load conditions that can be mitigated by congestion management and installing SPS to trip generation for category B and C contingencies.

The off-peak studies, particularly with all three units at the Helms Pump Storage Power Plant are operating in a pumping mode, identified multiple overloads in the Fresno area. These overloads would require either complicated SPS and some transmission upgrades or a major upgrade to the 500 kV transmission system in the area, such as constructing a new 500 kV transmission line between Midway and Gregg substations and upgrading Gregg Substation to 500 kV or another alternative of one or several new 500 kV transmission lines. As indicated in Section 2.4.5 there may be potential benefits associated with modifications or upgrades to the bulk system in the Midway area. The needs of the area and the potential benefits are multi-faceted. With this a comprehensive study plan will be developed to assess the needs and benefits of bulk system modification alternatives in the area and will be included as a part of the 2012/2013 transmission planning cycle. The studies of the bulk PG&E transmission system with the renewable generation portfolios did not show any transient stability concerns.

According to ISO tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are required in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are required in the base case, but which are not required in any of the stress scenarios or are required in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the PG&E system did not identify any new transmission additions or upgrades that qualify as category 1 or category 2 elements as identified issues for the various scenarios can be addressed with SPS.

4.8 Policy Driven Assessment Results and Mitigations in SCE Area

4.8.1 SCE Area Overview

This section presents the results of the power flow and stability study that was performed for the SCE system for each of the four renewable generation portfolios. Power flow studies were performed for all credible contingencies in the SCE system, with the exception of category C3 contingencies, which were assumed to be mitigated by limiting generation following the first contingency. Post-transient and transient stability studies were performed for selected major single and double contingencies. For each portfolio, 2021 peak and off-peak load scenarios were studied.

The study was performed based on the general study methodology and assumptions described in previous sections. Specific assumptions applied to the SCE area in study are provided below.

Table 4.8-1 summarizes the renewable generation capacity modeled to meet the RPS net short in the SCE system in each portfolio by renewable energy zone. Table 4.8-2 provides further breakdown of the distributed generation by deliverability area. Table 4.8-3 shows the generation output from the new renewable generators in each portfolio.

Table 4.8-1 Renewable Generation in the SCE system modeled to meet the 33% RPS net short

Zone	Base portfolio	Environmentally Constrained	Trajectory	Time Constrained
Kramer	362	62	62	62
Mountain Pass	523	-	888	-
Palm Springs	178	178	77	178
Pisgah	275	275	1,775	275
Riverside East	1,192	1,192	1,562	1,650
San Bernardino-Lucerne	261	140	49	261
Tehachapi	3,489	3,491	4,446	4,151
Non-CREZ — Northern	33	12	12	34
Non-CREZ — Western LA	-	2	2	2
Distributed Generation	939	3,199	500	926
TOTAL	7,252	8,551	9,373	7,538

Table 4.8-2 Distributed generation modeled to meet the 33% RPS net short

Deliverability Area	Base Portfolio	Environmentally Constrained	Trajectory	Time Constrained
Northern	169	695	45	154
North of Lugo	133	267	100	100
East of Lugo	-	20	-	-
Eastern	58	271	-	20
Western LA	388	1,243	275	466
Eastern LA	191	704	80	185
TOTAL	939	3,199	500	926

Table 4.8-3 New Renewable generation output in SCE areas

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Base	7252	4395	6142
Environmental	8551	3104	8341
Trajectory	9373	5091	8077
Time Constrained	7538	3279	7262

Previously Identified Renewable Energy-Driven Transmission Projects

Several transmission projects that were identified in the SCE area in previous transmission planning processes to interconnect and deliver renewable generation have been included in the base cases for all portfolios. Following is a list of the projects in the SCE area along with a brief description.

Eldorado-Ivanpah Project

The project includes a new 220/115 kV substation in San Bernardino county and a 35-mile transmission line upgrade between the new substation and the Eldorado substation. The project has LGIA and CPUC approval, and construction is expected to begin in the first quarter of 2012. The proposed in-service date is 2013.

Valley-Colorado River Project

The project includes the following: a new Colorado River 500/220 kV Substation near Blythe; a new Red Bluff 500/220 kV Substation near Desert Center; a new Devers-Valley #2 500 kV transmission line; a new Devers-Red Bluff 500 kV transmission line; and a new Red Bluff-Colorado River 500 kV transmission line. The project has ISO and CPUC approval. The proposed in-service date is 2013.

West of Devers Project

The project involves rebuilding the four existing 220 kV transmission lines west of Devers with high capacity conductors. The project has LGIA and pre-licensing activities are underway. The proposed in-service date is 2017.

Tehachapi Renewable Transmission Project
The project includes the new Whirlwind 500 kV Substation, new 500 kV and 220 kV transmission lines and upgrading existing 220 kV and 66 kV lines. The project has ISO and CPUC approval. The proposed in-service date is 2015.

Cool Water-Lugo (South of Kramer) Project
The project includes approximately 60-70 miles of new 220 kV and 500 kV transmission lines and the siting of a future Desert View Substation east of the city of Apple Valley. The project has LGIA and pre-licensing activities are underway. The proposed in-service date is 2018.

Devers-Mirage 230 kV Lines Upgrade
The project consists of SCE's portion of the Path 42 Project, which includes upgrading the Coachella-Devers 230 kV transmission line, reconductoring the Devers-Mirage 230 kV transmission line and upgrading the Ramon-Mirage 230 kV transmission line. The project has ISO approval and engineering work is currently underway. The proposed in-service date is 2013.

Jasper Substation Project
The project involves construction of a new 220 kV substation in Lucerne Valley. The project has an LGIA. The proposed in-service date is 2013.

4.8.2 Study Results and Discussion

Following is a summary of the study results identifying facilities in the SCE area that did not meet system performance requirements. System performance concerns that were identified and mitigated in the reliability assessment are not presented in this section unless the degree of the system performance concern has materially increased. The discussion includes proposed mitigation plans for the system performance concerns identified.

Thermal Overloads

Holgate-Kramer 115 kV line
The Holgate-Kramer 115 kV line was overloaded under normal conditions with all facilities in service. The overloading occurred only in the environmentally constrained portfolio and is caused by distributed generation connected to the Holgate Substation. The line is a radial line serving two existing generators. Upgrading the capacity of the line would be required to depending on distributed generation development in the area.

Control 115/55 kV #1 and #2 Transformers
These transformers were overloaded following a T-1 outage involving either transformer. The overloading occurred only in the environmentally constrained portfolio and is caused by distributed generation connected to the substation. A new SPS, which curtails generation in the Control 55 kV system, would be required to address the loading concern. Another alternative is to upgrade the transformation capacity at the substation depending on distributed generation development in the area.

Inyokern-Kramer #3 115 kV line

The Inyokern-Kramer #3 115 kV line was overloaded following an L-1 outage involving the parallel Inyokern-Kramer-Randesburg #1 line. The overload occurred only in the environmentally constrained portfolio because of increased generation at and north of Inyokern. The existing Kramer 115 kV RAS mitigates this loading concern. Another alternative is to add a 230/115 kV transformer at Inyokern and loop the nearby Kramer-BLM West 230 kV line into the substation. In addition to addressing the loading issue, this development resulted in a substantial reduction in transmission losses in all scenarios under the conditions studied. As a result, the development was selected as a good candidate for further economic assessment. Results of the economic assessment are provided in Section 5.

Inyokern-Kramer-Randesburg #1 and #3 lines

An L-2 outage involving these lines resulted in voltage collapse or overloading in all portfolios. Modifying the Kramer 115 kV RAS to include the contingency will be required. Alternatively, the Inyokern 230 kV development described earlier can address this system performance concern as well.

Lugo 500/230 kV #1 and #2

The Lugo transformers were overloaded following a T-1 outage involving either transformer. The overload occurred in all four portfolios, but is highest in the base portfolio because of the amount of renewable generation in the North of Lugo area that is included in that portfolio. No further mitigation is considered, as the existing High Desert RAS mitigates the loading concern.

Barre-Ellis 230 kV line

The loading on the Barre-Ellis line reached or exceeded its rating following a G-1/L-1 contingency involving Imperial Valley-North Gila 500 kV and one San Onofre unit. The loading concern occurred in all scenarios with the exception of the base portfolio. Additionally, the line was overloaded in all portfolios following an L-2 outage involving the San Onofre-Santiago 230 kV lines. The L-2 loading concern is also identified in the reliability assessment results presented in Section 2. The proposed reliability project involving looping of the Del Amo-Ellis 230 kV line into Barre addresses the loading concern.

Voltage Issues

Voltage and Voltage Deviation Concerns

Voltage at Redbluff and Colorado River 500 kV buses exceeded the applicable high voltage limit of 1.05 p.u. or 525 kV under normal conditions in all four portfolios. SCE proposed an exemption for these buses from the voltage standard for normal conditions in the ISO Planning Standards and instead proposed using a high voltage limit of 550 kV or 1.1 p.u. The ISO has accepted this exemption.

Voltage deviation at the Inyokern 115 kV bus exceeded 5 percent following an L-1 contingency involving the Inyokern-Kramer 115 kV line in the environmentally constrained portfolio. The issue can be mitigated by modifying the Kramer RAS to include this contingency. The Inyokern 230 kV development discussed above can also address the voltage deviation. Another alternative is addition of a capacitor bank.

4.8.3 Conclusions

Several transmission reinforcement projects have been identified for the SCE system in previous transmission planning processes to interconnect and deliver renewable generation. These projects were included in the base cases used for the policy-driven power flow and stability studies performed for the SCE system. The results of the studies showed that the existing SCE transmission system along with those planned additions and upgrades is adequate to accommodate any of the four renewable generation portfolios without significant additional upgrades.

Some system performance issues requiring mitigation were identified in the environmentally constrained portfolio in particular, in the North of Lugo area. Upgrading the existing radial Holgate-Kramer 115 kV line is required to prevent congestion on the line under normal conditions. The other identified system performance concerns can be mitigated using existing, modified or new special protection schemes (SPS). Transmission alternatives to address the system performance concerns are also presented. In particular, development of a 230/115 kV transformer station at Inyokern was found to be an attractive alternative. In addition to improving system performance, this alternative resulted in a substantial reduction in transmission losses under the conditions studied. As a result, the alternative has been selected as a candidate for further economic evaluation.

According to ISO tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are included in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are included in the base case, but not in any of the stress scenarios or are included in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the SCE system did not identify any new transmission additions or upgrades that qualify as category 1 or category 2 elements.

4.9 Policy Driven Assessment Results and Mitigations in SDG&E Area

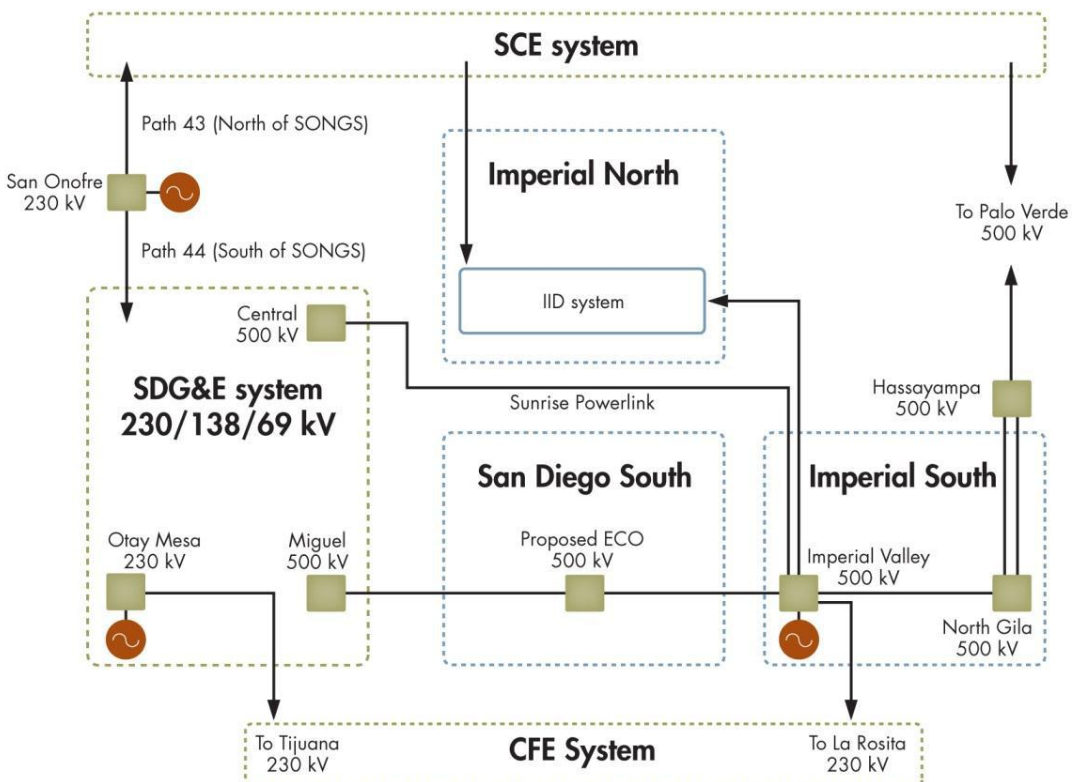
4.9.1 SDG&E System Overview

The SDG&E system configuration is shown in Figure 4.9-1. The major transmission upgrade in the SDG&E system modeled in the policy-driven assessment is the Sunrise Powerlink 500 kV transmission line and the associated plan of service. The ECO 500 kV Substation that the Imperial Valley-Miguel 500 kV line will loop into is also modeled in the base cases.

The points of import in 2021 will be the South of San Onofre (SONGS) transmission path (WECC Path 44), the Miguel 500/230 kV Substation, Suncrest 500/230kV Substation and the Otay Mesa-Tijuana 230 kV transmission line.

There are four CREZs in the east that have a direct impact on the SDG&E system. San Diego South and Imperial South CREZs are shown in Figure 4.9-1. Imperial North-A and Imperial North-B are located inside IID territory.

Figure 4.9-1: Illustration of San Diego area



The following table shows the renewable generation levels modeled in the San Diego area in all four portfolios.

Table 4.9-1: Summary of renewable generation in the San Diego area

Zone	Renewable Generation by Portfolio (MW)			
	Base	Environmental	Time	Trajectory
Imperial – SDGE	404	400	535	-
Imperial – IID	1,289	239	667	-
San Diego South	699	108	400	400
Non-CREZ – SDGE	-	6	6	3

The following table shows the renewable generation by portfolios in the San Diego area.

Table 4.9-2: Summary of renewable generation in the San Diego area

Portfolio	Renewable Capacity 9MW)	Output on peak (MW)	Output off-peak (MW)
Base	1,208	516	996
Environmental	916	301	862
Trajectory	993	348	776
Time Constrained	484	116	456

4.9.2 Study Results and Discussion

Power flow assessment, post transient studies and stability assessments were carried out for all four portfolios. Transient stability assessments demonstrated acceptable system performance for all the major contingencies. The following sections provide an overview of thermal and voltage issues, and corresponding mitigations in the San Diego area.

Thermal Issues

Normal Overloads in Environmental Portfolio

Fourteen thermal overloads were observed under normal (N-0) operating conditions. These overloads were observed only in the environmentally constrained portfolio. The following facilities exhibited overloads under peak and off-peak conditions. These are also listed as part of Appendix C.

Peak condition:

- Borrego-Narrows 69 kV
- Narrows-Warners 69 kV
- El Cajon-Los Coches 69 kV
- Granite-Granite tap 69 kV

Off-peak condition:

- Barrett-Cameron 69 kV
- Barrett-Loveland 69 kV
- Cameron Tap-Glencliff Tap 69 kV
- Loveland-Descanso 69 kV
- Loveland-Alpine 69 kV
- Descanso-Glencliff Tap 69 kV
- Santa Ysabel-Creelman 69 kV
- Warren Canyon-Warren Canyon Tap 69 kV
- Borrego-Narrows 69 kV
- Narrows-Warners 69 kV
- Warners-Rincon 69 kV
- Warners-Santa Ysabel 69 kV

The El Cajon-Los Coches 69 kV overload was also observed in the reliability assessment. A reliability project to reconductor this line has been approved, and it will mitigate the overloads observed in the policy-driven assessment. All the overloads are caused by distributed generation modeled in the eastern and northeastern 69 kV system of SDG&E. Following are the potential mitigations to eliminate these overloads:

- individual line reconductoring;
- 138 kV conversion of this entire 69 kV system; and
- generation curtailment.

These mitigations are dependent on the extent of and location of distributed generation that materializes in this area.

Thermal Overloads under Contingency Condition

The following facilities were observed to be overloaded under contingency conditions. A detailed results table is included in Appendix C.

TL631 El Cajon-Los Coches 69 kV line

This line exhibits an overload for the contingency of TL632, Granite-Miguel-Los Coches 69 kV line in the time-constrained and environmentally constrained portfolios under peak load conditions. A reliability upgrade to reconductor this line (recommended in Chapter 2) would eliminate the overload caused by additional renewable generation.

TL658 Sampson-Division 69 kV line

This line exhibits an overload for the contingency of TL23026, Silvergate-Bay Boulevard 230 kV line in the time-constrained and base portfolios under peak load conditions. A potential mitigation for this overload is the Miguel Tap reconfiguration. This would create the Bay Boulevard-Miguel 230 kV line, two Otay Mesa-Miguel 230 kV lines and an additional Miguel-Sycamore 230 kV line. Since the Miguel Tap reconfiguration project is needed for Cluster 1 and 2 generation, it is the preferred mitigation for this issue. Another alternative would be to reconductor the line.

TL642B Sweetwater-Montgomery Tap and TL603B Sweetwater-Sweetwater Tap 69 kV lines

Both of these lines exhibit overloads for the same contingency mentioned above: TL23026, Silvergate-Bay Boulevard 230 kV line in the base and trajectory portfolios under peak load condition. These overloads are also observed in the reliability assessment in 2021, and future evaluation is recommended. Potential mitigations are reconfiguring Miguel Tap or reconductoring these lines.

TL6916 Sycamore-Scripps 69 kV line

This line exhibits an overload for the contingency of TL23042A, Otay Mesa-Bay Boulevard 230 kV line in the base portfolio under peak load conditions. Potential mitigations are reconfiguring Miguel Tap or reconductoring this line.

TL13820 Sycamore-Chicarita 138 kV line

This line shows up as overloaded for the contingency of Encina 230/138 Bank 60 in all four portfolios under peak load conditions. This overload is caused by the potential retirement of the Encina generation. If any generation materializes in Encina area, then this overload would be eliminated. In case no generation is available at Encina, a potential mitigation for this issue would be to reconductor this line.

Cameron-Cameron Tap 69 kV line

This line exhibits an overload for the contingency of the Loveland-Barrett 69 kV line in the environmentally constrained portfolio under off-peak load conditions. The overload is caused by distributed generation in this area. Potential mitigation is to reconductor the line or curtail generation.

Boulder Creek Tap-Descanso 69 kV line

This line exhibits an overload for the contingency of the Santa Ysabel-Creelman 69 kV line in the environmentally constrained portfolio under off-peak load conditions. The overload is caused by distributed generation in this area. Potential mitigation is to reconductor the line or to curtail generation.

Boulder Creek Tap-Santa Ysabel 69 kV line

This line exhibits an overload for the contingency of the Descanso-Loveland 69 kV line in the environmentally constrained portfolio under off-peak load conditions. The overload is caused by distributed generation in this area. Potential mitigation is to reconductor the line or to curtail generation.

Descanso-Glencliff Tap 69 kV line

This line exhibits an overload for the contingency of the Loveland-Barrett 69 kV line in the environmentally constrained and time-constrained portfolios under off-peak load conditions. The overload is caused by distributed generation in this area. Potential mitigation is to reconductor the line or to curtail generation.

Los Coches-Alpine 69 kV line

This line exhibits an overload for the contingency of the Loveland-Los Coches 69 kV line in the environmentally constrained portfolio under off-peak load conditions. The overload is caused by distributed generation in this area. Potential mitigation is to reconductor the line or curtail generation.

El Cajon-Los Coches 69 kV line

This line exhibits an overload for the contingency of the El Cajon-Granite-Jamacha 69 kV line in the environmentally constrained and time-constrained portfolios under off-peak load conditions. A reliability upgrade to reconductor this line (recommended in Chapter 2) will eliminate the overload issue.

Voltage Issues

Numerous voltage-related issues are observed under peak and off-peak conditions. These include high voltages under normal operation, voltage deviations and reactive power deficiency. Results pertaining to voltage performance are included in Appendix A.

High Voltages

Voltages above 1.05 p.u. are observed across SDG&E system under normal (N-0) conditions (listed in Appendix C) at several buses, predominantly on the 69 kV system. Most of these are under off-peak conditions. The primary cause for these high voltages is distributed generation modeled throughout the system. A potential mitigation for this issue is to require power factor control for DGs. In addition to power factor control, reactors may need to be installed at certain locations across the 69kV system.

Voltage Deviations

Voltages above 1.05 p.u. are observed across SDG&E system under normal (N-0) conditions (listed in Appendix C) at several buses, predominantly on the 69 kV system. Most of these are under off-peak conditions. The primary cause for these high voltages is distributed generation modeled throughout the system. A potential mitigation for this issue is to require power factor control for DGs. In addition to power factor control, reactors may need to be installed at certain locations across the 69kV system.

Voltage Collapse

Post transient voltage stability was tested for several contingencies. Following is the summary of post transient results for the San Diego area.

Table 4.9-3: Summary of post transient study and voltage deviations

	Portfolio			
Worst Contingency	Base	Environmental	Time	Trajectory
IV-ECO 500 kV (L-1)	Deviation >5%	Deviation >5%	Deviation >5%	Deviation >5%
ECO-Miguel 500 kV (L-1)	Deviation >5%	Deviation >5%	Deviation >5%	Deviation >5%
IV-ECO 500kV and IV-Suncrest 500 kV Lines (L-2)	Deviation <10%	Deviation <10%	Deviation <10%	Deviation <10%
Otay Mesa + ECO-Miguel (L-1/G-1)	Voltage Collapse	Deviation >5%	Deviation >5%	Deviation >5%
SONGS-g2 (n-2)	Deviation <10%	Deviation <10%	Deviation <10%	Deviation <10%

Post transient studies identified voltage instability following the L-1/G-1 outage of *Otay Mesa generation* and *Southwest Powerlink (Eco-Miguel 500kV line)*. This contingency resulted in voltage collapse in the base portfolio, and voltage deviations greater than 5 percent in the remaining three portfolios. Other contingencies that resulted in voltage deviations greater than 5 percent are as follows:

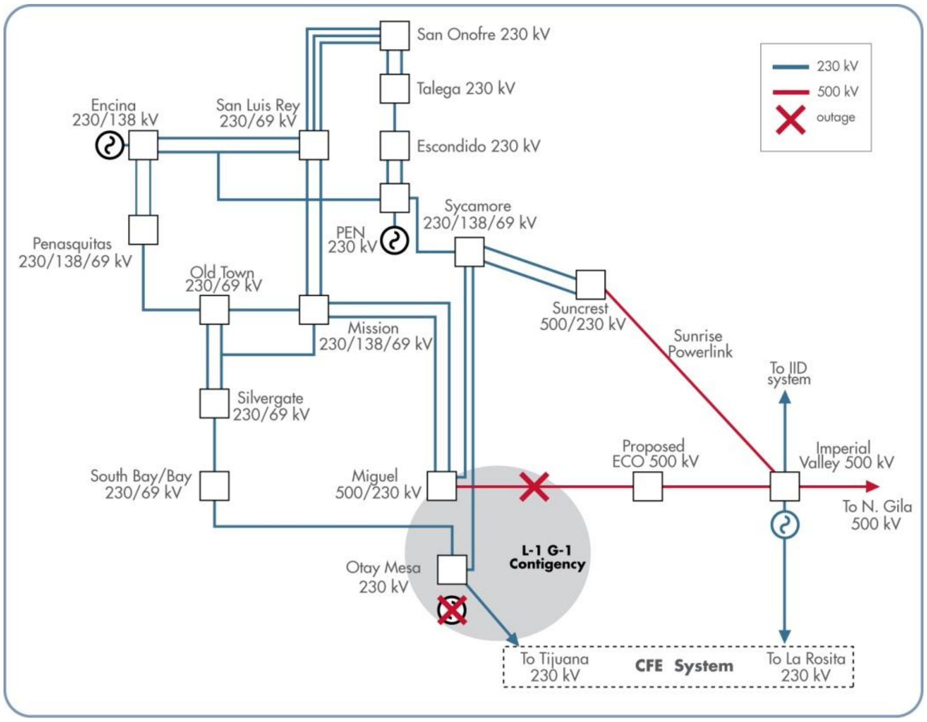
- Imperial Valley-ECO 500 kV line (N-1);
- ECO-Miguel 500 kV line 9 (N-1); and
- Southwest Power Link + Sunrise Power Link (N-2).

The first two contingencies are assumed to trigger an SPS to drop generation at Imperial Valley and to cross-trip the lines connecting the SDG&E and CFE systems (Imperial Valley-La Rosita 230kV line in the winter and Otay Mesa-Tijuana 230kV line in the summer).

N-2 outage of Southwest Power Link plus Sunrise Powerlink (Imperial Valley-Eco 500 kV line and Imperial Valley-Suncrest 500 kV line) resulted in voltage deviations smaller than 10 percent, which is an acceptable system performance. Up to 400 MW of automatic load shedding was assumed for this N-2 contingency. G-2 outage of two SONGS units also resulted in voltage deviations that were smaller than 10 percent.

The worst contingency is the L-1/G-1 outage of Otay Mesa generation and Southwest Powerlink (Miguel-ECO 500kV line). This contingency is depicted in Figure 4.9-2.

Figure 4.9-2: Worst contingency resulting in voltage collapse



In the base and trajectory portfolios, about 2,000 MW of internal San Diego generation was dispatched, and an additional 500 MVar of dynamic reactive support was required to mitigate voltage instability issues. In the environmentally constrained and time-constrained portfolios, about 1,650 to 1,750 MW of internal San Diego generation was modeled, and an additional 400 MVar of dynamic reactive support was required to mitigate voltage instability issues. A summary of San Diego imports, loop flow through CFE, internal San Diego generation and reactive support requirement is presented in the following table.

Table 4.9-4: San Diego area loads, generation and flow summary

	Base	Environmental	Time	Trajectory
SDG&E Load + Losses (MW)	5,488	5,492	5,483	5,487
San Diego Import (MW)	3,530	3,715	3,790	3,500
Loop Flow Through CFE System (MW)	585	561	565	543
Internal San Diego Gen (MW)	2,000	1,750	1,650	2,000
Approx. Reactive Support Requirement (MVar)	500	400	400	500

All Encina units were assumed to be retired in all four portfolios. The most effective locations for installing reactive support were identified to be Sycamore and Mission. Reactive support required in the environmental and time-constrained portfolio is less than the remaining two portfolios because of higher South of SONGS (Path 44) flow. Higher imports from the North create a less stressed condition in the San Diego area as compared to higher imports from the East.

A sensitivity study with an additional 400 to 500 MW of internal generation in the San Diego area resulted in a reduction of reactive support requirements. The following two scenarios were considered:

1. sensitivity 1 — 300 MW at Otay + 100 MW at Miguel-Mission line; and
2. sensitivity 2 — 500 WM at Encina.

The following table summarizes the results for these sensitivities.

Table 4.9-5: Reactive support requirement sensitivity

Sensitivity Case	Generation	Reactive Support Requirement
Base	No additional generation. Encina retired	500 MVar at Mission and Sycamore
Sensitivity 1	Additional 300 MW at Otay + 100 MW at Miguel-Mission line	120 to 150 MVar at Mission
Sensitivity 2	Additional 500 MW at Encina	120 to 150 MVar at Mission

The exact amount and location of reactive support will depend upon the size and location of additional generation. Therefore, although the reactive support requirement is evident in all four portfolios, the lead time for installing synchronous condensers allows for decision deferment depending on generation development in the San Diego area over the next few years.

4.9.3 Conclusions

In the environmentally constrained portfolio, several normal overloads (N-0) were observed on the 69 kV system. This is primarily because of distributed generation assumptions in the portfolio. If all the distributed generation do materialize, the eastern 69 kV system will need to be reconductored or a way to curtail generation will need to be determined. This distributed generation also resulted in high voltages in some parts of the system and may require an ability to regulate voltages.

Overloads caused in the Sweetwater and the Sycamore-Scripps areas under peak load conditions can be mitigated by Miguel Tap reconfiguration, which is the preferred mitigation and is needed for Cluster 1 and 2 generation. Overloads on El Cajon-Los

Coches 69 kV line will be mitigated by reconductoring this line. Overloads in the eastern 69 kV system during off-peak conditions are caused by distributed generation and can be mitigated by reconductoring the lines or by curtailing generation.

Voltage instability problems observed for the L-1/G-1 contingency of Otay Mesa generation and Southwest Powerlink (Miguel-ECO 500 kV line) can be mitigated by installing dynamic reactive support at Mission and Sycamore. The load time for installing additional reactive support allows for decision deferment, depending upon the location and size of generation development in the San Diego area over the next few years.

According to ISO section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are included in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are included in the base case, but which are not included in any of the stress scenarios or are included in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Accordingly, the results of the policy-driven assessment for the SDG&E system did not identify any new transmission additions or upgrades that qualify as category 1 or category 2 elements.

4.10 Testing Deliverability For Portfolios

An assessment was performed to verify the deliverability of the renewable resources modeled in the base portfolio for resource adequacy purposes. The objectives of the deliverability assessment are as follows:

- Model the target expanded maximum import capability (MIC) for each intertie to support deliverability for the MW amount of resources within each intertie in the base portfolio.
- Determine the deliverability of the new renewable resources in the base portfolio located within the ISO balancing authority.
- Identify network upgrades needed to support full deliverability of the new renewable resources and the target expanded MIC.

4.10.1 Deliverability Assessment Methodology

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf). The main steps of the deliverability assessment are described below.

4.10.1.1 Master Deliverability Assessment Base Case

A master base case was developed for the on-peak deliverability assessment, which modeled all the generating resources in the base portfolio. The resources in the master base case were dispatched as follows:

- Existing capacity resources were dispatched at 80 percent of summer peak net qualified capacity (NQC).
- New resources were dispatched to balance load and maintain expected imports, but not to exceed 80 percent of summer peak NQC.
- Imports are at the maximum summer peak simultaneous historical level by branch group. The historically unused existing transmission contracts crossing control area boundaries were modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts. For any intertie that requires expanded MIC, the import is the target expanded MIC value.
- Non-pump load is at the 1-in-5 peak load level for ISO.

Pump load is dispatched within expected range for summer peak load hours.

4.10.1.2 Group Deliverability Assessment Base Cases

Based on engineering knowledge of the transmission system constraints, the generating resources were grouped electrically. One group base case was developed from the master base case for each group by dispatching all generating resources in the group to 80 percent of the NQC. New generation in groups that are not the focus of the group base case was dispatched at zero initially, but available to be turned on during the analysis.

4.10.1.3 Screening for Potential Deliverability Problems

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn consisting of all generating units including unused existing transmission contract injections that fall within 5 percent or more of the distribution factor (DFAX) region. These are expressed as follows:

- DFAX = (change in flow on the analyzed facility / change in output of the generating unit) *100 percent *or*
- Flow impact = (DFAX * NQC / applicable rating of the analyzed facility) *100 percent; where NQC represents the net capacity of a generating unit

Load flow simulations were performed, which study the worst-case combination of generator output within each 5 percent circle.

4.10.1.4 Verifying and Refining Analysis

The outputs of capacity units in the 5 percent circle were increased starting with units with the largest impact on the transmission facility. No more than 20 units were increased to their maximum output. In addition, no more than 1,500 MW of generation was increased. All remaining generation within the ISO balancing authority was proportionally displaced to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased by more than 1,500 MW, the impact of the remaining amount of generation to be increased was considered using a facility loading adder. This adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the adder, up to 20 units. If the net impact from the adder was negative, the impact was set to zero and the flow on the analyzed facility without applying adders was reported.

4.10.2 Deliverability Assessment Assumptions

The base portfolio power flow peak case was used for the deliverability assessment. The dispatch was adjusted based on the deliverability assessment methodology described above. Some key assumptions of the cases are described below.

Transmission

The same transmission system as in the base portfolio power flow peak case was modeled.

Load Modeling

A coincident 1-in-5-year heat wave in the ISO load was modeled in the base case.

Generation Capacity (Pmax) in the Base Case

For existing thermal generating units, the most recent summer peak NQC was used as Pmax. For new thermal generating units, Pmax is the installed capacity in the base portfolio. Initially, wind and solar generation Pmax data were set to 20 percent exceedance production levels during summer peak load hours. If the study identified 20 or more non-wind generation units in the group (i.e., 5 percent DFAX circle), wind and solar generations were assessed for 50 percent exceedance production levels.

Table 4.10-1: Wind and solar generation exceedance production levels (% of installed capacity) in deliverability assessment

	20% Exceedance		50% Exceedance	
	Northern California	Southern California	Northern California	Southern California
Wind	51%	64%	28%	40%
Solar	100%	100%	85%	85%

Import Levels

Table 4.10-2 shows the import megawatt amount modeled on the given branch groups.

Table 4.10-2: Deliverability assessment import target

Branch Group (BG) Name	BG Import Direction	Net Import MW	Import Unused ETC MW
VICTVL_BG	N-S	1,138	171
COI_BG	N-S	3,770	548
BLYTHE_BG	E-W	107	0
CASCADE_BG	N-S	1	0
CFE_BG	S-N	-55	0
ELDORADO_BG	E-W	1,158	0
IID-SCE_BG	E-W	1,000	0
IID-SDGE_BG	E-W	500	0
INYO_BG	E-W	0	0
LAUGHLIN_BG	E-W	0	0
MCCULLGH_BG	E-W	30	316
MEAD_BG	E-W	469	505
MERCHANT_BG	E-W	439	0
N.GILABK4_BG	E-W	-140	168
NOB_BG	N-S	1,469	0
PALOVRDE_BG	E-W	3,139	175
PARKER_BG	E-W	108	27
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	0	0
SYLMAR-AC_BG	E-W	0	471

4.10.3 Sensitivity Deliverability Assessments

To evaluate the impact of generation retirement resulting from state environmental policies, such as OTC, on the deliverability of the generating resources, a sensitivity deliverability assessment was performed with generation assumptions different from 4.10.2. The minimum OTC generation was dispatched in the master base case as follows: SCE area 2,200 MW and San Diego area 0 MW. In PG&E area, there is no minimum OTC generation identified. Please see section 3.3 for details on the OTC assumptions. In the San Diego area, 400 MW of additional new generation was added. All the OTC generators initially dispatched or not, are available to be dispatched to full output in the study in the SCE and PG&E areas. For the SDG&E area, the additional 400 MW were a replacement for the OTC generation, therefore, the SDG&E area OTC generation was not available to be dispatched in this study.

4.10.4 Deliverability Assessment Results

4.10.4.1 PG&E Area Results

Table 4.10-3: Base portfolio deliverability assessment results for the Humboldt area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Bridgeville-Garberville 60 kV line	Normal	108 %	Humboldt area DG and Non CREZ	24 MW	Rerate/reconductor or new line
Humboldt-Maple Creek 60 kV line	Humboldt-Trinity 115 kV Line	101 %	Humboldt area DG	2 MW	Rerate/reconductor or SPS to trip Humboldt area generation
Humboldt-Trinity 115 kV line	Bridgeville-Cottonwood 115 kV Line	112 %	Humboldt area DG	14 MW	Rerate/ reconductor or SPS to trip Humboldt area generation

The deliverability of the new renewable resources modeled in the Humboldt area is most limited by normal overload on the Bridgeville-Garberville 60 kV line. This overload can be mitigated by the new Bridgeville-Garberville 115 kV line proposed to address reliability needs in the Humboldt area. Other constraints identified in the Humboldt area are overloads on the Humboldt-Maple Creek 60 kV and Humboldt-Trinity 115 kV lines under N-1 conditions. These overloads can be mitigated by using SPS to trip Humboldt area generation. All of the Humboldt deliverability upgrades identified represent local area upgrades that are dependent on particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

Table 4.10-4: Base portfolio deliverability assessment results for the North Coast area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Hopland 115/60 kV bank	Geysers #3-Eagle Rock 115 kV Line and Geysers #17	107%	Non CREZ – North Coast	38 MW	Rerate or SPS to trip North Coast area generation
Eagle Rock-Cortina 115 kV line	Eagle Rock-Fulton-Silverado and Fulton-Pueblo 115 kV Lines	133%	Non CREZ – North Coast	114 MW	SPS to trip North Coast area generation
Fulton-Calistoga 60 kV line	Eagle Rock-Fulton-Silverado 115 kV and Geysers #9-Lakeville 230 kV Lines	121%	Non CREZ – North Coast	83 MW	SPS to trip North Coast area generation
Fulton-Hopland 60 kV line	Eagle Rock-Fulton-Silverado 115 kV and Geysers #9-Lakeville 230 kV Lines	136%	Non CREZ – North Coast	92 MW	SPS to trip North Coast area generation
Middletown-Calistoga 60 kV line	Eagle Rock-Fulton-Silverado 115 kV and Geysers #9-Lakeville 230 kV Lines	151%	Non CREZ – North Coast	154 MW	SPS to trip North Coast area generation

The deliverability of the new renewable resources modeled in the North Coast area is most limited by N-2 overload on the Middletown-Calistoga 60 kV line. This overload can be mitigated by using SPS to trip Eagle Rock area generation. Other constraints identified in the North Coast area are: overloads on the Hopland 115/60 kV bank under N-1 contingency and Eagle Rock-Cortina 115 kV, Fulton-Calistoga 60 kV line and Fulton-Hopland 60 kV lines under N-2 conditions. These overloads can also be mitigated by using SPS to trip Eagle Rock area generation. All of the North Coast deliverability upgrades identified represent local area upgrades that are dependent on the particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

Table 4.10-5: Base portfolio deliverability assessment results for the North Valley area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Caribou 230/115 kV bank #11	Normal	106%	North Valley area DG	6 MW	Rerate or replace bank
Malacha 230/115 kV bank #2	Normal	104%	North Valley area DG	1 MW	Rerate or replace bank
Coleman-Red Bluff 60 kV line	Coleman-Cottonwood 60 kV line	115%	North Valley area DG	9 MW	SPS to trip North Valley area generation

The deliverability of the new renewable resources modeled in the North Valley area is most limited by N-1 overload on the Coleman-Red Bluff 60 kV line. This overload can be mitigated by using SPS to trip Coleman area generation. Other constraints identified in the North Valley area are the normal overloads on the Caribou 230/115 kV bank #11 and Malacha 230/115 kV bank #2. These overloads can be mitigated by replacing the overloaded banks. All of the North Valley deliverability upgrades identified represent local area upgrades that are dependent on the particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

Table 4.10-6: Base portfolio deliverability assessment results for the Solano area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Cayetano-N. Dublin 230 kV line	Contra Costa-Las Positas and Moraga-Castro Valley 230 kV Lines	111%	Solano CREZ	454 MW	Rerate or SPS to trip Solano area generation
Lone Tree-USWP-JRW 230 kV line	Contra Costa-Las Positas and Moraga-Castro Valley 230 kV lines	109%	Solano CREZ	404 MW	Rerate or SPS to trip Solano area generation

The deliverability of the new renewable resources modeled in the Solano area is most limited by N-2 overload on the Cayetano-North Dublin 230 kV line. This overload can be mitigated by using SPS to trip Solano or Contra Costa area generation. Other constraint identified in the North Coast area is a N-2 overload on the Lone Tree-USWP-JRW 230 kV line. This overload can also be mitigated by using SPS to trip Solano or Contra Costa area generation. These overloads were also identified in all years of the operational deliverability assessments. Therefore, these overloads are existing problems that need to be addressed through the TPP, and the ISO recommends that PG&E move forward with the recommended mitigation to be placed in-service by summer 2013.

Table 4.10-7: Base portfolio deliverability assessment results for the Greater Bay area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Parks Tap 60 kV line	Normal	142%	Mission area DG	6 MW	Reconductor the overloaded section
Herdlyn 70/60 kV bank	Contra Costa-Balfour 60 kV line	130%	Diablo area DG	11 MW	SPS to trip Diablo area generation

The deliverability of the new renewable resources modeled in the Bay area is most limited by N-1 overload on the Herdlyn 70/60 kV bank. This overload can be mitigated by using SPS to trip Diablo area generation. Other constraint identified in the Bay area is a normal overload on the Parks Tap 60 kV line. This overload can be mitigated by reconductoring the overloaded line section. All of the Bay area deliverability upgrades identified represent local area upgrades that are dependent on the particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

Table 4.10-8: Base portfolio deliverability assessment results for the Central Valley area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Donnell-Curtis 115 kV line	Normal	112%	Stanislaus area DG	12 MW	Rerate or reconductor the overloaded section
Pease 115/60 kV bank	Table Mountain-Pease 60 kV line	106%	Sierra area DG	3 MW	SPS to trip Sierra area generation

The deliverability of the new renewable resources modeled in the Central Valley area is most limited by a normal overload on the Donnell-Curtis 115 kV line. This overload can be mitigated by reconductoring the overloaded line section. Other constraint identified in the Central Valley area is a N-1 overload on the Pease 115/60 kV bank. This overload can be mitigated by using SPS to trip Curtis area generation. All of the Central Valley deliverability upgrades identified represent local area upgrades that are dependent on the particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

Table 4.10-9: Base portfolio deliverability assessment results for the Greater Fresno area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Helm 230/70 kV bank #1	Normal	105%	Fresno and Yosemite area DG	8 MW	Rerate or replace the bank
Kern-Lerdo-Kern Oil 115 kV line	Normal	112%	Fresno and Kern area DG	20 MW	Reconductor the overloaded line section
Mendota-San Joaquin-Helm 70 kV line	Normal	230%	Yosemite area DG	61 MW	Reconductor the overloaded line section
Kern-Live Oak 115 kV line	Kern-Magunden-Witco 115 kV line	122%	Fresno and Kern area DG	53 MW	SPS to trip Fresno and Kern area generation
Panoche-Oro Loma 115 kV line	Panoche-Mendota 115 kV line and Exchequer	103%	Fresno area DG	20 MW	Rerate or SPS to trip Fresno area generation
Warnerville-Cottle B 230 kV line	Bellota-Melones 230 kV line	105%	Greater Fresno area DG	346 MW	SPS to trip Greater Fresno area generation

The deliverability of the new renewable resources modeled in the Greater Fresno area is most limited by N-1 overload on the Warnerville-Cottle B 230 kV line. This overload can be mitigated by using SPS to trip Fresno area generation. This line was also identified to be overloaded in all years of the operational deliverability study. Therefore, this line overload is an existing problem that needs to be addressed through the TPP, and the ISO recommends that PG&E move forward with the recommended mitigation to be placed in-service by summer 2013.

Other constraints identified in the Greater Fresno area are normal overloads on the Helm 230/70 kV bank #1, Kern-Lerdo-Kern Oil 115 kV line and Mendota-San Joaquin-Helm 70 kV line as well as N-1 overloads on the Kern-Live Oak 115 kV line and

Panoche-Oro Loma 115 kV line. The overload on the Helm 230/70 kV bank can be mitigated by replacing the bank. The overloads on the Kern-Lerdo-Kern Oil 115 kV and Mendota-San Joaquin-Helm 70 kV lines can be mitigated by reconductoring the overloaded sections. Other than the N-1 overload on the Warnerville-Cottle B 230 kV line, all of the remaining Central Valley deliverability upgrades identified represent local area upgrades that are dependent on the particular generation project locations. In addition, these upgrades all have lead times expected to be less than three years. These types of localized short lead-time upgrades can be identified and funded through GIP, and therefore are not recommended for further consideration in this TPP cycle.

A sensitivity assessment was performed by incorporating the OTC study results. The study results are listed in Table 4.10-10. An additional deliverability constraint of a normal overload on the Cayetano-USWP 230 kV line was identified in the Solano area. The ISO recommends that PG&E move forward with rerating the Cayetano-USWP-JRW 230 kV line identified below, by summer 2013. Also, the previously identified overloads on the Cayetano-N. Dublin and Lone Tree-USWP-JRW 230 kV lines are exacerbated.

Some of the deliverability constraints in the Greater Fresno area were found to be relieved in the sensitivity assessment. In particular, the overloads on the Panoche-Oro Loma 115 kV and Warnerville-Cottle B 230 kV lines were eliminated.

The results in the other areas within PG&E system remain unchanged.

Table 4.10-10: Sensitivity deliverability assessment results for the PG&E (Solano) area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Cayetano-USWP-JRW 230 kV line	Normal	109%	Solano CREZ	247 MW	Rerate
Cayetano-N. Dublin 230 kV line	Contra Costa-Las Positas and Moraga-Castro Valley 230 kV Lines	114%	Solano CREZ	535 MW	Rerate or SPS to trip Solano area generation
Lone Tree-USWP-JRW 230 kV line	Contra Costa-Las Positas and Moraga-Castro Valley 230 kV Lines	113%	Solano CREZ	496 MW	Rerate or SPS to trip Solano area generation

4.10.4.2 SCE Area Results

No deliverability constraint is identified on the ISO-controlled grid in the SCE area. The transmission as modeled is sufficient to provide the deliverability for the renewable resources in the base portfolio.

A sensitivity assessment was performed to evaluate the base portfolio deliverability without Pisgah 500 kV upgrades. The scope of Pisgah 500 kV upgrades include the following: expanding the existing Pisgah 230 kV Substation to 500 kV; looping the Eldorado-Lugo 500 kV #1 line into the new Pisgah 500 kV Substation to form the Eldorado-Pisgah 500 kV #1 line and Lugo-Pisgah 500 kV #1 line; removing the existing Pisgah-Lugo 230 kV #1 line and building a new Lugo -Pisgah 500 kV #2 line. As shown in the table below the Lugo 500/230 kV transformer overloaded for the loss of the parallel transformer. Adding a third Lugo 500/230kV transformer could mitigate this overload. However, the Pisgah 500 kV upgrades are in executed LGIAs, and are required to be funded through that process if the associated generation proceeds to development. In addition, a third Lugo 500/230 kV transformer at Lugo has been identified as needed in the generation interconnection study process.. As a result, it is not necessary to consider the approval of the third Lugo 500/230 kV transformer any further in this planning cycle.

Table 4.10-11: Base portfolio deliverability assessment results without the Pisgah 500 kV upgrades

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Lugo 500/230 kV #1 or #2	Lugo 500/230 kV #2 or #1	118%	Pisgah San Bernardino-Lucerne Kramer	400 MW	Install the third Lugo 500/230kV transformer bank

Another sensitivity assessment was performed for minimum OTC generation. The study results are listed in table 4.10-12. Deliverability constraints were identified in the western LA Basin. For all the overloads identified, the OTC generating units are located on both sides of the constraints. Therefore, the assessment has identified the worse combinations of the OTC unit dispatch that could affect the deliverability of the existing and planned generating resources. An SPS to trip Redondo generation and La Fresa load under the loss of both La Fresa-Redondo 230 kV #1 and #2 lines could mitigate the overloads on the Hinson-La Fresa 230 kV line and the Hinson-Lighthipe 230 kV line. The overloads on the Alamitos-Lighthipe 230 kV line could be mitigated by the SCE proposed transmission project to loop the Del Amo-Ellis 230 kV line into the Barre Substation. Alternatively, an SPS tripping Alamitos generation is also effective in mitigating the overloads. However, the retirement and repowering plans of OTC generation have not been decided yet, so it is not necessary to further consider these mitigation plans in this planning cycle.

Table 4.10-12: Sensitivity deliverability assessment results for the SCE area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Hinson-La Fresa 230 kV #1	La Fresa-Redondo 230 kV #1 and #2	107%	Western LA Basin-Hinson/Lighthipe area	96 MW	SPS tripping Redondo generation and 50 MW load at La Fresa
Hinson-Lighthipe 230 kV #1	La Fresa-Redondo 230 kV #1 and #2	103%	Western LA Basin-Hinson/Lighthipe area	63 MW	SPS tripping Redondo generation
Alamitos-Lighthipe 230 kV #1	Alamitos-Center 230 kV #1	106%	Western LA Basin-East of Lighthipe	130 MW	SPS tripping Alamitos generation; or loop Del Amo-Ellis 230kV line into Barre substation
Alamitos-Lighthipe 230 kV #1	Barre-Ellis 230 kV #1	102%	Western LA Basin-East of Lighthipe	65 MW	

4.10.4.3 SDG&E Area Results

The results of the deliverability assessment in the San Diego area are contained the following table.

Table 4.10-13: Base portfolio deliverability assessment results for the San Diego area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Miguel Tap-Bay Boulevard 230 kV	Base case	102 %	Imperial-SDG&E, Imperial-IID	190 MW	Reconfigure TL23041 and TL23042 at Miguel Substation to create two Otay Mesa-Miguel 230 kV lines (C1C2 PhII pending LGIA)
Division-Sampson 69 kV	Silvergate-Bay Boulevard 230 kV	105 %	San Diego: existing-Border, Otay, Otay Mesa DGs-Imperial Beach, Otay, Paradise, San Ysidro, Jamacha	70 MW	
Montgomery Tap-Sweetwater 69 kV	Silvergate-Bay Boulevard 230 kV	129 %	San Diego: existing-Border, Otay, Otay Mesa DGs-Imperial Beach, Otay, San Ysidro	422 MW	
Sweetwater - Sweetwater Tap 69 kV	Silvergate-Bay Boulevard 230 kV	136 %	San Diego: existing-Border, Otay, Otay Mesa DGs-Imperial Beach, Otay, San Ysidro	472 MW	
Poway-Rancho Carmel 69 kV	Artesian-Sycamore 69 kV and Bernardo-Sycamore 69 kV	117 %	DG-Poway, Warren Canyon, Pomerado-Poway	0 MW	Reconductor line
Bernardo-Rancho Carmel	Artesian-Sycamore 69 kV and Bernardo-Sycamore 69 kV	102 %	DG-Poway, Warren Canyon, Pomerado-Poway	0 MW	Reconductor line

As shown in the table above, the San Diego area deliverability assessment identified a violation on the Miguel Tap-Bay Boulevard 230 kV line caused by the addition of renewable generation in the Imperial zone. The addition of this generation increases the loop-flow through the CFE system and creates an N-0 overload. This overload can be mitigated by reconfiguring TL23041, Otay Mesa-Miguel Tap-Sycamore 230 kV, and TL23042, Otay Mesa-Miguel Tap-Bay Boulevard 230 kV, at Miguel Substation to create two Otay Mesa-Miguel 230 kV lines. An alternative mitigation measure is to install a phase shifter on Imperial Valley-La Rosita 230 kV line to limit loop flow through the CFE system. The overload can also be mitigated by reconductoring the overloaded section of the line.

The study also identified N-1 violations on Division-Sampson 69 kV, Montgomery Tap-Sweetwater 69 kV and Sweetwater-Sweetwater Tap 69 kV lines following the outage of Silvergate-Boulevard 230 kV line. These overloads can be mitigated by reconfiguring TL23041, Otay Mesa-Miguel Tap-Sycamore 230 kV and TL23042, Otay Mesa-Miguel Tap-Bay Boulevard 230 kV, at the Miguel Substation to create two Otay Mesa-Miguel 230 kV lines. The overload on the Division-Sampson 69 kV line can also be mitigated by reconducting the line or by revising the existing Border SPS to trip Border and Otay generation following the outage. There is no plausible alternative for the other two overloaded lines since the ratings of the lines are already high. The recommended mitigation plan is to reconfigure TL23041 and TL23042 at the Miguel Substation to create two Otay Mesa-Miguel 230 kV lines. Because this project is a short lead time project and is currently in a pending LGIA, it is not necessary to further consider this project in this planning cycle.

The study also identified N-2 overloads on Poway-Rancho Carmel 69 kV and Bernardo-Rancho Carmel 69 kV lines following the outage of Artesian-Sycamore 69 kV and Bernardo-Sycamore 69 kV lines. SDG&E submitted a transmission project in the 2011 Request Window to reconductor Bernardo-Rancho Carmel 69 kV line, and the ISO found the project to be needed in the reliability assessment. The overload on Poway-Rancho Carmel can be mitigated either by using an existing SPS to trip Rancho Carmel load or by reconductoring the line.

A sensitivity assessment was also performed for minimum OTC generation. The sensitivity study assumed that Encina units 1-5 and GT are retired (964 MW total). Based on publicly available resource procurement information, 400 MW were added at Otay Mesa, and 100 MW were added at Mission-Miguel 230 kV line to replace the retired generation. Since the addition of this generation creates N-0 and N-1 violations in the Otay Mesa area, a reconfiguration project was also modeled to reconfigure TL23041, Otay Mesa-Miguel Tap-Sycamore 230 kV and TL23042, Otay Mesa-Miguel Tap-Bay Boulevard 230 kV, at Miguel Substation to create two Otay Mesa-Miguel 230 kV lines. The addition of generation at Otay Mesa also requires a modification of the existing Otay Mesa SPS to include generation tripping for N-1 outages of Otay Mesa-Miguel 230 kV lines.

The study results are listed in Table 4.10-14.

Table 4.10-14: Sensitivity deliverability assessment results for the SDG&E area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Miguel-Bay Boulevard 230 kV	Base Case	114 %	Imperial-SDG&E, Imperial-IID, San Diego South San Diego: existing-Otay Mesa, Imperial Valley DGs-Proctor Valley, Tele Canyon	1,126 MW	Reconductor line
Old Town-Penasquitos 230 kV	Base Case	101 %	Imperial-SDG&E, Imperial-IID, San Diego South Otay Mesa	30 MW	Reconductor line
Doublet Tap-Friars 138 kV	Old Town-Penasquitos 230 kV	122 %	Imperial-SDG&E, Imperial-IID, San Diego South San Diego: existing-Border, Otay, Otay Mesa; DGs-Imperial Beach, Otay, San Ysidro, Jamacha	638 MW	Reconductor line
Chicarita-Sycamore 138 kV	Encina 230/138 kV	117 %	DGs-Santee, Carlton Hills	0 MW	Reconductor line

Overloaded Facility	Contingency	Flow	Undeliverable Zone	MW Not Deliverable Without Upgrades	Mitigation
Pomerado-Poway 69 kV	Escondido-Pen 230 kV #1 and #2	102 %	DG-Pomerado	0 MW	Revise scope of previously approved transmission project to reconductor line (approved reconductor to 174 MVA, need at least 180 MVA)
Poway-Rancho Carmel 69 kV	Artesian-Sycamore 69 kV and Bernardo-Sycamore 69 kV	118 %	DG-Poway, Warren Canyon, Pomerado-Poway	0 MW	Reconductor line
Bernardo-Rancho Carmel	Artesian-Sycamore 69 kV and Bernardo-Sycamore 69 kV	103 %	DG-Poway, Warren Canyon, Pomerado-Poway	0 MW	Reconductor line
Silvergate-Old Town 230 kV	Mission-Old Town 230 kV and Silvergate-Old Town-Mission 230 kV	110 %	Imperial-SDG&E, Imperial-IID, San Diego South Otay Mesa	638 MW	Reconductor line

The sensitivity study identified an N-0 overload on Miguel-Bay Boulevard 230 kV line. The overload can be mitigated by reconductoring the line. The overload can also be mitigated by installing a phase shifter on the Imperial Valley-La Rosita 230 kV line to change the direction of the loop flow through the CFE system. Since the flow must be from west-to-east to eliminate the overload, this is not a feasible alternative.

The study also identified an N-0 overload on Old Town-Penasquitos 230 kV line. The overload can be mitigated by reconductoring the line. It can also be mitigated by a transmission project submitted by SDG&E through the 2010 Request Window, which was not found to be needed at that time and was not approved. The project would reconfigure TL23013, Old Town-Penasquitos 230 kV and TL23028, Silvergate-Old Town-Mission 230 kV.

This reconfiguration project also solves the N-1 overload on Doublet Tap-Friars 138 kV. Another way to mitigate this overload is to reconductor the line or to install an SPS to trip generation.

The study identified an overload on the Chicarita-Sycamore 138 kV line following the outage of Encina 230/138 kV transformer. This overload was not seen in the base portfolio deliverability assessment because it was mitigated by the dispatch of Encina generation. This overload can be mitigated by reconductoring the line.

The study also identified an overload on Pomerado-Poway 69 kV line following an N-2 outage. The mitigation is to revise the scope of a previously approved transmission project to reconductor the line. However, the previously approved reconductoring only brings the rating to 174 MVA, and mitigating the identified overload would require a rating of at least 180 MVA.

The study also identified overloads on Poway-Rancho Carmel 69 kV, and Bernardo-Rancho Carmel 69 kV lines following an N-2 outage. These overloads were also identified in the base portfolio deliverability study and the mitigations are the same as listed in that section.

The study also identified an overload on Silvergate-Old Town 230 kV line following an N-2 outage. The overload can be mitigated by reconductoring the line or installing an SPS to trip generation.

Because Encina can continue to operate as a once-through cooled power plant until 2017, there is no need to further consider any of the upgrades identified in this sensitivity study, in this planning cycle.

4.11 Conclusion of Policy-Driven Assessment to Meet 33% RPS

4.11.1 Summary of Policy-Driven Transmission Planning Assessment

Comprehensive assessments have been performed on all four RPS renewable portfolios, including power flow and stability assessment, deliverability assessment and production cost simulation.

According to ISO tariff section 24.4.6.6, Policy-Driven Elements, any transmission upgrade or addition elements that are required in the baseline scenario and at least a significant percentage of the stress scenarios may be category 1 elements. Transmission upgrades or additions that are required in the base case, but which are not required in any of the stress scenarios or are required in an insignificant percentage of the stress scenarios, generally will be category 2 elements, unless the ISO finds that sufficient analytic justification exists to designate them as category 1. The ISO identified numerous reliability concerns during the transmission analysis of the four portfolios. However, most of the identified mitigation are incremental upgrades with short lead times. In addition, much of the mitigation was only needed in the sensitivity portfolios. Accordingly, the results of the policy-driven assessment did not identify any new transmission additions or upgrades that qualify as category 1 or category 2 elements.

SECTION IV: ECONOMIC-NEED ASSESSMENT

Chapter 5

Economic Planning Study

The primary objective of the ISO economic planning study is to identify potential transmission congestion in the ISO-controlled grid and identify cost-effective solutions to mitigate the congestion. The study was accomplished by simulating future system conditions consistent with the Unified Planning Assumptions. The studies used the production simulation as a primary tool to identify grid congestion and evaluate the economic benefits of congestion mitigation measures. The production simulation is based on the algorithms of Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED). The quantification of potential benefits is measured in reduction of ISO ratepayer's cost based on the ISO's Transmission Economic Analysis Methodology (TEAM).

The economic planning study was performed after evaluations of policy-driven transmission (i.e., meeting RPS goals) and reliability-driven transmission assessment were completed. Network upgrades determined by reliability and renewable studies were modeled as inputs in the economic planning database. In that way, economically driven transmission needs are not redundant to the reliability- and policy-driven transmission needs.

5.1 Study Steps

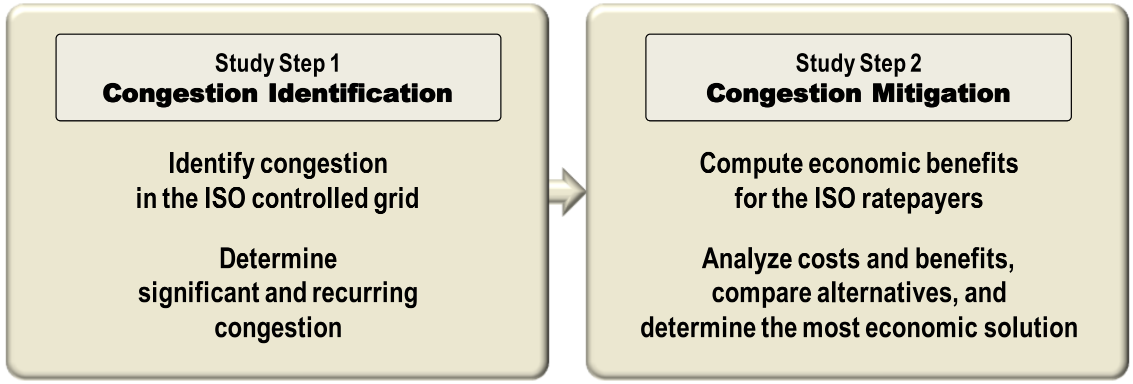
The economic planning study weighs the costs and benefits of a proposed project. In order for a proposed network upgrade to qualify as an economic project, it has to demonstrate a positive net benefit to ratepayers. This benefit may be reflected in a reduction of production cost, congestion cost, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources. In comparing different alternatives, the mitigation plan that has the largest net benefit is generally considered to be the most economic solution.

In the ISO economic planning study, the required criteria is that the ISO ratepayer benefit needs to be greater than the total cost in order to justify an economic project. Typically, the economic benefit includes three components: consumer payment decrease, generation revenue increase and transmission congestion revenue increase for the ratepayers. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and the TEAM principles.[27]

The economic planning study was conducted in two consecutive steps: congestion identification and congestion mitigation. The two study steps are shown in Figure 5.1-1.

[27] http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

Figure 5.1-1: Economic planning study – two steps



In the first study step, a production simulation was conducted for 8,760 hours for each study year. In the simulation results, grid congestion was tabulated and ranked by congestion costs (in millions of dollars) and congestion duration (in hours). The top five most severe congestion issues were identified as high-priority studies that were to be analyzed in the second study step. In addition, stakeholders submitted requests for economic planning studies that have also been studied by the ISO.

In the second study step (congestion mitigation), for each of the top five congestion issues, alternative mitigation plans were evaluated. Using production simulation and other means, the ISO determined the economic benefits for proposed mitigation plans. Finally, a cost-benefit analysis was performed to determine if the proposed mitigation plans are economic. Among all the mitigation plans that would address identified congestion issues, the plan that had the largest net benefit was determined to be the most economic solution.

5.2 Technical Approach

Economic benefits of transmission network upgrades can be evaluated by engineering analysis using production simulation and traditional power flow studies.

The production simulation is an important foundation for the economic planning study. Based on SCUC and SCED algorithms, the production simulation computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective of minimizing production costs, the computation balances supply and demand by dispatching economic generation while observing transmission constraints. The simulation also identifies transmission congestion over the entire study period. By comparing the “pre-project” and “post-project” study results, economic benefits can be calculated from savings of production costs or ratepayer payments.

In addition to the economic benefits computed by production simulation, any other benefits — where applicable and quantifiable — can also be included. For example, an upgrade of in-state transmission facilities may lead to reduction of local capacity requirement in an area. In this case, the transmission upgrade yields local capacity benefits. In another example, an upgrade of import transmission facilities may lead to a reduction of ISO system resource adequacy requirements if out-of-state resources are less expensive to procure than in-state resources. In this case, the transmission upgrade yields system capacity benefits.

5.3 Tools and Database

For this study, the ISO used ABB GridView™ software to conduct production simulation and GE PSLF™ to conduct power flow computations. The GridView™ program used was version 8.0 released on October 24, 2011. The PSLF™ program used was version 17.0_06 released on April 2, 2010.

For production simulation, the WECC production cost model was used in the study. The database model is often referred to as the Transmission Expansion Planning Policy Committee (TEPPC) dataset. In this study, the TEPPC dataset used was the “2020 PC0” case that was released by TEPPC on November 22, 2010. To perform the studies, the ISO applied updates and additions to the original TEPPC database, with attention to modeling the California power system and various resource portfolios in more details. Using the TEPPC database as a reference, the ISO developed the 2016 and 2021 base cases for this economic planning study.

5.4 Study Assumptions

This section summarizes major assumptions used in the economic planning study.

5.4.1 Generation Assumptions and Modeling

For renewable generation, the study modeled five alternative RPS net short portfolios as listed in Table 5.4-1. Those renewable portfolios were described in detail in Chapter 4.

Table 5.4-1: Assumptions of Renewable Portfolios

Acronym	Renewable Portfolios	Study Case
BS	Base portfolio (modified cost-constrained scenario)	Base case
CC	Cost-constrained portfolio	Sensitivity case 1
EC	Environmentally constrained portfolio	Sensitivity case 2
TC	Time-constrained portfolio	Sensitivity case 3
TR	Trajectory portfolio	Sensitivity case 4

For thermal generation, the study models new generation additions as described in Chapter 4. One particular modeling consideration is OTC power plants in the California coastal areas. The OTC assumption is based on the study conclusion of the AB1318 air quality studies described in Chapter 3, Section 3.4.

5.4.2 Load Assumptions and Modeling

In the production cost model, a 1-in-2 heat wave load was represented.

- To model the load in California areas, the study used the CEC demand forecast published in 2009.
- To model the load in Arizona areas (APS, SRP and TEP), the study used data provided by Arizona Public Service in December 2011.
- To model the load in out-of-state areas other than, the study used forecast data gathered by the WECC Load and Resources Subcommittee in 2011.

On top of the TEPPC database, the ISO enhanced the load distribution model. In the original TEPPC database, only one summer load distribution pattern was modeled. In order to reflect different seasonal pattern, the ISO added three additional load distribution patterns of spring, autumn and winter. Thus, in the final database, load distribution patterns were represented in four seasons.

5.4.3 Transmission Assumptions and Modeling

In the production simulation database, the entire WECC system was represented in a nodal network. Transmission limits were enforced on individual transmission lines, paths (i.e., flowgates) and nomograms.

In the original TEPPC database, the limits for more than half of the 500 kV and 345 kV transmission lines were not enforced. For this study, the ISO enforced the limits for all 500 kV and 345 kV transmission lines throughout the system. In the original TEPPC database, the limits for most of the 230 kV transmission lines in California were not enforced. For this study, the ISO enforced the limits for all 230 kV transmission lines in California. Such modifications to the TEPPC database were to make sure that transmission line flows stayed within their rated limits.

Another important enhancement by the ISO is the addition of contingency constraints in the transmission model. In the original TEPPC database, no contingencies were modeled. In the updated database, the ISO models contingency constraints on the 500 kV and 230 kV voltage levels in the California transmission grid. The contingency constraints were modeled to make sure that in the event of a loss of one (and sometimes multiple) transmission facility, the remaining transmission facilities would stay within their emergency limits.

The study modeled state-wide renewable transmission projects that received regulatory approvals or were identified in signed LGIAs. Those renewable transmission projects were described and listed in Chapter 4.

The study also modeled two reliability-driven projects identified in the current 2011/2012 planning cycle, because the proposed projects were determined to be needed to mitigate reliability concerns. The two reliability-driven projects are the

Tulucay 230/60 kV transformer #1 capacity increase in the PG&E area with a proposed operation year in 2014, and the Del Amo – Ellis 230 kV loop in the SCE area with a proposed operation year in 2013.

5.4.4 Accounting Parameters Used in Cost-Benefit Analysis

In the cost-benefit analysis, the total costs and benefits of a project or mitigation proposal were compared. In this chapter, the terms “total cost” and “total benefit” are defined as follows:

- Total cost is the total revenue requirement in the present value. In other words, the cost consists of all expenses including capital investments, taxes, maintenance costs and any other payments.
- Total benefit means the accumulated yearly benefits over the project’s economic life. The total benefit is also in the present value US dollars.

The total benefit is calculated as the sum of discounted yearly benefits over the economic life of the studied network upgrade. In this economic planning study, engineering analysis (e.g. production simulation and power flow analysis) determines the yearly benefits for 2016 and 2021 respectively. For the intermediate years between 2016 and 2021, the benefits were estimated by linear interpolation. For years beyond 2021, the benefits were estimated by an assumed escalation rate.

In calculation of the total benefit, the following accounting parameters were used:

- Economic life of new transmission facilities = 50 years
- Economic life of upgraded transmission facilities = 40 years
- Benefits escalation rate beyond year 2021 = 1 percent
- Benefits discount rate = 7 percent (real)
- Rate of system RA benefit = $5/kW-year (assumed price difference between CA and out-of-state)
- Rate of LCR benefit = $20/kW-year (assumed price difference between LCR and system RA)
- Conversion multiplier from capital cost to revenue requirement = 1.45

In this economic planning study, all the costs and benefits are expressed in US dollars in year 2010 values.

5.5 Study Results — Congestion Identification

Congestion identification is the first step in the economic planning study. In this study step, grid congestions were identified by the production simulation of 8,760 hours in each study year. The simulation was performed for study cases of 2016 (the 5th planning year) and 2021 (the 10th planning year).

Table 5.5-1 lists the results of identified potential congestion for the base case. In the table, severity of congestion is ranked by average congestion costs in the last column, and congestion issues are grouped into fourteen areas.

Table 5.5-1: Congestion in the ISO-controlled grid (base case)

#	Description	Utility	Year 2016		Year 2021		Average Congestion Cost ($M)
			Duration (hours)	Cost ($M)	Duration (hours)	Cost ($M)	
1	Path 26 (Northern-Southern California)	PG&E, SCE	183	1.880	141	1.636	1.758
2	Greater Fresno Area (GFA)	PG&E	384	1.092	354	1.713	1.402
3	Greater Bay Area (GBA)	PG&E	151	0.234	276	0.626	0.403
4	Los Banos North (LBN)	PG&E, TID	3	0.017	27	0.529	0.273
5	Path 24 (PG&E-Sierra)	PG&E, SPP	90	0.138	140	0.331	0.234
6	Path 61 (Victorville-Lugo)	SCE, LADWP	25	0.324	12	0.077	0.200
7	Lugo area	SCE	60	0.298	-	-	0.149
8	Path 60 (Inyo-Control 115 kV tie)	SCE, LADWP	205	0.110	192	0.113	0.112
9	Path 41 (Sylmar to SCE)	SCE, LADWP	4	0.078	4	0.058	0.068
10	Central Valley Area (CVA)	PG&E	4	0.009	4	0.045	0.027
11	Path 45 (SDG&E – CFE)	SDG&E	-	-	9	0.053	0.027
12	LA metro area	SCE	4	0.055	-	-	0.027
13	AZ-CA	SCE	1	0.009	-	-	0.004
14	San Diego Area (SDA)	SDG&E	-	-	1	0.006	0.003

For full details of the identified congestion, see Appendix D. In addition to the base case congestion, the Appendix D also provides results of identified congestion for four other RPS portfolios.

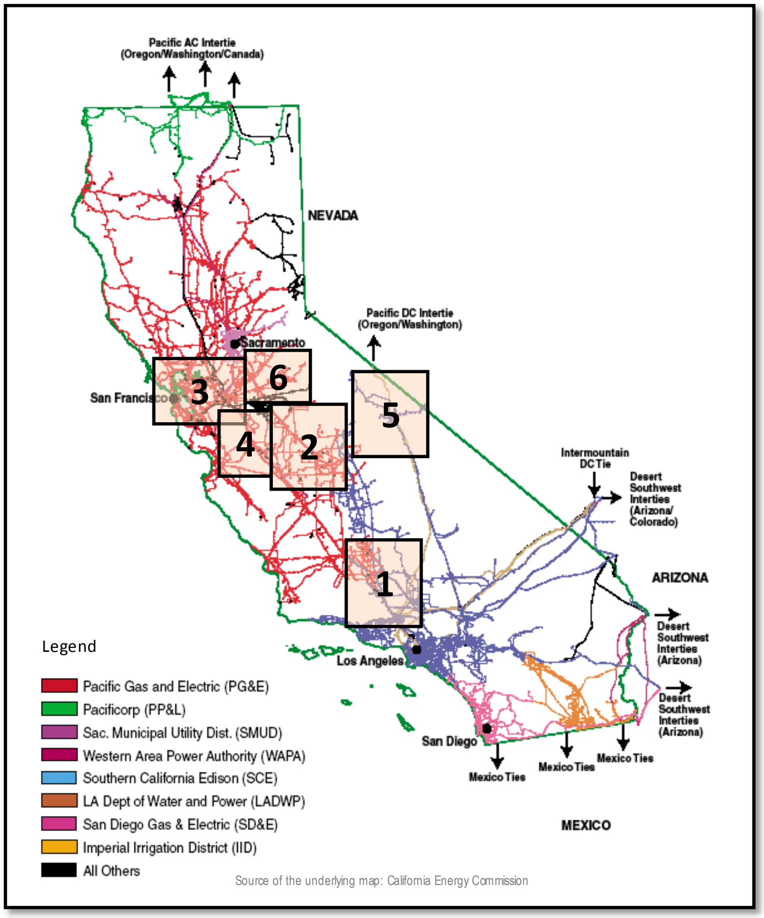
Generally, the ISO selects the top-five congestion issues to be analyzed in economic assessment. In this economic planning study, the ISO selected congestion issues #1, #2, #3, #4, #8 and #10 listed in Table 5.5-1 as high-priority studies, where economic benefits of congestion mitigation measures were assessed.

5.6 Study Results — Congestion Mitigation

Congestion mitigation is the second step in the economic planning study. This step took the high-ranking congestion issues and calculated the economic benefits of their mitigation congestion mitigation measures.

Figure 5.6-1 shows the geographic locations of the six selected congestion issues that were assessed for economic benefits in congestion mitigation.

Figure 5.6-1: Overview of six congestion issues analyzed in high-priority studies



Congestion mitigation analysis		
Study ID	**Study subject**	**Alternatives studied**
CM1of6	Path 26 (Northern - Southern CA)	Four
CM2of6	Greater Fresno Area (GFA)	One
CM3of6	Greater Bay Area (GBA)	Four
CM4of6	Los Banos North (LBN)	One
CM5of6	Path 60 (Inyo - Control 115 kV Tie)	Three
CM6of6	Central Valley Area (CVA)	Two

Table 5.6-1 lists the selected congestion issues. For those issues, the ISO conducted high-priority studies with detailed analysis of the congestion mitigation measures.

Table 5.6-1: Top-five congestion issues in the ISO-controlled grid

ID	Description	Utility	Congestion Duration (Hours)	
			Year 2016	Year 2021
CM1of6	Path 26 (Northern-Southern California)	PG&E, SCE	183	141
CM2of6	Greater Fresno Area (GFA)	PG&E	384	354
CM3of6	Greater Bay Area (GBA)	PG&E	187	460
CM4of6	Los Banos North (LBN)	PG&E	3	27
CM5of6	Path 60 (Inyo-Control 115 kV tie)	SCE, LADWP	205	192
CM6of6	Central Valley Area (CVA)	PG&E	4	4

The following sub-sections provide evaluations of the congestion mitigation measures for each of the six congestion issues.

5.6.1 Path 26 (Northern-Southern California)

Table 5.6-2 lists the identified congestion on Path 26 in the north to south direction (i.e., from Midway to Vincent).

Table 5.6-2: Congested facilities on Path 26 (Northern-Southern California)

#	Transmission Facilities	Year 2016		Year 2021	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Midway-Vincent 500 kV line #1, subject to loss of #2 line	13	0.073	11	0.079
2	Midway-Vincent 500 kV line #2, subject to loss of #1 line	15	0.273	48	0.516
3	Midway-Vincent 500 kV line #1, subject to loss of Midway-Whirlwind line	31	0.327	11	0.058
4	Midway-Vincent 500 kV line #2, subject to loss of Midway-Whirlwind line	71	1.084	69	0.969
5	Path 26 (Midway-Vincent) path rating	30	0.123	4	0.015
	Total:	183	1.880	141	1.636

As seen from the simulation results above, Path 26 congestion occurs mainly on the Midway-Vincent 500 kV lines #1 or #2, subject to loss of the parallel transmission line. The congestion direction is from north to south. In addition to the L-1 congestion, the simulation results also showed some limit bindings on the north-to-south path rating.

Figure 5.6-2 shows a system diagram of the Path 26 and simulated congestion hours under cases of different RPS portfolios.

Figure 5.6-2: Path 26 system diagram and simulated congestion hours

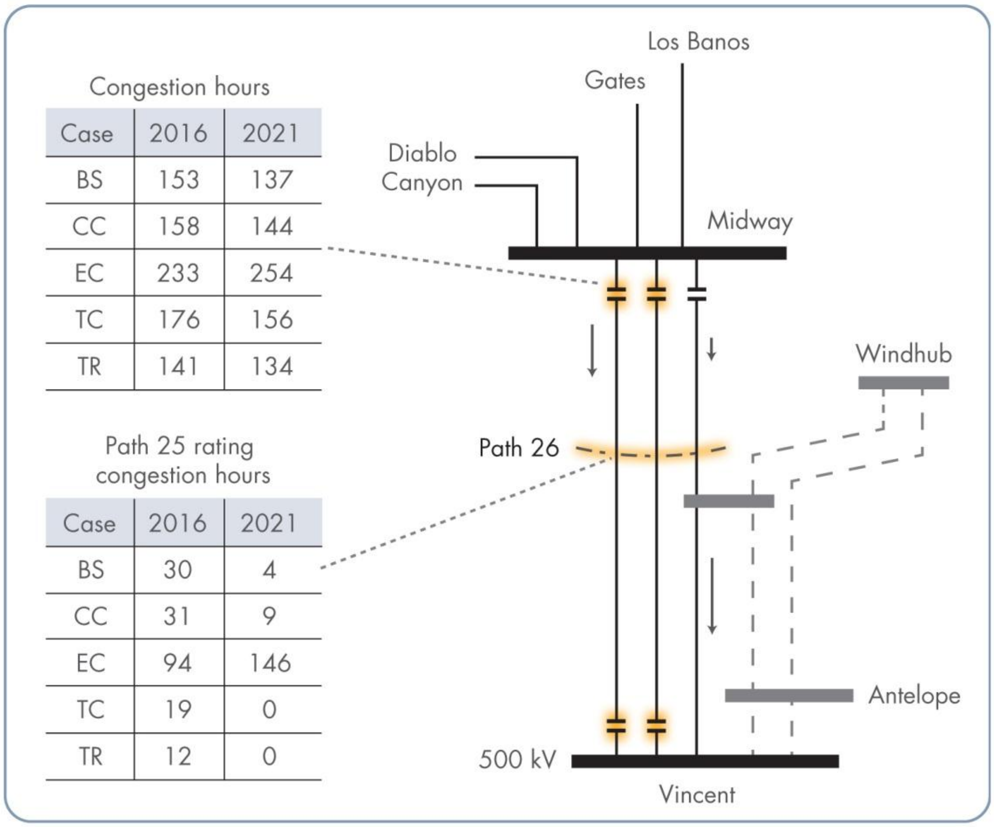
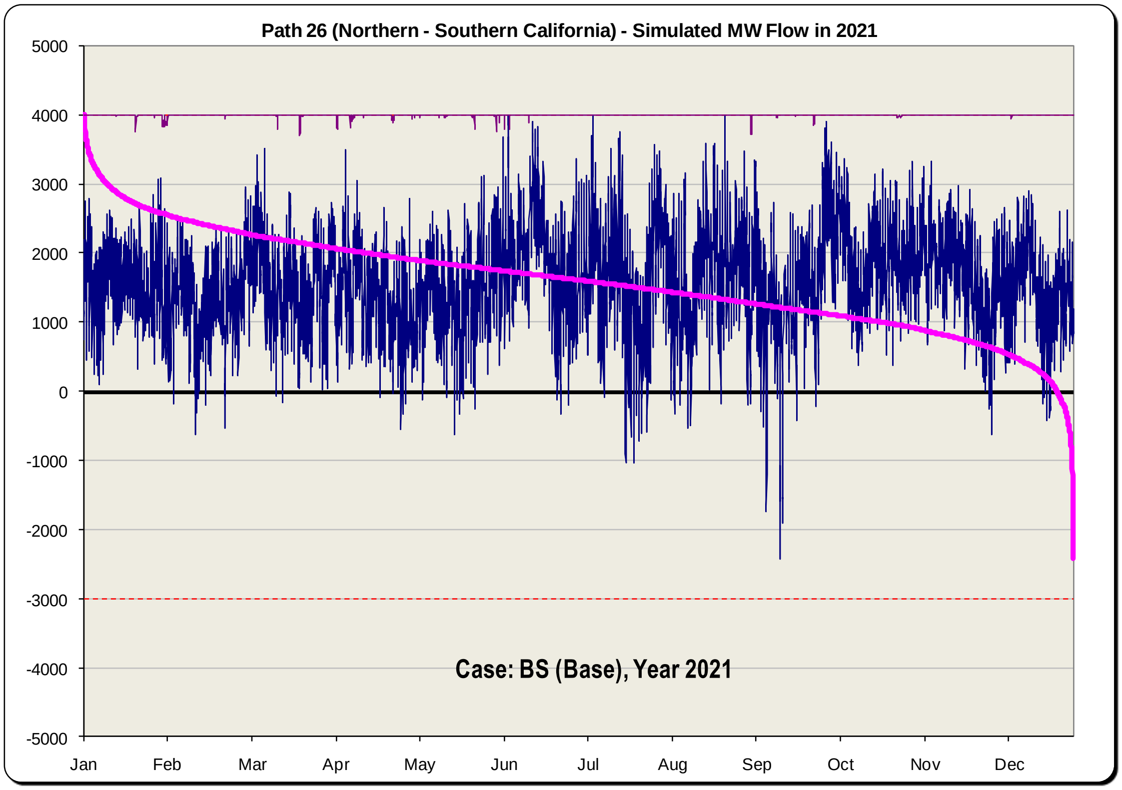
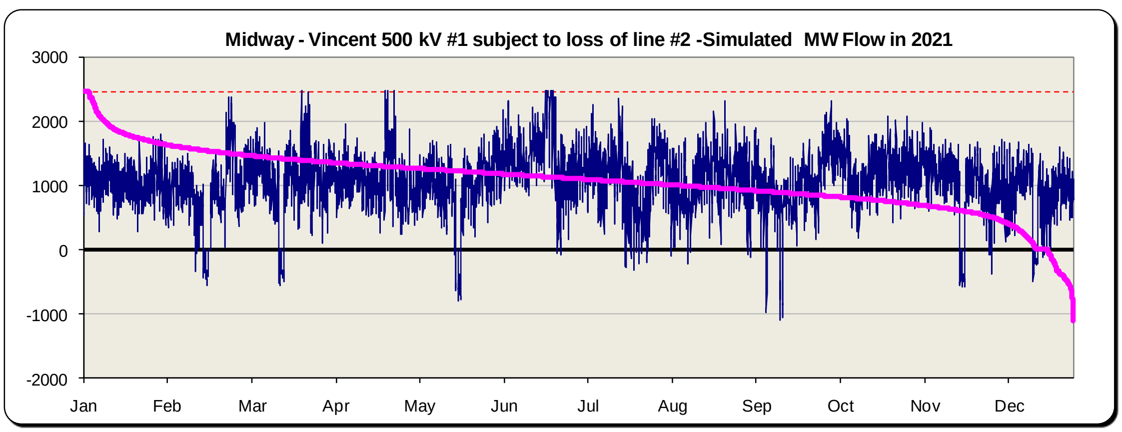


Figure 5.6-3 shows simulated power flow on the Path 26.

Figure 5.6-3: Simulated Power Flow on Path 26





To alleviate the Path 26 congestion, this study evaluated four alternative mitigation plans and made economic assessment for each of the alternatives. Figure 5.6-4 through Figure 5.6-7 show the congestion mitigation effects and economic assessment.

Figure 5.6-4: Alternative 1: Upgrade series capacitors on Midway – Vincent 500 kV lines #1 and #2

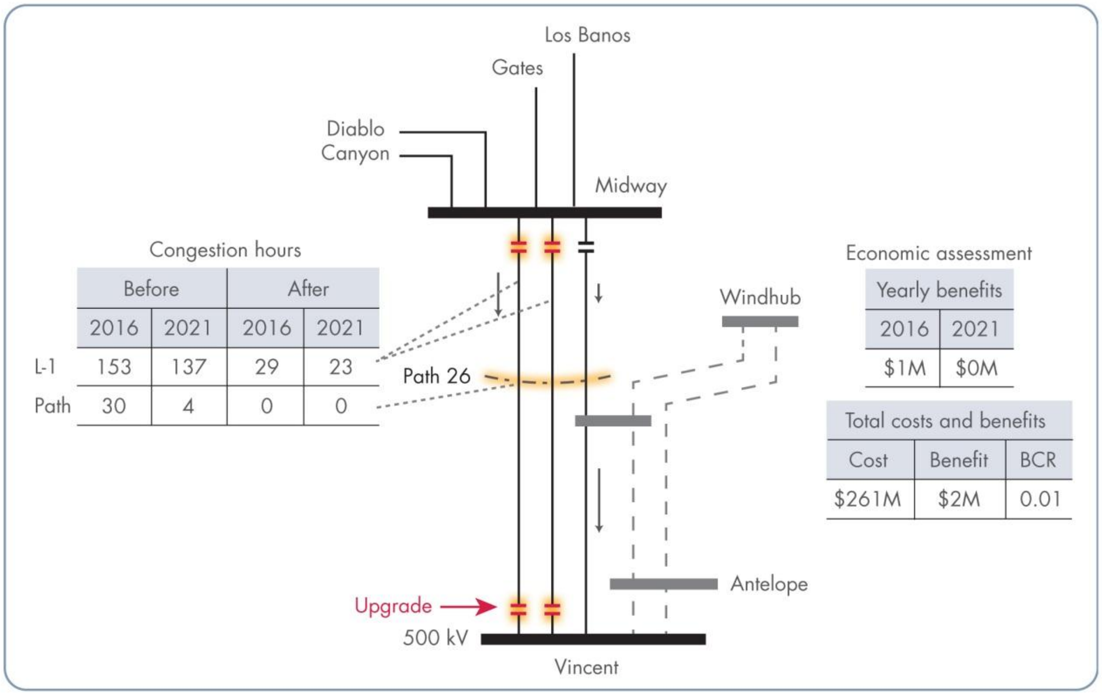


Figure 5.6-5: Alternative 2: Build Midway – Whirlwind 500 kV line #2

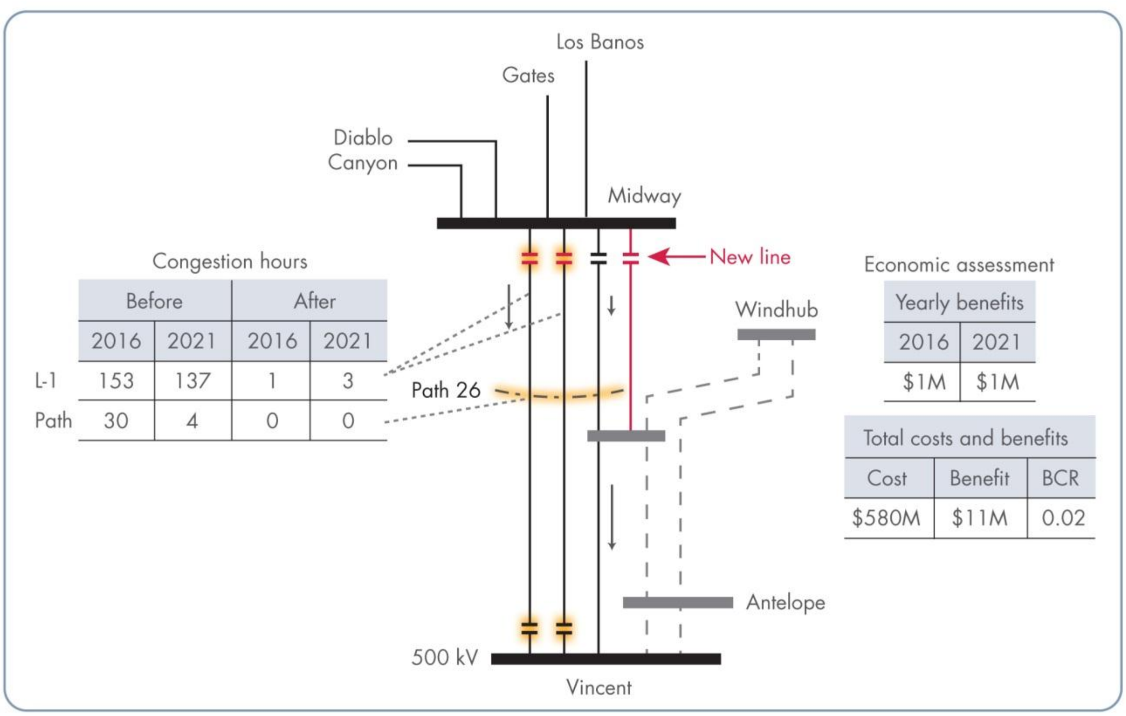


Figure 5.6-6: Alternative 3: Build Midway – Antelope 500 kV line

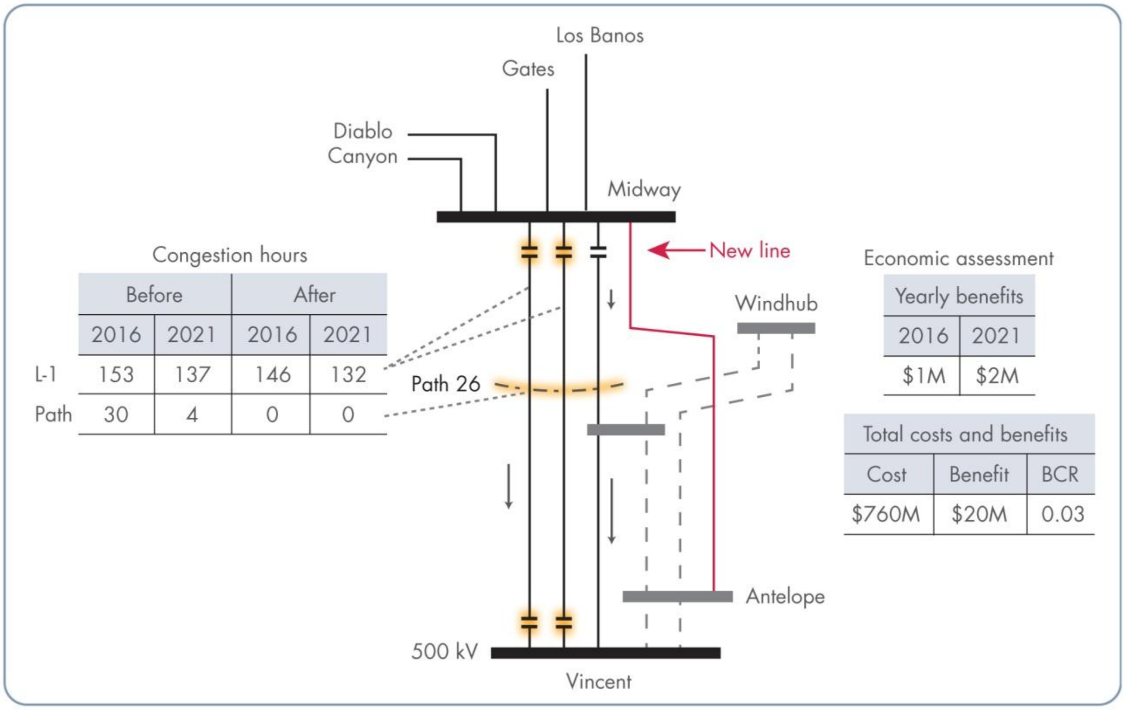
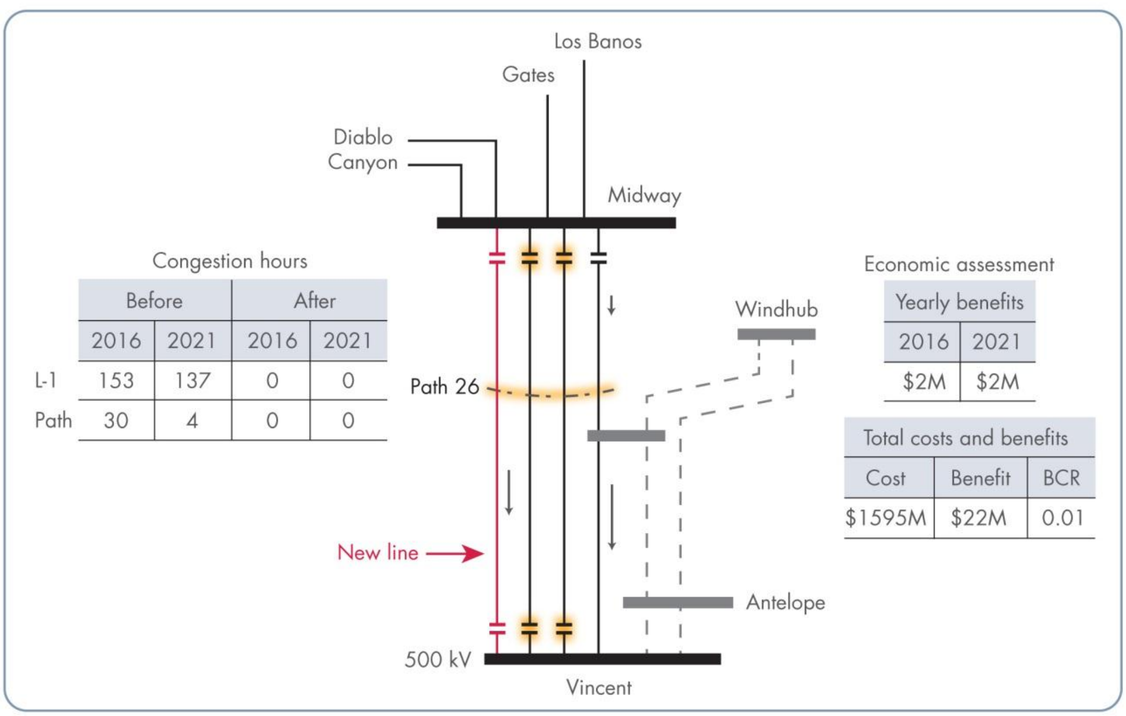


Figure 5.6-7: Alternative 4: Build Midway – Vincent 500 kV line #4



In the following, an economic assessment is made. Table 5.6-3 shows cost estimates for the proposed network upgrade. Table 5.6-4 lists quantified economic benefits. Table 5.6-5 provides a cost-benefit analysis.

Table 5.6-3: Cost estimates for congestion mitigation measures for Path 26

Alt.	Description	Capital Cost	Total Cost
1	Upgrade series capacitors on the Midway-Vincent 500 kV line #1 and #2	$180M	$261M
2	Build new Midway-Whirlwind 500 kV #2 (~80 miles)	$400M	$580M
3	Build new Midway-Antelope 500 kV line (~88 miles)	$524M	$760M
4	Build new Midway-Vincent 500 kV line #4 (~110 miles)	$1,100M	$1,595M

Table 5.6-4: Benefit quantification for congestion mitigation measures for Path 26

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Upgrade series capacitors of the Midway-Vincent 500 kV lines #1 and #2	2016	$1M	-	-	$1M	$2M
		2021	$0M	-	-	$0M	
2	Build new Midway-Whirlwind 500 kV #2	2016	$0M	-	$1M	$1M	$11M
		2021	$0M	-	$1M	$1M	
3	Build new Midway-Antelope 500 kV line	2016	$0M	-	$1M	$1M	$20M
		2021	$1M	-	$1M	$2M	
4	Build new Midway-Vincent 500 kV line #4	2016	$0M	-	$2M	$2M	$22M
		2021	$0M	-	2M	$2M	

Note: The losses benefits were roughly assumed values in absence of power flow computation

Table 5.6-5: Cost-benefit analysis of congestion mitigation measures for Path 26

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Upgrade series capacitors of the Midway-Vincent 500 kV line #1 and #2	$261M	$2M	($259M)	0.01
2	Build new Midway-Whirlwind 500 kV #2	$580M	$11M	($569M)	0.02
3	Build new Midway-Antelope 500 kV line	$760M	$20M	($740M)	0.03
4	Build new Midway-Vincent 500 kV line #4	$1,595M	$22M	($1,573M)	0.01

Based on the above analysis and results, the ISO has not identified any of the alternatives as needed.

5.6.2 Greater Fresno Area (GFA)

Table 5-6-6 lists the identified congestion in the Greater Fresno Area (GFA).

Table 5.6-6: Congestion identification in Central Valley Area — congestion hours and costs

#	Transmission Facilities	2016		2021	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Warnerville-Wilson 230 kV line	248	0.695	221	0.786
2	Warnerville-Wilson 230 kV line, subject to loss of Melones-Wilson 230 kV line	39	0.099	46	0.166
3	Warnerville-Wilson 230 kV line, subject to loss of Gates-Henrietta Tap 230 kV line	47	0.243	74	0.444
4	Borden-Gregg 230 kV line	50	0.056	22	0.313
5	Gates-Henrietta Tap 230 kV line, subject to loss of Panoche-McMullin 230 kV line	-	-	1	0.004
Total:		384	1.092	354	1.713

Figure 5.6-8 shows a system diagram of the Greater Fresno Area (GFA) 230 kV system and simulated congestion under cases of different RPS portfolios.

Figure 5.6-8: Greater Fresno Area (GFA) 230 kV system and simulated congestion

Caused by Helms pumping

Congestion hours

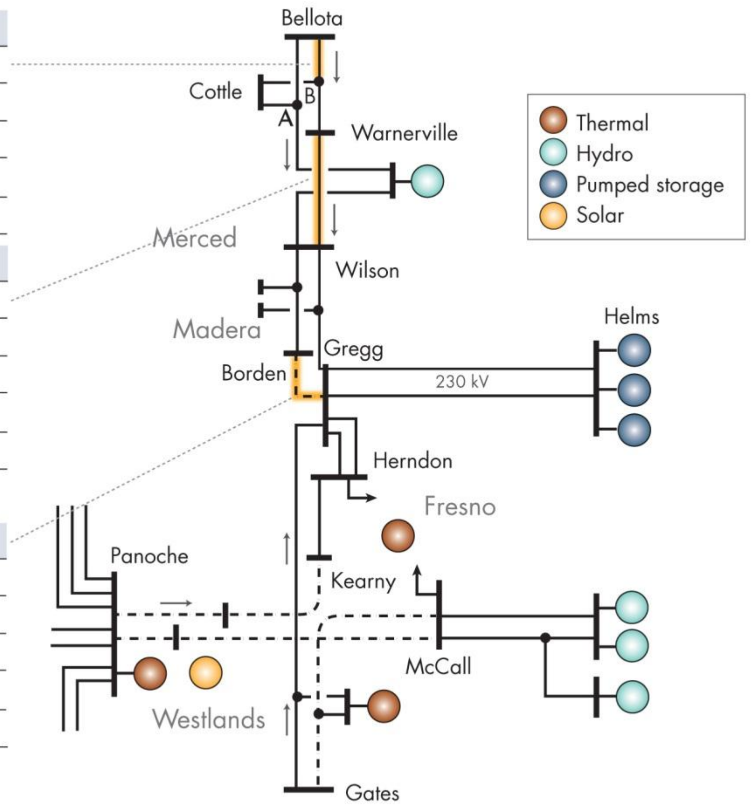
Case	2016	2021
BS	0	0
CC	0	1
EC	0	4
TC	0	4
TR	1	0

Case	2016	2021
BS	334	331
CC	321	239
EC	264	245
TC	341	359
TR	344	395

Caused by Helms generation

Congestion hours

Case	2016	2021
BS	50	22
CC	52	25
EC	27	4
TC	33	15
TR	43	23

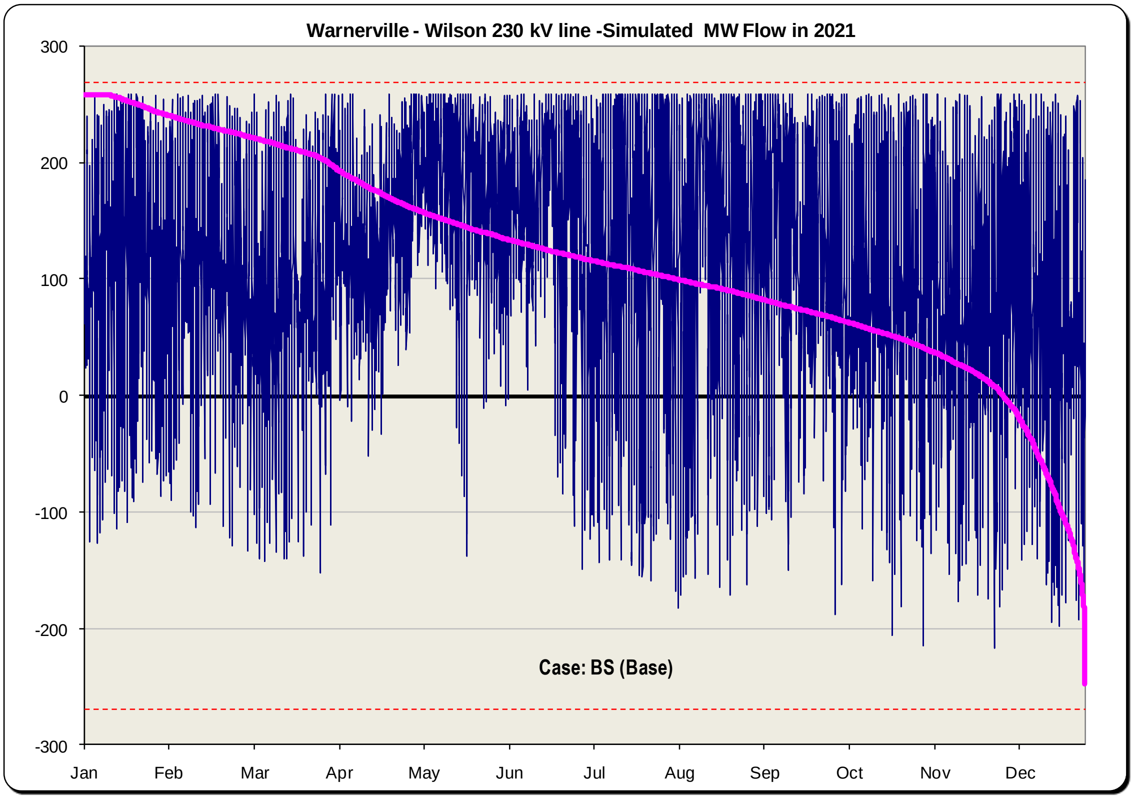


Borden - Gregg 230 kV Reconductoring Project
LGIA signed

Fresno Reliability Transmission Projects
Network upgrades of the existing 230 kV system approved in the ISO 2009/2010 Transmission Plan under construction

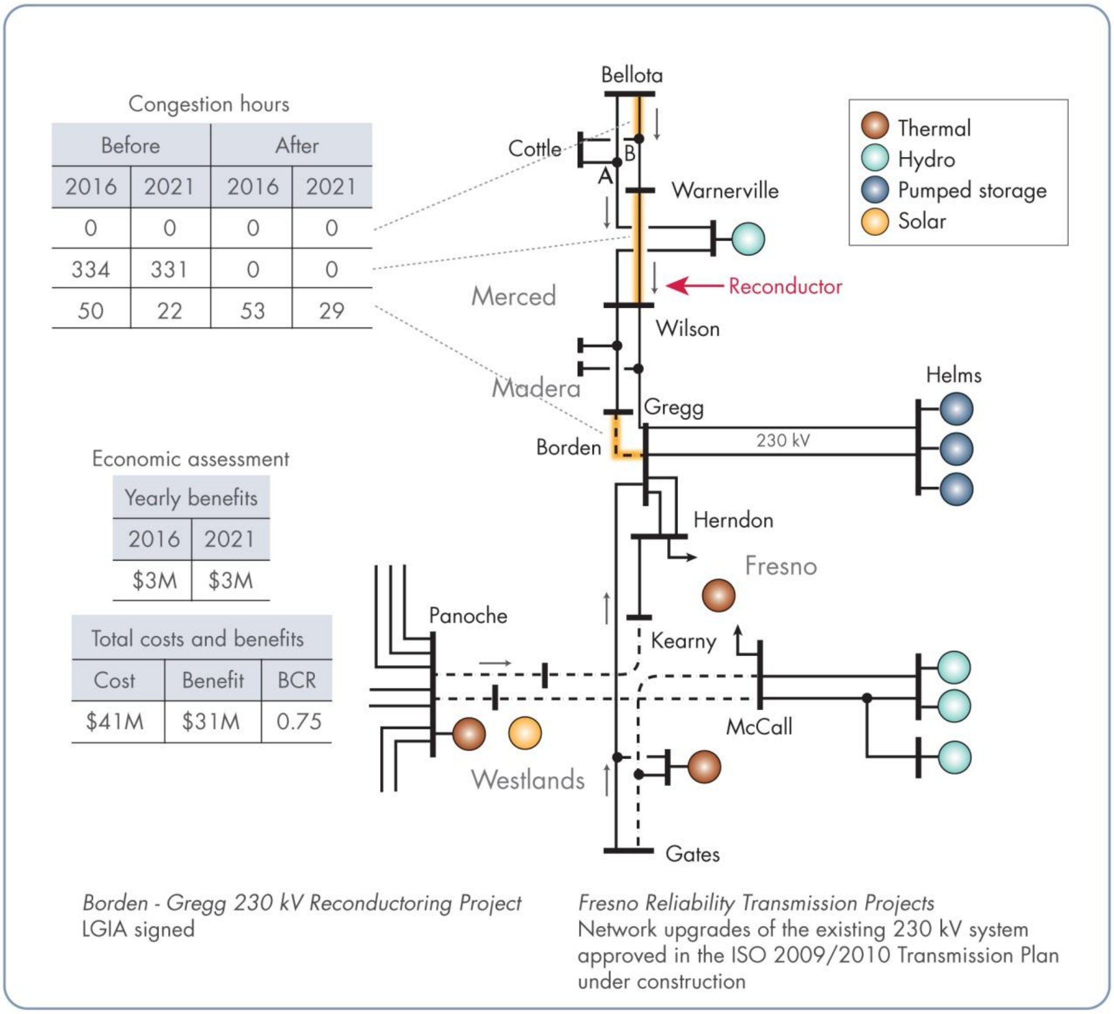
Figure 5.6-9 shows the simulated congestion on the Warnerville – Wilson 230 kV line in year 2021 with the base case.

Figure 5.6-9: Simulated power flow on the Warnerville-Wilson 230 kV line



To alleviate the congestion in Greater Fresno Area (GFA), this study evaluated one mitigation plan to reconductor the most congested Warnerville-Wilson 230 kV line. Figure 5.6-10 shows the congestion mitigation effects and economic assessment.

Figure 5.6-10: Alternative 1: Reconductor Warnerville-Wilson 230 kV line



In the following, an economic assessment is made. Table 5.6-7 shows cost estimates for the proposed network upgrade. Table 5.6-8 lists quantified economic benefits. Table 5.6-9 provides a cost-benefit analysis.

Table 5.6-7: Cost estimates for congestion mitigation measure for GFA

Alt.	Description	Capital Cost	Total Cost
1	Reconductor Warnerville – Wilson 230 kV line (~40 miles)	$28M	$41M

Table 5.6-8: Benefit quantification for congestion mitigation measures for GFA

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Reconductor Warnerville – Wilson 230 kV line	2016	$3M	-	-	$3M	$31M
		2021	$3M	-	-	$3M	

Table 5.6-9: Cost-benefit analysis of congestion mitigation measures for GFA

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Reconductor Warnerville – Wilson 230 kV line	$41M	$31M	($10M)	0.75

As seen from the above table, the economic benefit falls short in comparison with the cost of proposed reconductoring. Therefore, there is no economic justification for the proposed network upgrades.

5.6.3 Greater Bay Area (GBA)

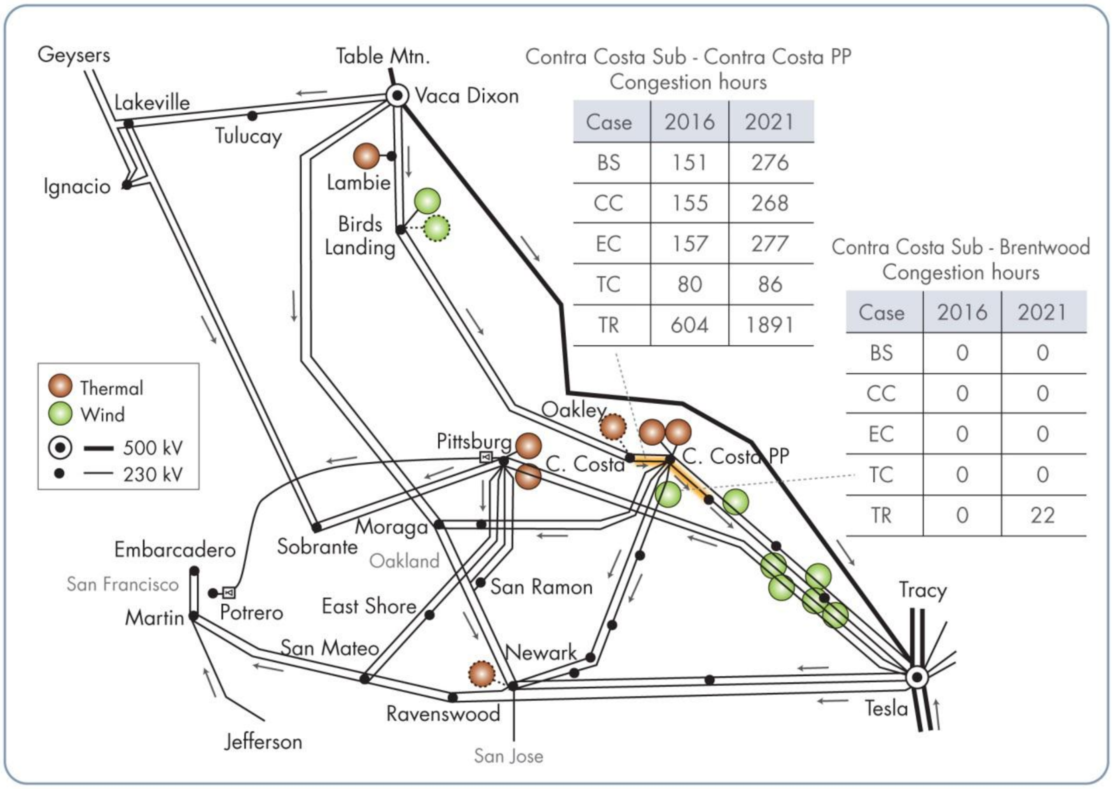
Table 5.6-10 lists the identified congestion in the Greater Bay Area.

Table 5.6-10 Congested facilities in the Greater Bay Area

#	Transmission Facilities	Year 2016		Year 2021	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
1	Contra Costa Sub-Contra Costa PP 230 kV line	187	0.309	455	0.886

Figure 5.6-11 illustrates network configuration in the Greater Bay Area and identified congestion under cases of different RPS portfolios.

Figure 5.6-11: Greater Bay Area (GBA) system diagram and simulated congestion



Contra Costa Sub - Contra Costa PP Congestion hours

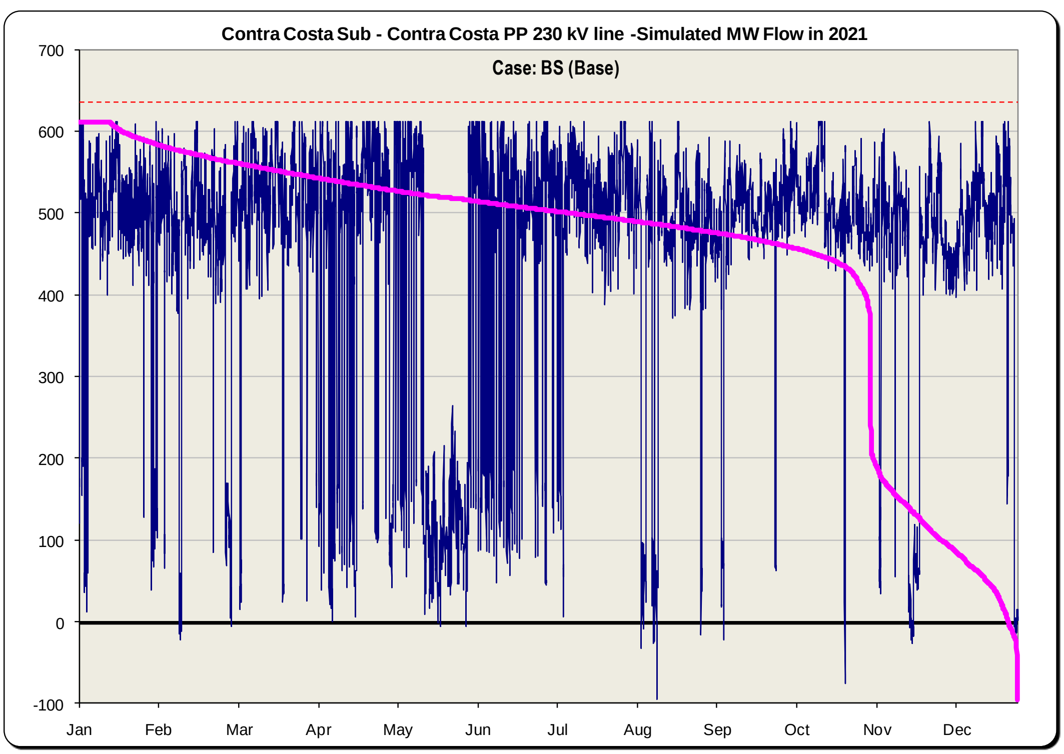
Case	2016	2021
BS	151	276
CC	155	268
EC	157	277
TC	80	86
TR	604	1891

Contra Costa Sub - Brentwood Congestion hours

Case	2016	2021
BS	0	0
CC	0	0
EC	0	0
TC	0	0
TR	0	22

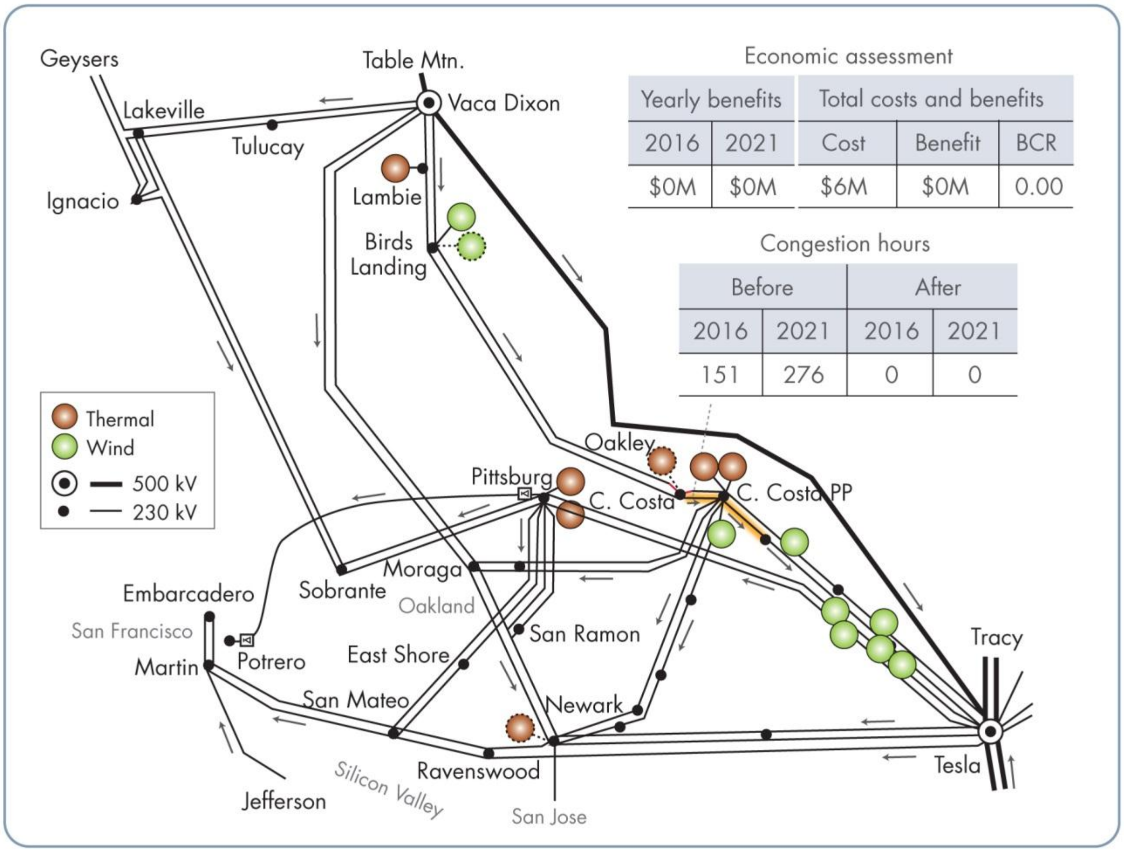
Figure 5.6-12 shows the simulated power flow on the Contra Costa Sub- Contra Costa PP 230 kV line in year 2021 with the base case.

Figure 5.6-12: Simulated power flow on the Contra Costa Sub-Contra Costa PP 230 kV line



To alleviate the GBA congestion, this study evaluated four alternative mitigation plans and made economic assessment for each of the alternatives. Figure 5.6-13 through Figure 5.6-16 show the congestion mitigation effects and economic assessment.

Figure 5.6-13: Alternative 1: Loop Birds Landing-Contra Costa PP 230 kV line into Contra Costa Sub



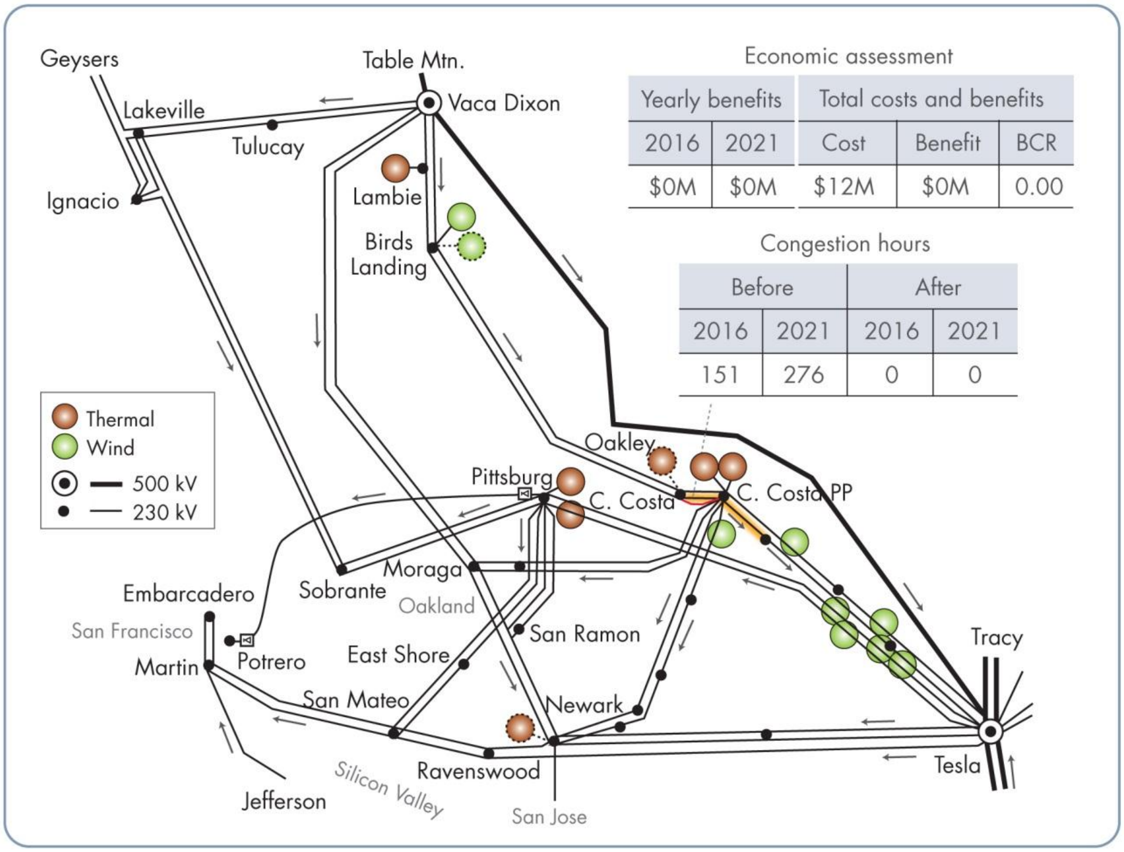
Economic assessment

Yearly benefits		Total costs and benefits		
2016	2021	Cost	Benefit	BCR
$0M	$0M	$6M	$0M	0.00

Congestion hours

Before		After	
2016	2021	2016	2021
151	276	0	0

Figure 5.6-14: Alternative 2: Build Contra Costa Sub-Contra Costa PP 230 kV line #2



Economic assessment

Yearly benefits		Total costs and benefits		
2016	2021	Cost	Benefit	BCR
$0M	$0M	$12M	$0M	0.00

Congestion hours

Before		After	
2016	2021	2016	2021
151	276	0	0

Figure 5.6-15: Alternative 3: Divert Birds Landing-Contra Costa 230 kV lines to Pittsburg

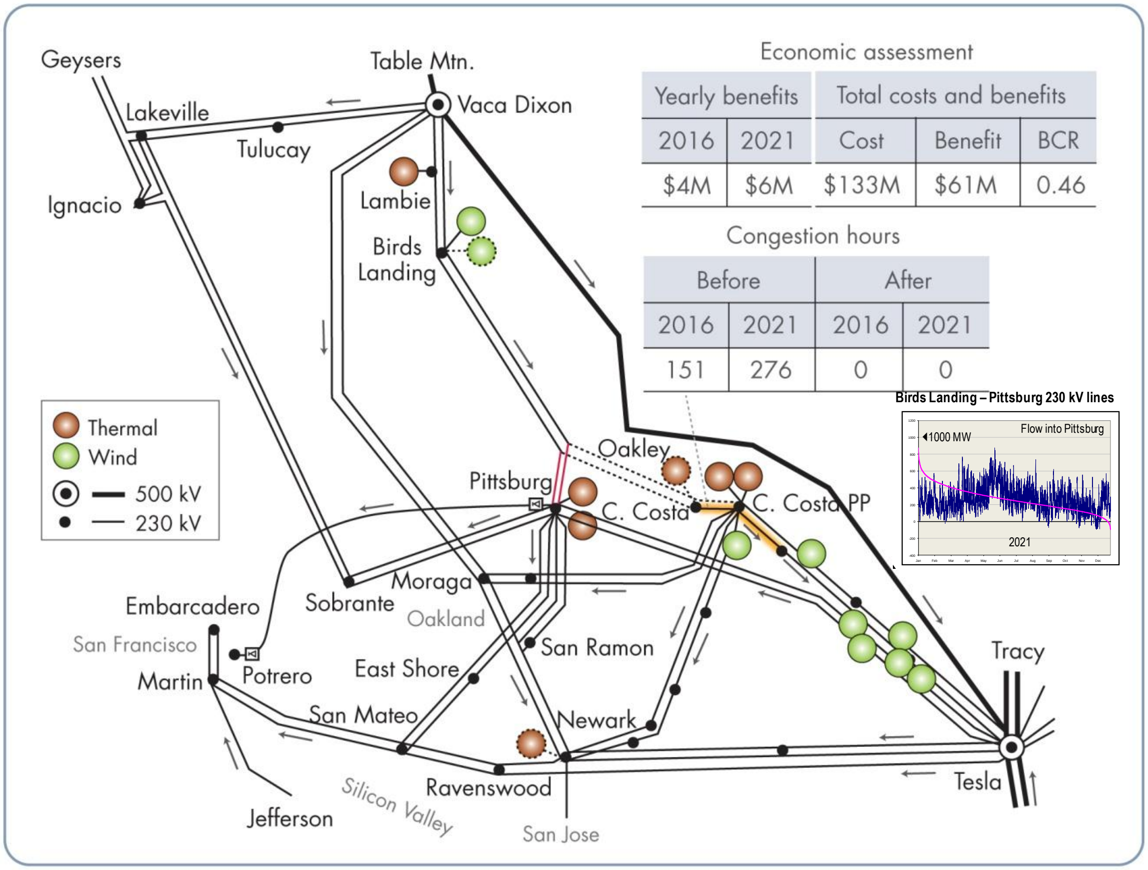
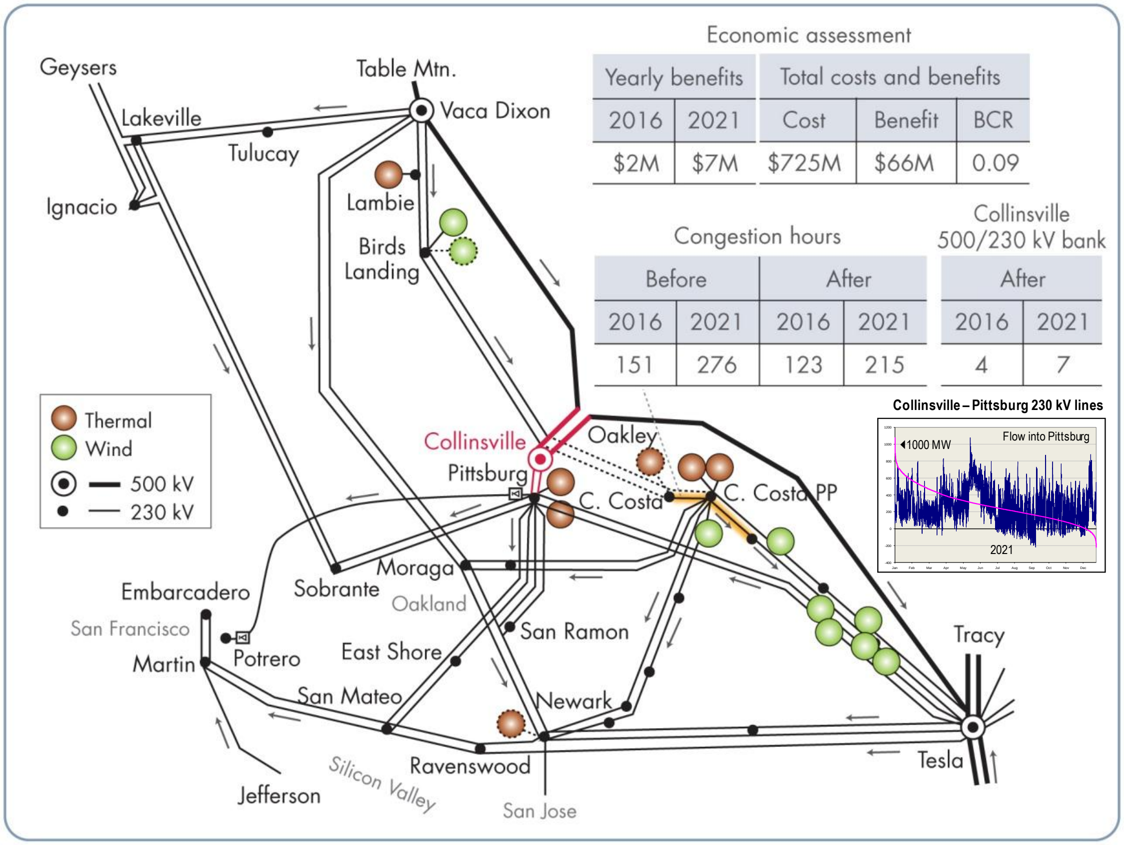


Figure 5.6-16: Alternative 4: Build Collinsville 500 kV Station, loop in Vaca Dixon-Tesla 500 kV line and build Collinsville-Pittsburg 230 kV double-circuit lines



In the following, an economic assessment is made. Table 5.6-11 shows cost estimates for the proposed network upgrade. Table 5.6-12 shows quantified economic benefits. Table 5.6-13 provides a cost-benefit analysis.

Table 5.6-11: Cost estimates for proposed congestion mitigation in the Greater Bay Area

#	Description	Capital Cost	Total Cost
1	Loop Birds Landing-Contra Costa PP 230 kV line into Contra Costa Sub	$4M	$6M
2	Build Contra Costa Sub-Contra Costa PP 230 line #2 (~2 miles)	$8M	$12M
3	Divert Birds Landing-Contra Costa 230 kV lines to Pittsburg (~8 miles new lines)	$93M	$133M
4	Build Collinsville 500 kV substation and loop in Vaca Dixon-Tesla 500 kV line (~2 mile new 500 kV line for loop-in, ~5 mile new 230 kV lines)	$500M	$725M

Table 5.6-12: Benefit quantification for congestion mitigation measures for Path 26

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Loop Birds Landing-Contra Costa PP 230 kV line into Contra Costa Sub	2016	$0M	-	-	$0M	$0M
		2021	$0M	-	-	$0M	
2	Build Contra Costa Sub-Contra Costa PP 230 line #2	2016	$0M	-	-	$0M	$0M
		2021	$0M	-	-	$0M	
3	Divert Birds Landing-Contra Costa 230 kV lines to Pittsburg	2016	$2M	$0M	$2M	$4M	$61M
		2021	$4M	$0M	$2M	$6M	
4	Build Collinsville 500 kV substation and loop in Vaca Dixon-Tesla 500 kV line	2016	$1M	$0M	$1M	$2M	$66M
		2021	$6M	$0M	$1M	$7M	

Table 5.6-13: Cost-benefit analysis of congestion mitigation measures for Path 26

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Loop Birds Landing-Contra Costa PP 230 kV line into Contra Costa Sub	$6M	$0M	($6M)	0.00
2	Build Contra Costa Sub-Contra Costa PP 230 line #2	$12M	$0M	($12M)	0.00
3	Divert Birds Landing-Contra Costa 230 kV lines to Pittsburg	$133M	$61M	($72M)	0.46
4	Build Collinsville 500 kV substation and loop in Vaca Dixon-Tesla 500 kV line	$725M	$66M	($659M)	0.09

Based on the above analysis and results, the ISO has not identified any of the alternatives as needed in the Greater Bay Area (GBA).

5.6.4 Los Banos North (LBN)

Table 5.6-14 lists the identified congestion in the Los Banos North (LBN).

Table 5.6-14: Congested facilities in Los Banos North (LBN)

#	Transmission Facilities	Year 2016		Year 2021	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
1	Los Banos-Westley 230 kV line	-	-	9	0.275
2	Los Banos-Westley 230 kV line, subject to loss of Los Banos-Tesla 500 kV line	3	0.017	18	0.254
	Total:	3	0.017	27	0.529

Figure 5.6-17 shows a system diagram and simulated congestion hours under cases of different RPS portfolios.

Figure 5.6-17: Los Banos North (LBN) system diagram and simulated congestion

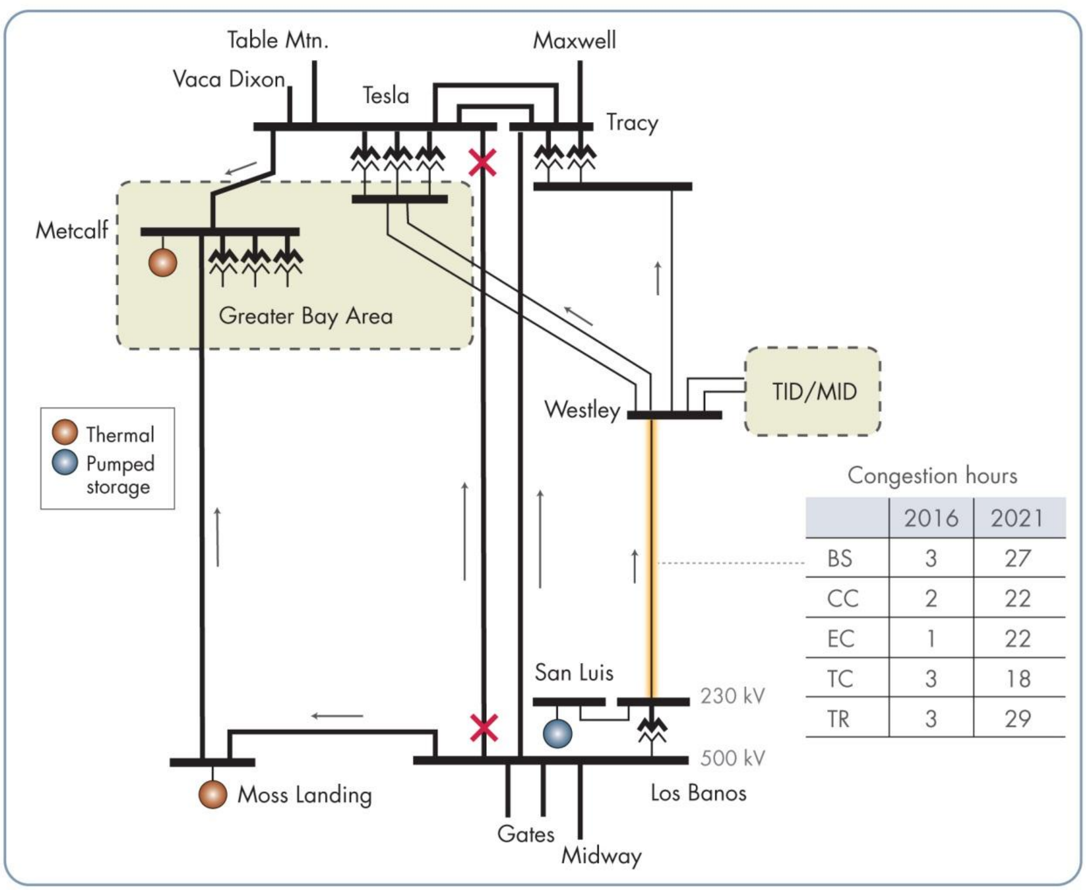
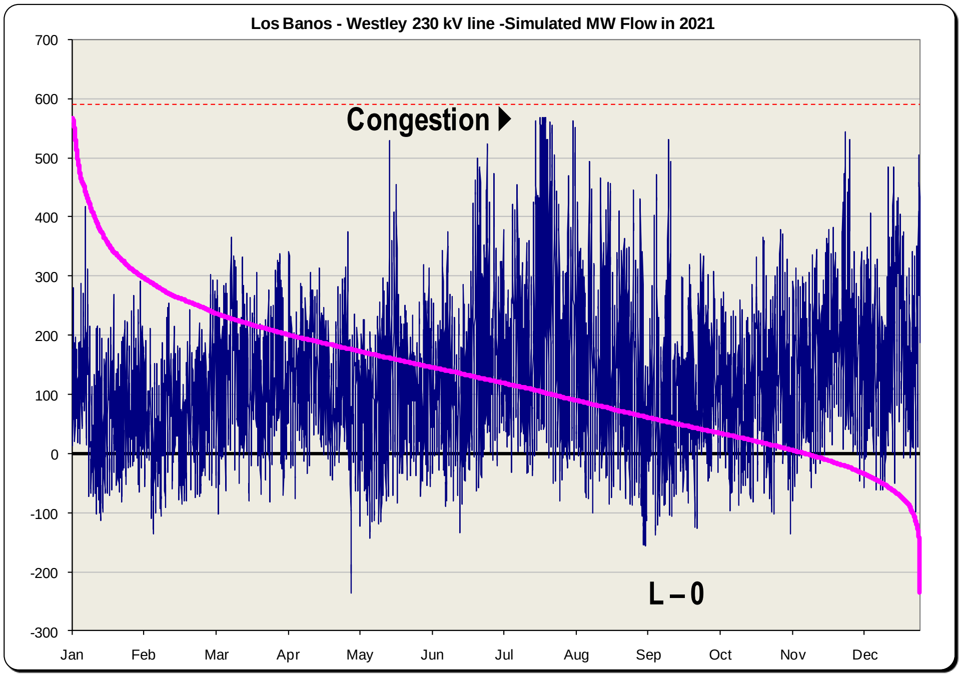
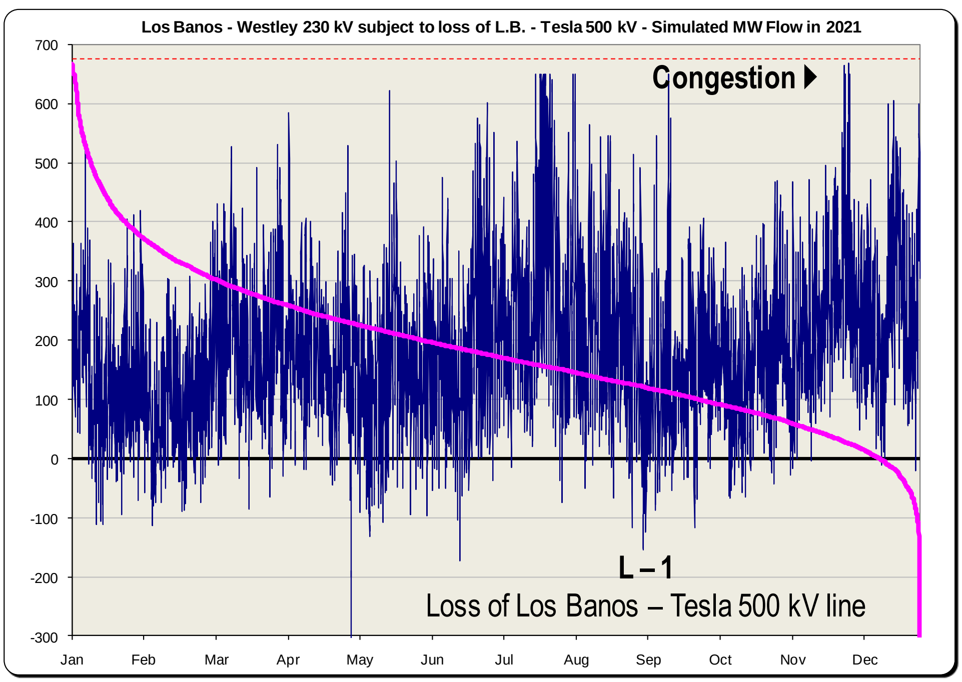


Figure 5.6-18 shows simulated power flow on the Los Banos-Westley 230 kV line.

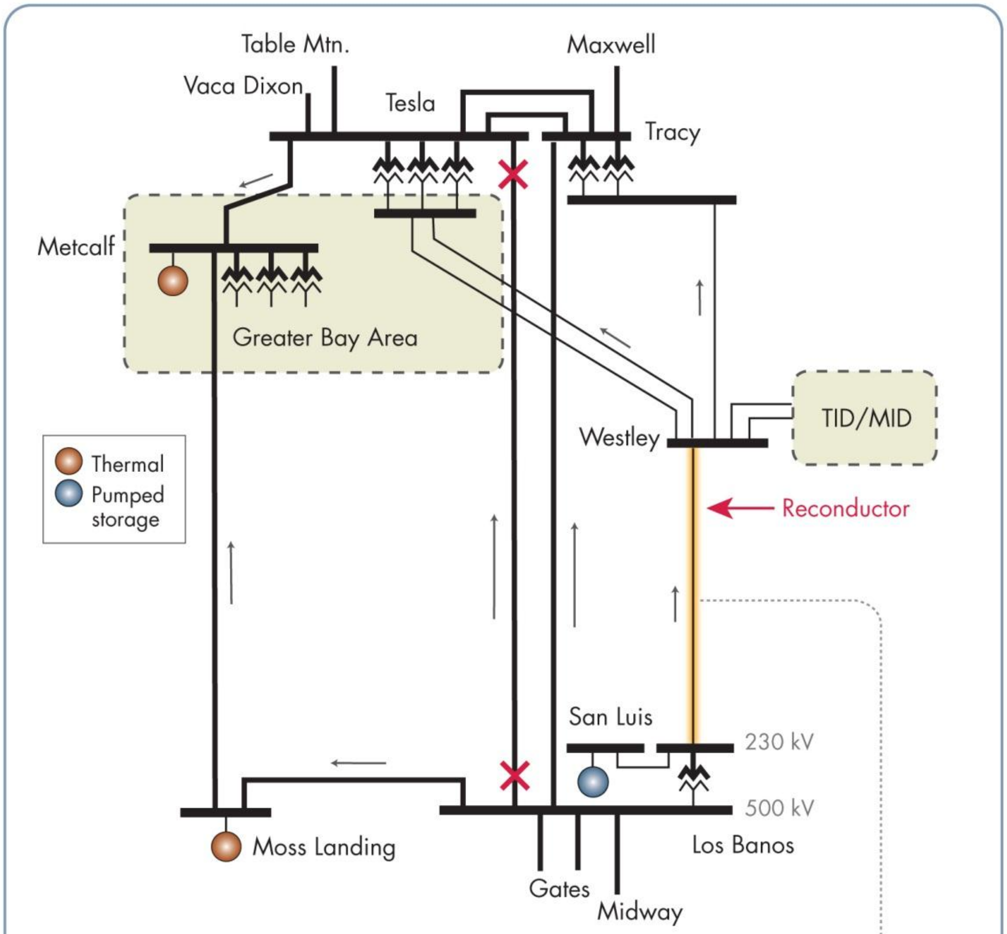
Figure 5.6-18: Congestion on the Los Banos-Westley 230 kV line





To mitigate the congestion on the Los Banos-Westley 230 kV line, this study evaluated four alternative mitigation plans and made economic assessment for each of the alternatives. Figure 5.6-19 shows the congestion mitigation effects and economic assessment.

Figure 5.6-19: Alternative 1: Reconductor Los Banos-Westley 230 line



Economic assessment

Yearly benefits		Total costs and benefits		
2016	2021	Cost	Benefit	BCR
$0M	$1M	$65M	$8M	0.12

Congestion hours

Before		After	
2016	2021	2016	2021
3	27	0	0

In the following, an economic assessment is made. Table 5.6-15 shows cost estimates for the proposed network upgrade. Table 5.6-16 lists quantified economic benefits. Table 5.6-17 provides a cost-benefit analysis.

Table 5.6-15: Cost estimates for congestion mitigation measure for LBN

Alt.	Description	Capital Cost	Total Cost
1	Reconductor Los Banos-Westley 230 kV line (~35 miles)	$45M	$65M

Table 5.6-16: Benefit quantification for congestion mitigation measures for LBN

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Reconductor Los Banos-Westley 230 kV line	2016	$0M	-	-	$0M	$8M
		2021	$1M	-	-	$1M	

Table 5.6-17: Cost-benefit analysis of congestion mitigation measures for LBN

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Reconductor Los Banos-Westley 230 kV line	$65M	$8M	($53M)	0.12

As seen from the above table, the economic benefit falls short in comparison with the cost of proposed reconductoring. Therefore, there is no economic justification for the proposed network upgrades.

5.6.5 Path 60 (Inyo-Control 115kV Tie)

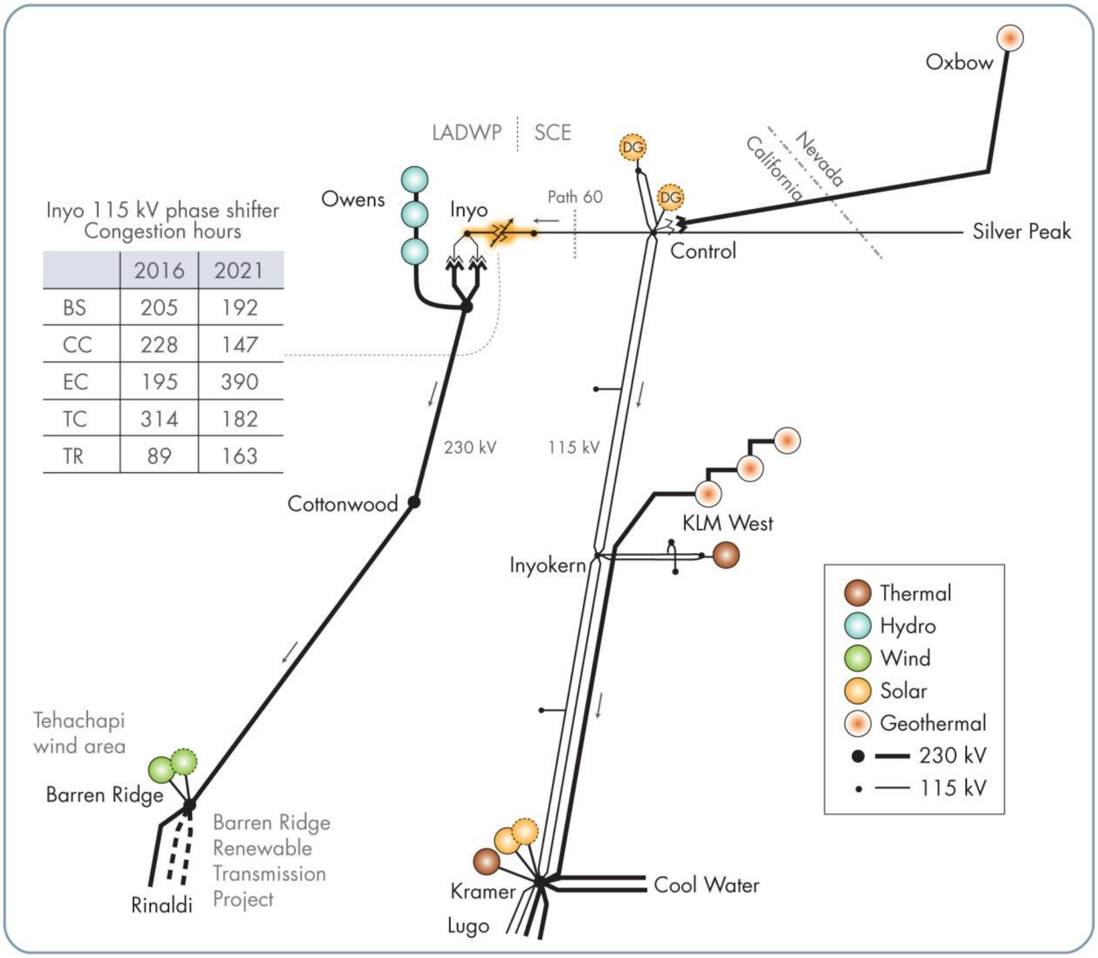
The Inyo area is a longitudinal system in the north SCE system. Table 5-6-18 lists the identified congestion on Path 60 in the Inyo area.

Table 5.6-18: Congestion identification in Inyo area — congestion hours and costs

#	Transmission Facilities	2016		2021	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Path 60 (Inyo 115 kV phase shifter)	205	0.110	192	0.113

Figure 5.6-20 shows Inyo system configuration and simulated Path 60 congestion under different RPS portfolios.

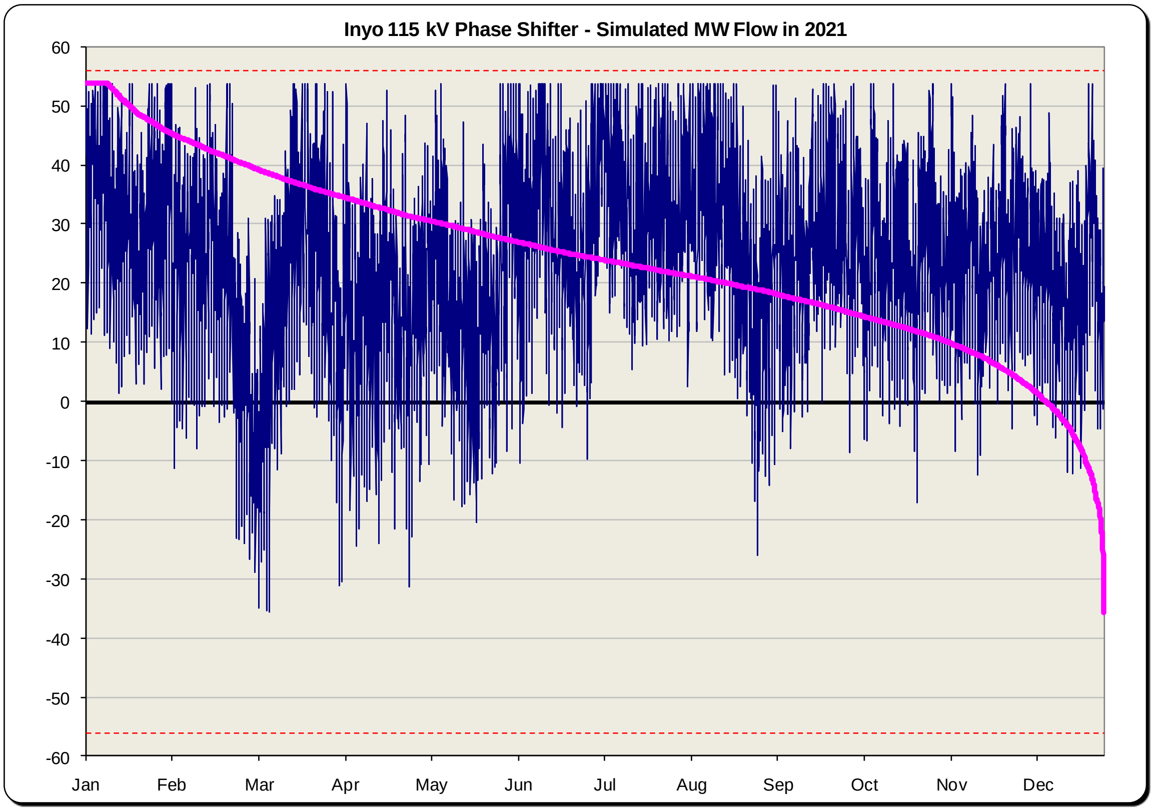
Figure 5.6-20: Inyo area system configuration and simulated congestion on Path 60



	2016	2021
BS	205	192
CC	228	147
EC	195	390
TC	314	182
TR	89	163

Figure 5.6-21 shows simulated power flow on the Inyo 115 kV phase shifter.

Figure 5.6-21: Simulated power flow on the Inyo 115 kV phase shifter



To alleviate the Path 60 congestion on the Inyo 115 kV phase shifter, this study evaluated three alternative mitigation plans and made economic assessment for each of the alternatives. Figure 5.6-22 through Figure 5.6-24 show the congestion mitigation effects and economic assessment.

Figure 5.6-22: Alternative 1: Increase Inyo phase shifter regulation range from ±30° to ±60°

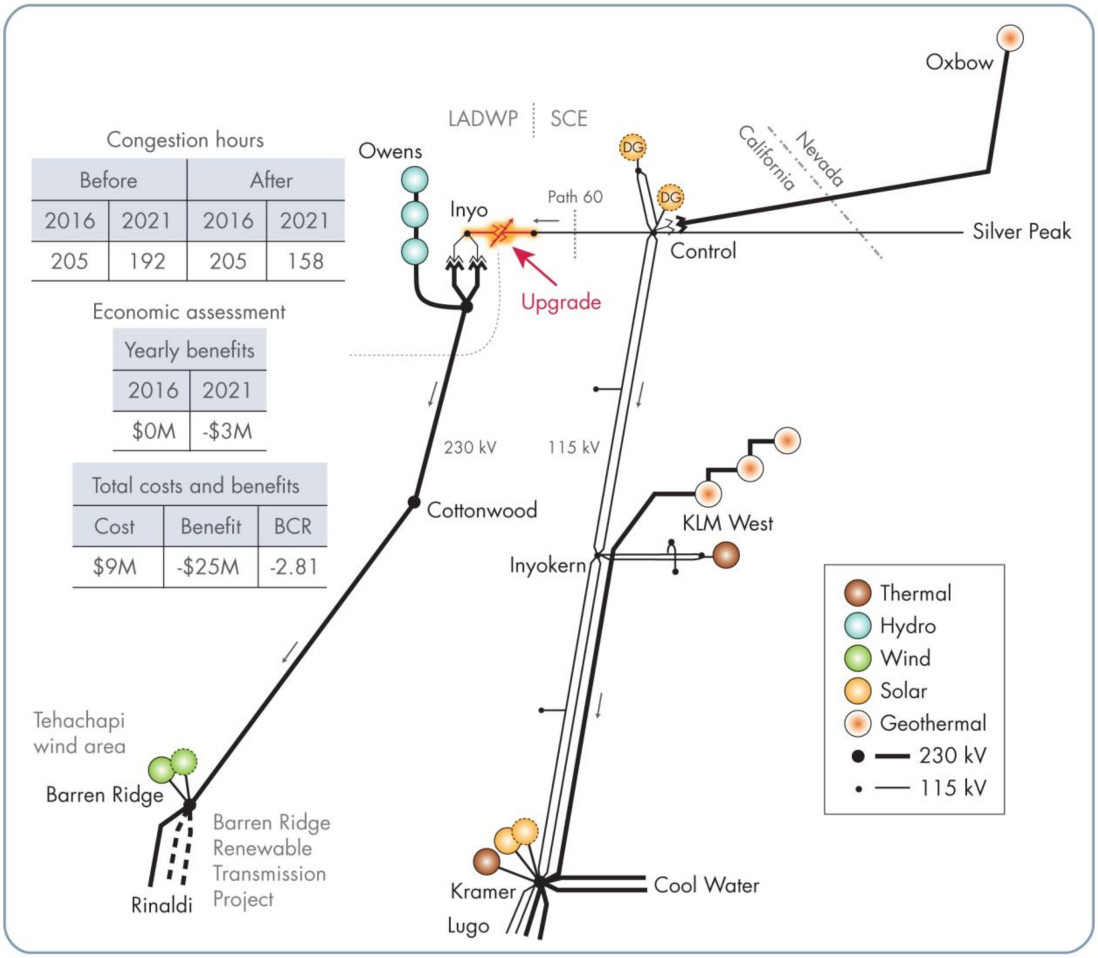


Figure 5.6-23: Alternative 2: Increase Inyo phase shifter capacity from 56 to 76 MVA

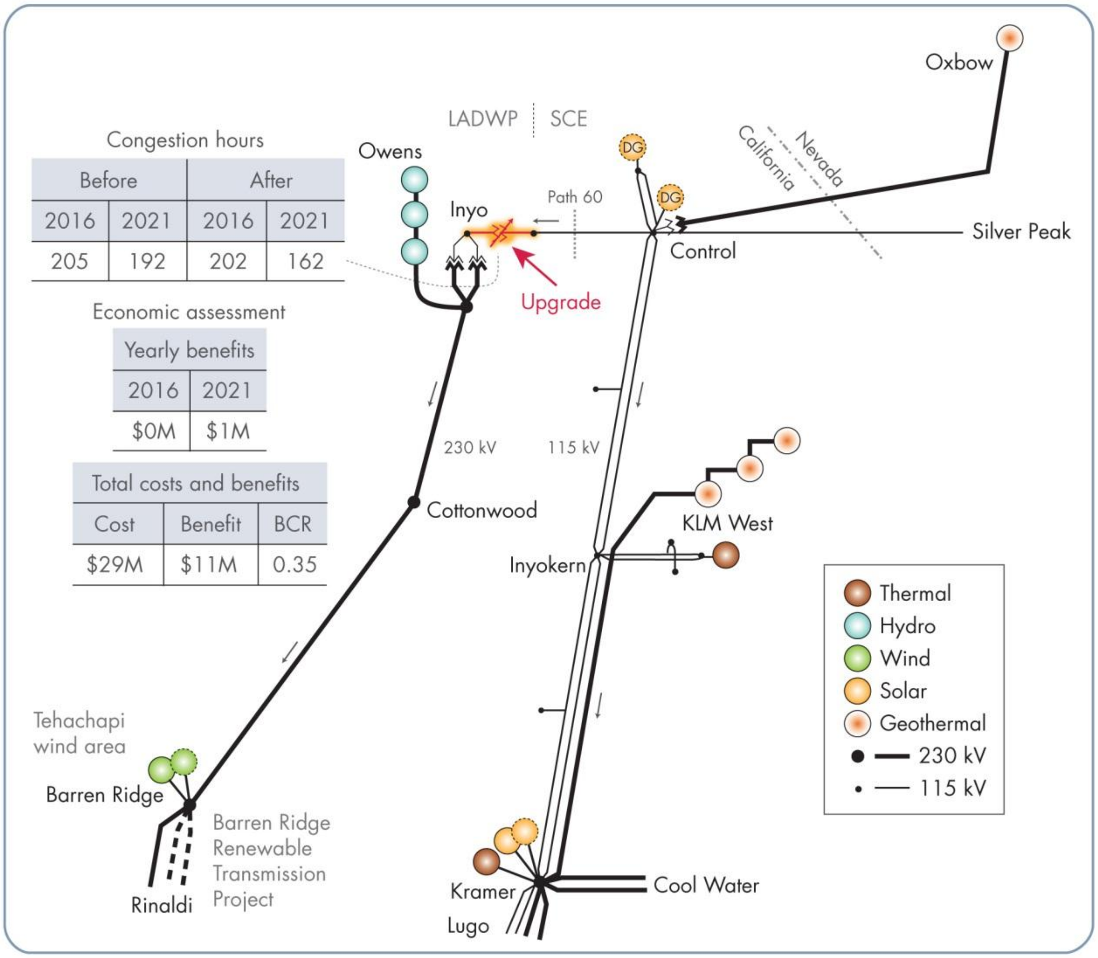
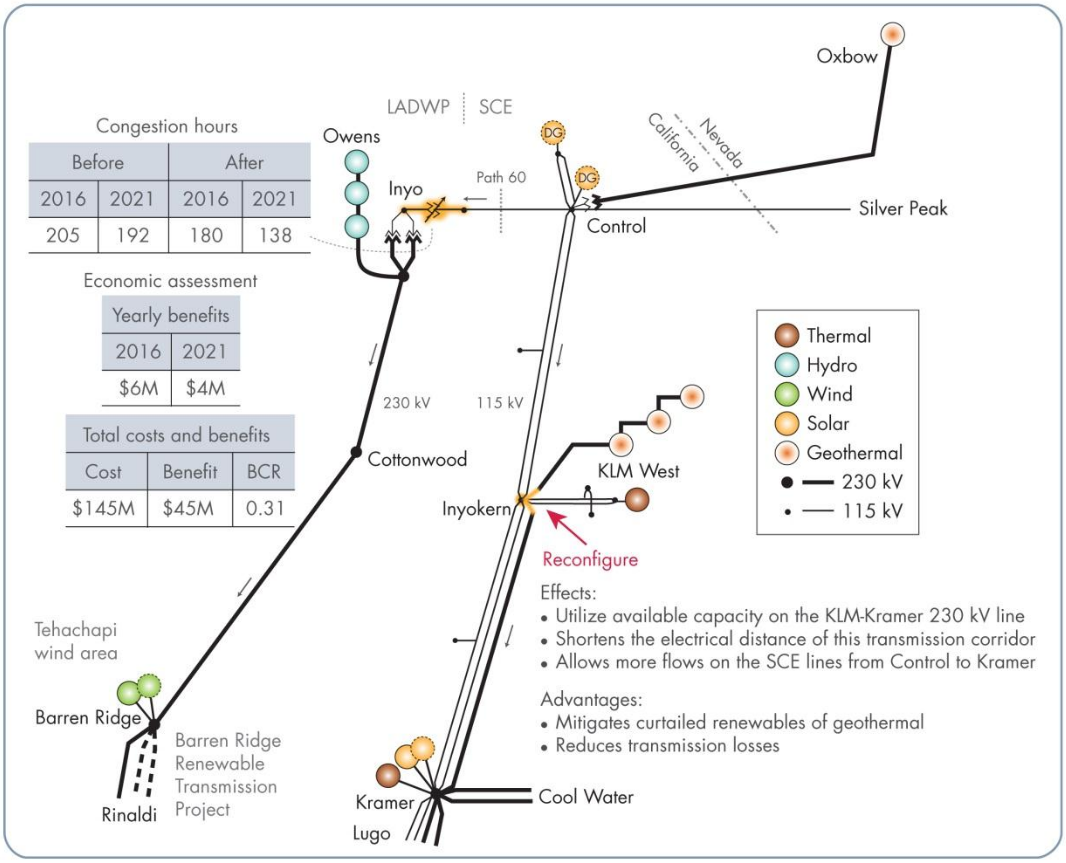


Figure 5.6-24: Alternative 3: Loop KLM West-Kramer 230 kV line into Inyokern



Chapter 4 made a power flow analysis of Alternative 2 on transmission losses reduction. Table 5.6-19 lists the amount of losses reduction under different RPS portfolios.

Table 5.6-19: Transmission losses reduction under peak and off-peak operating conditions

RPS Scenario		Operating Conditions	
ID	Name	2021 Peak	2021 Off-peak
BS	Base portfolio	10.9 MW	12.3 MW
EC	Environmentally constrained portfolio	18.6 MW	20.2 MW
TC	Time-constrained portfolio	12.5 MW	12.7 MW
TR	Trajectory portfolio	12.2 MW	13.2 MW

In this SCE transmission corridor, there is a small amount of load, while the predominant amount of generation is geothermal. The geothermal generators produce relatively constant output. Therefore, the transmission lines have relatively stable power flows; and the computed transmission losses are not very different between peak and off-peak conditions. With the computed transmission losses, the economic benefits of losses reduction can be estimated for the base case as follows:

$$\left(\frac{10.9\ + 12.3}{2}\right) \times 8760\ \times \left(\frac{56.16 + 66.28}{2}\right) = \$6{,}220{,}932 \cong \$6M$$

In the above formula, the first term is the average losses reduction in MW; the second term is 8,760 hours in a year; and the last term is the average of LMP's in year 2016 and 2021 calculated by the SCE area production simulation.

In the following, an economic assessment is made. Table 5.6-20 shows cost estimates for the proposed network upgrade. Table 5.6-21 lists quantified economic benefits. Table 5.6-22 provides a cost-benefit analysis.

Table 5.6-20: Cost estimates for congestion mitigation measures for Path 60

Alt.	Description	Capital Cost	Total Cost
1	Increase Inyo 115 kV phase shifter regulation from ±30° to ±60	$6M	$9M
2	Increase the rating of Inyo 115 kV phase shifter from 56 to 76 MVA	$20M	$29M
3	Build Inyokern 230/115 kV transformer and loop in the KLM West-Kramer 230 kV line	$100M	$145M

Table 5.6-21: Benefit quantification for congestion mitigation measures for Path 60

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Increase Inyo 115 kV phase shifter regulation from ±30° to ±60	2016	$0M	-	-	$0M	($25M)
		2021	($3M)	-	-	($3M)	
2	Increase the rating of Inyo 115 kV phase shifter from 56 to 76 MVA	2016	$0M	-	-	$1M	$10M
		2021	$1M	-	-	$1M	
3	Build Inyokern 230/115 kV transformer and loop in the KLM West-Kramer 230 kV line	2016	$0M	-	$6M	$6M	$45M
		2021	-$2M	-	$6M	$4M	

Table 5.6-22: Cost-benefit analysis of congestion mitigation measures for Path 60

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Increase Inyo 115 kV phase shifter regulation from ±30° to ±60	$9M	($25M)	($34M)	-2.81
2	Increase the rating of Inyo 115 kV phase shifter from 56 to 76 MVA	$29M	$11M	($18M)	0.35
3	Build Inyokern 230/115 kV transformer and loop in the KLM West-Kramer 230 kV line	$145M	$45M	($100M)	0.31

As seen from the above table, the economic benefit falls short in comparison with the cost of proposed reconductoring. Therefore, there is no economic justification for the proposed network upgrades.

5.6.6 Central Valley Area (CVA)

Table 5-6-23 lists study results of identified congestion in the Central Valley Area (CVA).

Table 5.6-23: Congestion identification in Central Valley Area — congestion hours and costs

#	Transmission Facilities	2016		2021	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Tesla-Weber 230 kV line, subject to loss of Tesla-Bellota 230 kV line	1	0.005	4	0. 045
2	Bellota-Weber 230 kV line, subject to loss of Tesla-Bellota 230 kV line	3	0.004	-	-
	Total:	4	0.009	4	0. 045

Figure 5.6-25 shows a system diagram of CVA in the Stockton area and simulated congestion under cases of different RPS portfolios.

Figure 5.6-25: Central Valley Area (CVA) system configuration and simulated congestion

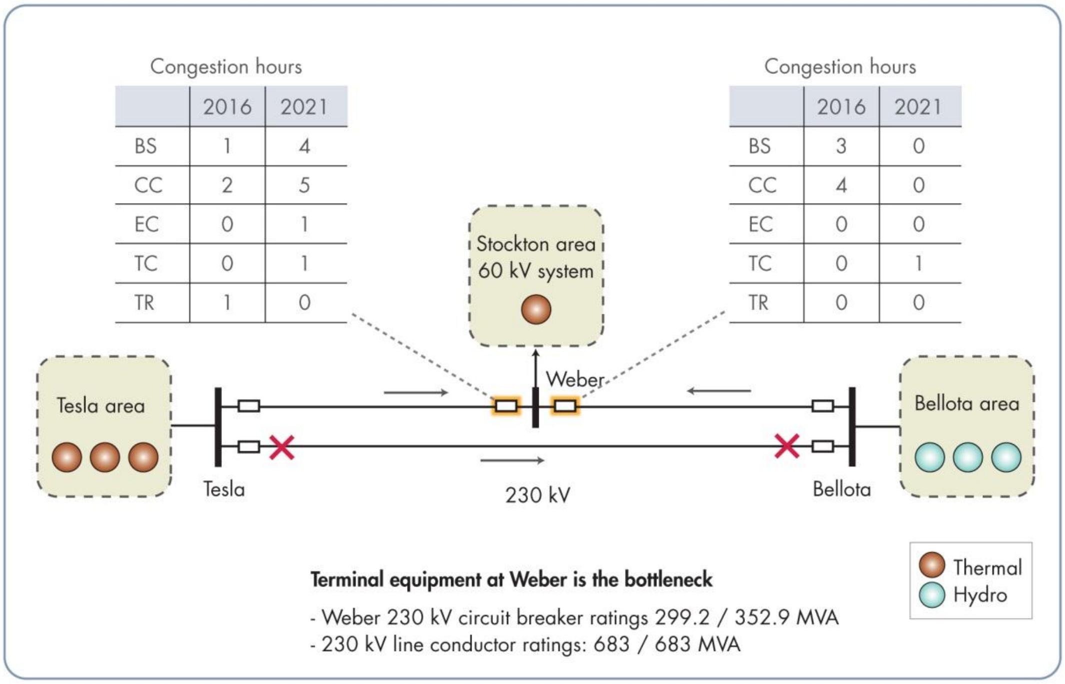
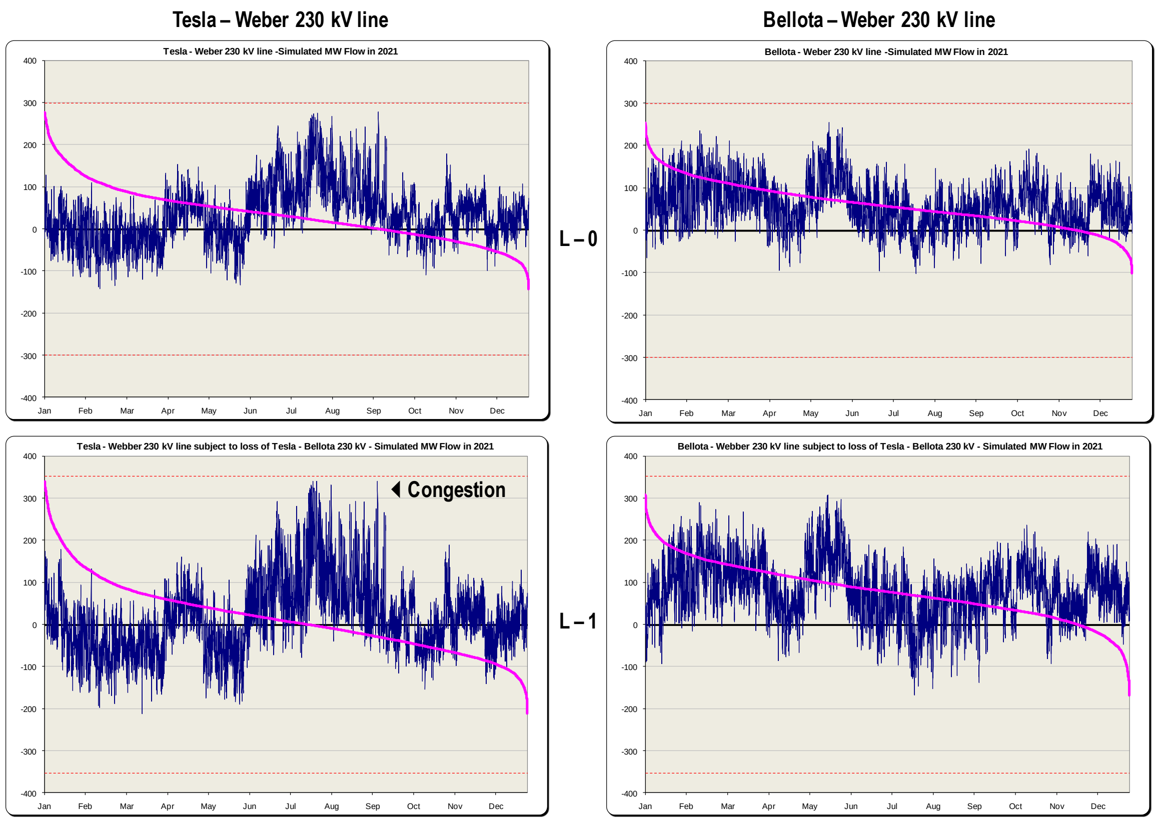


Figure 5.6-26 shows simulated power flow on the Tesla-Weber and Bellota-Weber 230 kV lines under normal condition and L-1 contingency with the loss of Tesla-Bellota 230 kV line.

Figure 5.6-26: Simulated power flow
on the Tesla-Weber and Bellota-Weber 230 kV lines under normal and L-1 conditions



To alleviate the CVA congestion, this study evaluated two alternative mitigation plans and made economic assessment for each of the alternatives. Figure 5.6-27 and Figure 5.6.-28 show the congestion mitigation effects and economic assessment.

Table 5.6-6 shows cost estimates for the proposed network upgrade. Table 5.6-7 shows quantified economic benefits. Table 5.6-8 provides a cost-benefit analysis.

Figure 5.6-27: Alternative 1: Replace Weber circuit breaker for the Tesla-Weber 230 kV line

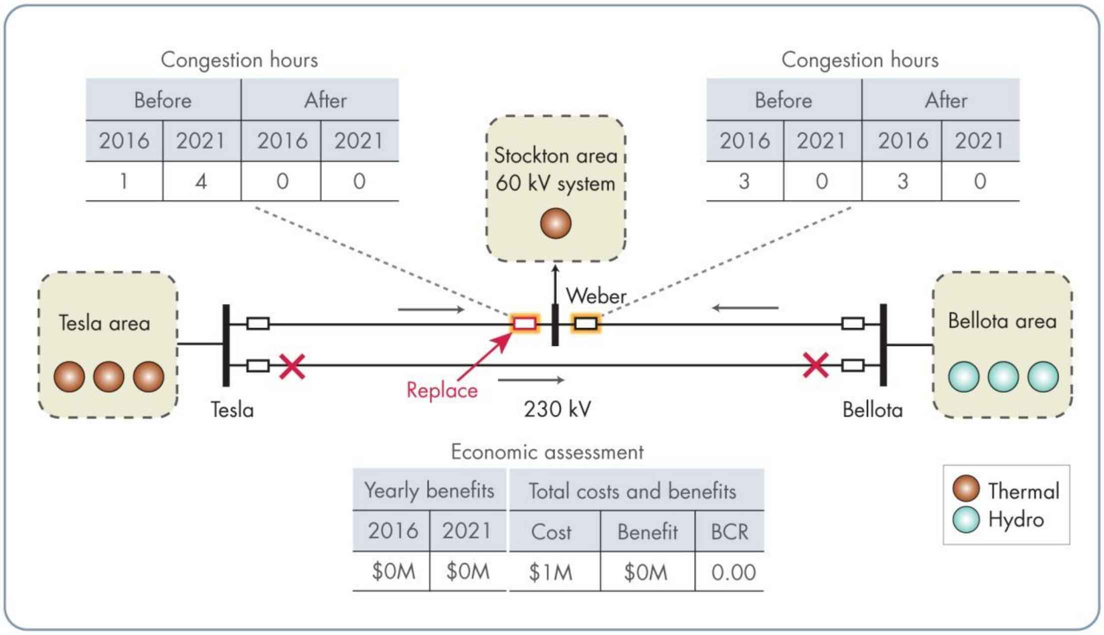
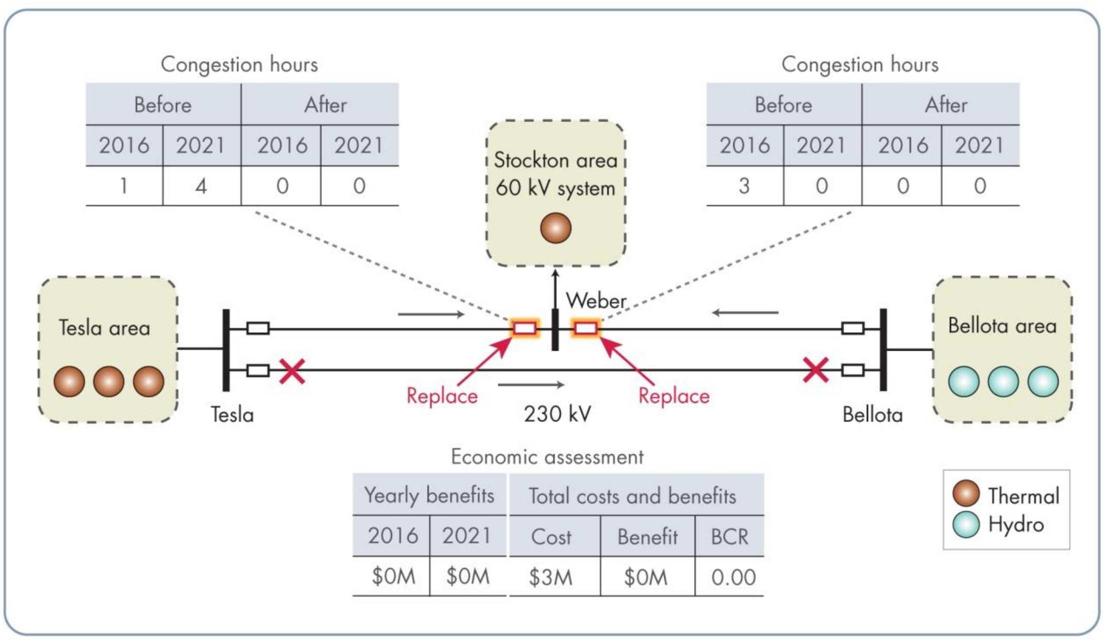


Figure 5.6-28: Alternative 2: Replace Weber circuit breakers for two incoming 230 kV lines



In the following, an economic assessment is made. Table 5.6-24 shows cost estimates for the proposed network upgrade. Table 5.6-25 lists quantified economic benefits. Table 5.6-26 provides a cost-benefit analysis.

Table 5.6-24: Cost estimates for congestion mitigation measures for CVA

Alt.	Description	Capital Cost	Total Cost
1	Replace Weber circuit breaker for the Tesla- Weber 230 kV line	$1M	$2M
2	Replace Weber circuit breakers for the two 230 kV lines from Weber and Bellota	$2M	$3M

Table 5.6-25: Benefit quantification for congestion mitigation measures for CVA

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Replace Weber circuit breaker for the Tesla-Weber 230 kV line	2016	$0M	-	-	$0M	$0M
		2021	$0M	-	-	$0M	
2	Replace Weber circuit breaker for the Tesla-Weber 230 kV line	2016	$0M	-	-	$0M	$0M
		2021	$0M	-	-	$0M	

Table 5.6-26: Cost-benefit analysis of congestion mitigation measures for Path 26

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Replace Weber circuit breaker for the Tesla–Weber 230 kV line	$2M	$0M	($2M)	0.00
2	Replace Weber circuit breakers for the two 230 kV lines from Weber and Bellota	$3M	$0M	($3M)	0.00

Based on the above analysis and results, the ISO has not identified any of the alternatives as needed.

5.7 Evaluation of Economic Planning Study Requests

Through the 2010 and 2011 Request Windows, the ISO received six Economic Planning Study Requests. The study requests are listed in Table 5.7-1.

Table 5.7-1: Study requests from the Request Window

Study ID	Study Subject	Submitted By	Request Window
SR1of6	Donnells-Curtis Reconductoring	PG&E	2010
SR2of6	North of Los Banos	PG&E	2010
SR3of6	Delany-Colorado River 500 kV	APS	2010
SR4of6	Imperial Valley Renewable Transmission Project	Citizen Energy Corporation	2010
SR5of6	Zephyr	TransCanada	2010
SR6of6	Midway-Gregg-Tesla 500 kV	PG&E	2011

In the above table, the first five items were labeled as “Economic Planning Study Requests” in the documents submitted by stakeholders. The sixth item was labeled as “Reliability / Other – Policy” by the stakeholder.

In the following sub-sections, evaluation of those study requests is described.

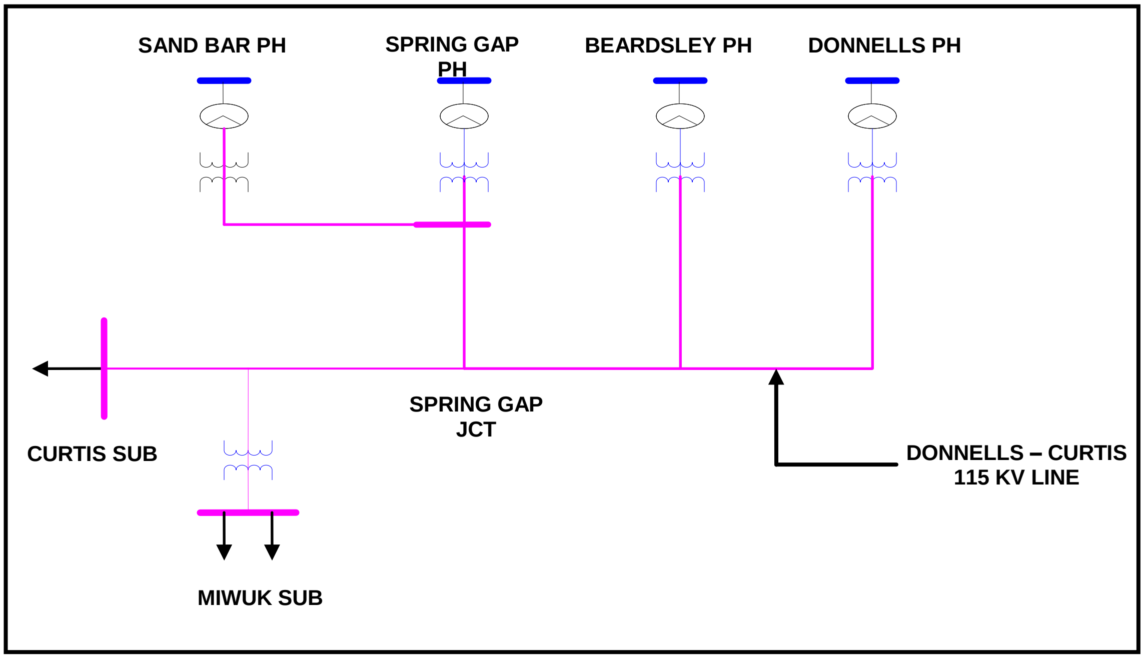
5.7.1 Donnells-Curtis Reconductor

This section provides general information about this study request, cites the benefits stated by the stakeholder, and presents ISO comments and clarifications.

5.7.1.1 Scope of the Study Request

The study request was to analyze congestion on the Donnells-Curtis 115 kV line from Spring Gap Junction to Miwuk Junction. Figure 5.7-1 shows a system diagram submitted by the stakeholder and the proposed line reconductoring.

Figure 5.7-1: System diagram for Donnells – Curtis Study Area



5.7.1.2 Benefits Described in the Study Plan

In the study request, the stakeholder stated the following:

"*Since MRTU go live, congestion has been observed on the Donnells-Curtis 115 kV Line from Spring Gap Jct to Miwuk substation. The congestion is seasonal and observed during spring run-off or under hydro spill conditions. The approximate congestion costs incurred on the line in 2009 and 2010 Day Ahead Market (DAM) is $823k and $286K respectively*."

Based on the above information, the stakeholder implied that by relieving the transmission bottleneck, the related hydro power plants would avoid hydro spills during spring runoff seasons.

5.7.1.3 The ISO's Evaluation

Historical data of market operations showed that congestion was severe in a wet hydro year (e.g. 2010). During the congestion, it is likely that the hydro plants will have to spill water. Water spillage is a waste of hydro energy. However, the congested radial line is not under ISO operational control.

The ISO does not have authority to approve or disapprove this matter. The ISO advises PG&E to make a determination on this matter.

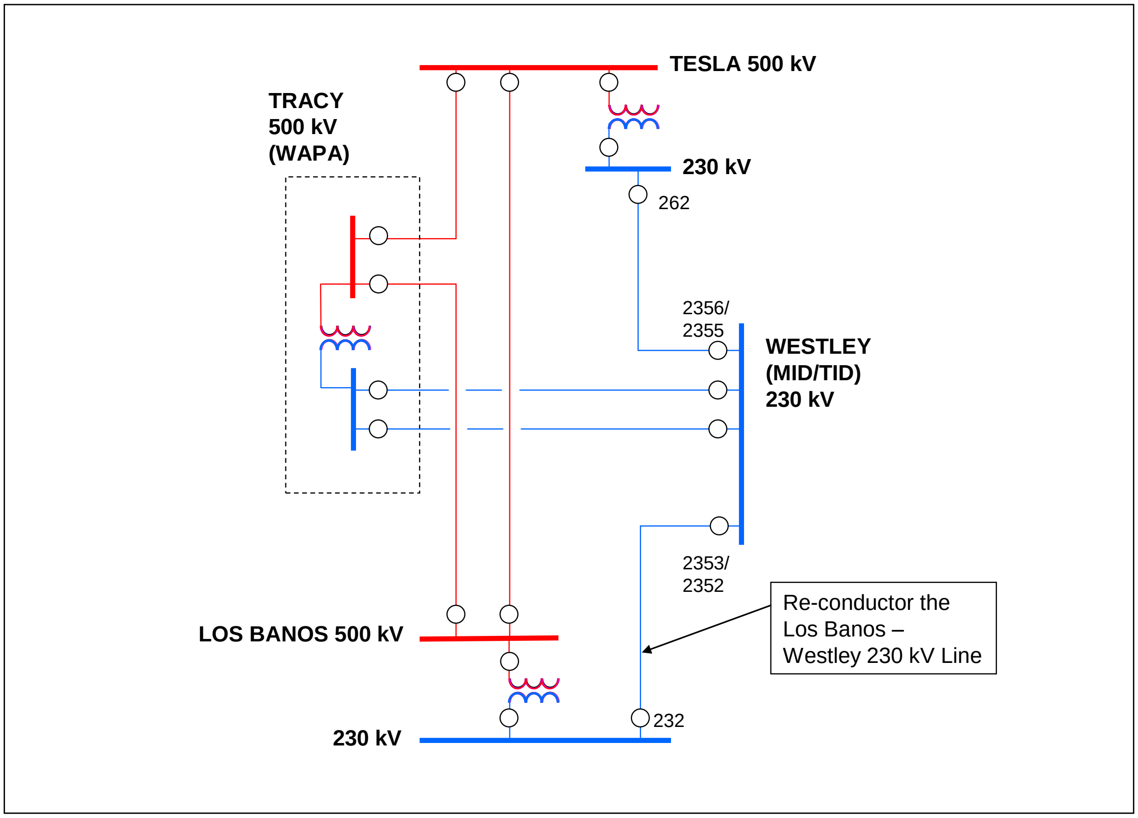
5.7.2 North of Los Banos

This section provides general information about this study request, cites the benefits stated by the stakeholder, and presents ISO evaluation.

5.7.2.1 Scope of the Study

The study request was to analyze congestion on the Los Banos-Westley 230 kV line. Figure 5.7-2 shows a system diagram submitted by the stakeholder and the proposed line reconductoring.

Figure 5.7-2: System diagram for "North of Los Banos" and the proposed line reconductoring



5.7.2.2 Benefits Described in the Study Request

The study request did not provide any descriptions of the potential benefits for the proposed reconductoring

5.7.2.3 The ISO's Evaluations

In assessment of policy needs, according to the studies described in Chapter 4, there is no indication of any problems in this transmission corridor to transmit renewables as defined in the RPS portfolios. Therefore, although this proposed transmission will facilitate transporting renewables, the proposed network upgrade is a help, but not a necessity for integrating the RPS resources.

This economic planning study requests is related to one of the congestion issues identified by the ISO. The Los Banos-Westley congestion was among the top-five congestion identified by this ISO congestion study, this subject was analyzed as one of the congestion mitigation studies. See Section 5.6.4 for details.

As the identified congestion was not severe (9 hours in 2016 and 18 hours in 2021), the quantified economic benefit was not large enough to exceed the cost of the proposed reconductoring. The conclusion is that there is not sufficient economic justification for the proposed network upgrade.

5.7.3 Delany-Colorado River 500 kV

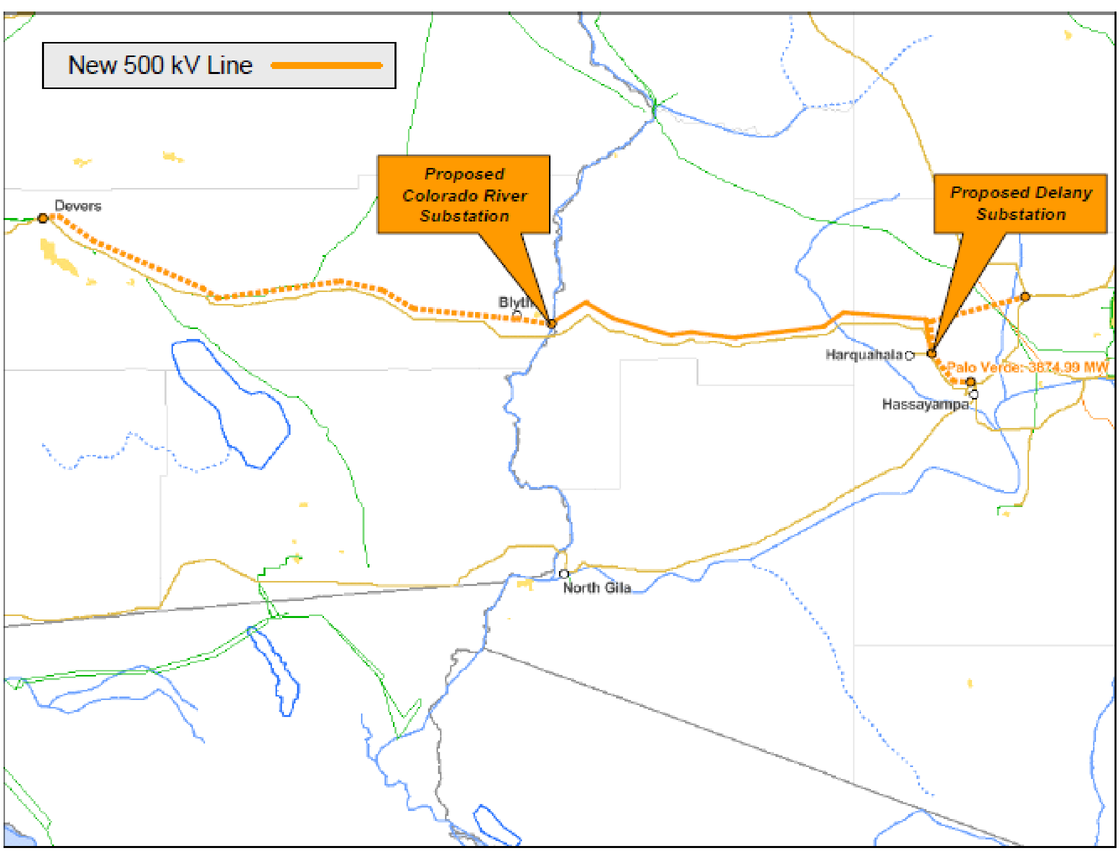
This section provides general information about this study request, cites the benefits stated by the stakeholder, and presents ISO evaluations.

5.7.3.1 Scope of the Study Request

This study request raised the issue of congestion between Palo Verde and the planned Colorado River Substation. The study request included a concept of building a new Delany-Colorado River 500 kV transmission line from Arizona to California. Such a line would begin at the APS-owned Delany 500 kV Substation, which is currently under construction. The potential line would end at the Colorado River 500 kV Substation, which is an ISO-approved new substation designed to loop into the existing Palo Verde-Devers 500 kV line.

Figure 5.7-3 is a system diagram submitted by the stakeholder in this study request.

Figure 5.7-3: System diagram for the AZ-CA bordering region and the proposed “Delany-Colorado River 500 kV”



5.7.3.2 Benefits Described in the Study Plan

The study request described a multitude of potential benefits for the potential line. The ISO notes the described benefits in the following table.

Table 5.7-2: Potential benefits of the Delany- Colorado River 500 kV

Category	Description
Market efficiency	The study request highlighted the congestion experienced on the Arizona-California interface, specifically affecting the Palo Verde-Devers #1 500 kV line. The study request used data from the ISO's 2008 and 2009 market monitoring reports as evidence of the congestion between the Arizona-California interface. The study request also used the DOE 2009 Congestion Study to emphasize the severity of congestion that affected Southern California. Thus, the study request suggested that the potential Delany-Colorado River 500 kV line would mitigate the congestion between Arizona and California.
Generation diversity	The study request stated: 1) the potential new line would facilitate transporting out-of-state renewables to California; 2) there are significant amounts of existing combined cycle and combustion turbine resources at or near the Palo Verde hub; and 3) at Delany, there are about 1,500 MW of proposed new generation active in the APS queue.
Reliability Need	The study request stated that the potential new line would increase availability of the transmission links between Arizona and California. Hence, the line would provide reliability benefits.
Generation retirement	The study request stated that the potential new line would provide economic benefit related to the potential retirements of once-through-cooling plants in California.

5.7.3.3 The ISO Evaluation

According to the published ISO market monitoring reports, the congestion frequency on the Palo Verde tie is shown in Table 5.6-26. The market data shows that the congestion on the Palo Verde tie is real and requires attention.

Table 5.7-3: PALOVRDE_ITC Congestion Frequency

Year	Day Ahead	Real Time	Reference
2009	26.9%	11.6%	2009 Market Issues & Performance Annual Report
2010	8.1%	2.9%	2010 Market Issues & Performance Annual Report

Based on production simulation and power flow models, the ISO quantified the economic benefits of the potential Delany-Colorado River 500 kV line. In addition, the ISO also studied an alternative of building North Gila – Imperial Valley 500 kV line #2.

In the following, an economic assessment is made. Table 5.7-4 shows cost estimates for alternative network upgrades. Table 5.7-5 lists quantified economic benefits. Table 5.7-6 provides a cost-benefit analysis.

Table 5.7-4: Cost estimates

Alt.	Description	Capital Cost	Total Cost
1	Build Delany- Colorado River 500 kV line (~110 miles)	$220M	$319M
2	Build North Gila-Imperial Valley 500 kV line #2 (~80 miles)	$231M	$580M

Table 5.7-5: Benefit quantification

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Build Delany- Colorado River 500 kV line	2016	$10M	$5M	$2M	$17M	$237M
		2021	$16M	$5M	$2M	$23M	
2	Build North Gila-Imperial Valley 500 kV line #2	2016	$2M	$5M	$0M	$7M	$93M
		2021	$4M	$5M	$0M	$9M	

Table 5.7-6: Cost-benefit analysis

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Build Delany- Colorado River 500 kV line	$319M	$237M	($82M)	0.74
2	Build North Gila-Imperial Valley 500 kV line #2	$464M	$93M	($371M)	0.25

Based on the above analysis and results, the ISO has not identified any of the alternatives as needed.

5.7.4 Imperial Valley Renewable Transmission Project (IVRTP)

This section provides general information about this study request, cites the benefits stated by the stakeholder, and presents the ISO evaluation.

5.7.4.1 Scope of the Study

The study request was to analyze congestion and other economic benefits that could be obtained by expanding the transmission system between North Gila, Imperial Valley, and Devers Substations.

5.7.4.2 Benefits Described in the Study Request

The study request stated the following:

"Upgrades in this study area would provide multifaceted electric transmission benefits for collecting and delivering the energy output of renewable generation located in the Imperial Valley to concentrated retail energy markets principally in Southern California. Also, because of its interconnections to other elements in Arizona and Nevada, it will also allow for the transmission of renewable energy from and to those areas.

Other benefits of IVRTP are: 1) to provide additional transmission capacity over the western interconnect between Arizona and California on a new transmission path between the North Gila and Imperial Valley substation; and 2) improve reliability of the ISO system through a new interconnection between the transmission facilities of SCE and SDG&E."

5.7.4.3 The ISO's Evaluation

In assessment of policy needs, according to the studies described in Chapter 4, there is no indication of any problems in this transmission corridor to transmit renewables as defined in the RPS portfolios. Although these network delivery upgrades are not needed with the 2011/2012 TPP portfolios, similar upgrades could be needed to support portfolios with more renewable generation in the Imperial Valley area.

In assessment of economic needs, the ISO conducted simulations and quantified the economic benefit of the proposed network upgrade. Then, a cost-benefit analysis was performed. The economic assessment is presented below. Table 5.7-7 shows cost estimates for the proposed network upgrade. Table 5.7-8 lists quantified economic benefits. Table 5.7-9 provides a cost-benefit analysis.

Table 5.7-7: Cost estimates

Alt.	Description	Capital Cost	Total Cost
1	Imperial Valley Renewable Transmission Project (IVRTP) (With two new 500 kV stations and three new 500 kV lines with a total length of about 176 miles)	$1,300M	$1,885M

Table 5.7-8: Benefit quantification

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Imperial Valley Renewable Transmission Project (IVRTP)	2016	$9M	$5M	$3M	$17M	$228M
		2021	$14M	$5M	$3M	$22M	

Table 5.7-9: Cost-benefit analysis

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Imperial Valley Renewable Transmission Project (IVRTP)	$1,885M	$228M	($1,657M)	0.12

As seen from the above table, there are no material benefits for any of the alternatives. There is no economic justification for the proposed network upgrades.

While the proposed network upgrade offers certain levels of economic benefit, the benefit falls short to exceed the cost. As a result, economic justification for the proposed network upgrade is not supported.

5.7.5 Zephyr

This section provides general information about the study request, cites the benefits stated by the stakeholder, and presents ISO comments and clarifications.

5.7.5.1 Scope of the Study Request

The study request is to assess the congestion and other economic benefits of a potential transmission line that would deliver 3,000 MW of wind energy from Wyoming to Eldorado Valley south of Las Vegas, Nevada. The request asked the ISO to conduct an economic study of the congestion between the Eldorado Valley and loads in Southern California in the time frame between 2016 and 2020. The request proposed that the ISO evaluate the impacts of adding a minimum of 3,000 MW of new renewable generation to the westward path capacity on Path 46 from the Eldorado Valley to Southern California load areas and determine the appropriate conceptual system additions necessary to alleviate the congestion.

5.7.5.2 Benefits Described in the Study Request

The study request stated the following:

- *"Such an upgrade would cost-effectively deliver 3,000 MW of new, clean, sustainable and renewable wind energy generation from the best wind resource in the Western United States to loads in the southwest, including California, Nevada and Arizona."*
- *"Would create over $9 billion in new renewable energy investment in the Western United States."*
- *"Firm delivery of Wyoming wind into California would substantially reduce the carbon footprint of needed, new generation resources in the Western Interconnection."*
- *"The terminus in the Eldorado Valley would create the opportunity for developing a major market hub for renewable energy and, potentially, the first-of-its-kind renewable energy trading and balancing hub in the United States."*

5.7.5.3 The ISO's Evaluation

This economic study request was to evaluate congestion between Wyoming and California. In determining whether to proceed with further analysis of this request, the ISO first examined the amount of congestion identified in the course of the congestion analysis. Based on the five portfolios that the ISO studied, there was no appreciable congestion between Wyoming and California. As a result, the ISO did not consider further analysis to be warranted. It is recognized that the study request was based upon specific renewable scenarios that does not align with the ISO's renewables portfolios, which leads to this result. For further future consideration of such scenarios, this generation would need to be reflected in the portfolios used for future planning cycles. The ISO encourages stakeholders to participate in the development of renewable portfolios for its 2012-2013 Transmission Plan, so that study assumptions can be aligned as much as can be with economic study requests.

5.7.6 Midway-Gregg-Tesla

This section provides general information about the study request, cites the benefits stated by the stakeholder, and presents ISO clarifications.

5.7.6.1 Scope of the Study Request

The study request is to evaluate the congestion and other benefits of upgrading the transmission system between Midway and Tesla 500 kV substations.

5.7.6.2 Benefits Described in the Study Request

The study request stated the following:

"This project is projected to improve transmission reliability in the region and increase the south-to-north transfer capability in the state, and, would transfer output from new renewable resources in southern California and central California region and assist in meeting the states renewable portfolio standard (RPS) goals."

5.7.6.3 The ISO Evaluation

The study request proposed new 500 kV transmission facilities that affect a wide area in Northern California. The area needs are multi-faceted and there are expected to be potential economic, policy, reliability and renewable integration benefits. The 2012/13 generation portfolios and a more complete renewable integration analysis need to be incorporated into the analysis. Thus, this study request will continue to be evaluated in the next planning cycle in the 2012/2013 transmission plan.

5.8 Summary

In this economic planning study, a simulation was conducted to identify transmission congestion in the ISO controlled grid. The identified congestion was tabulated and ranked by severity. Six high-ranking congestion issues were studied in detail with an economic assessment of proposed mitigation measures.

From the economic assessment of the six high-ranking congestion issues, no economic justifications were found for the studied congestion mitigation plans.

In addition to the above-mentioned congestion studies, this economic planning study also evaluated six Economic Planning Study Requests submitted by stakeholders through the 2010 and 2011 Request Windows. No economic justifications were found for the proposed network upgrades contained in the study requests.

Chapter 6

Other Studies and Results

6.1 Location Constrained Resource Interconnection Facilities (LCRIF)

6.1.1 Final Approval for Highwind LCRIF Project

The ISO received a request from SCE on August 9, 2011 asking for final approval of the Highwind location constrained resource interconnection facility so that it can commence construction on this project 90 days from the request date. The Highwind LCRIF includes a new 220 kV collector substation named Highwind and approximately 9.6 miles of a 220 kV transmission line between the Highwind Substation and the new 500/220/66 kV Windhub Substation. The Windhub Substation is not included in the scope of the LCRIF project but is included in the Tehachapi transmission project approved earlier by the ISO.

The ISO Board of Governors conditionally approved the Highwind LCRIF on May 18, 2009. Although the project cost was below $50 million, the level at which Board approval of transmission projects is necessary, the Board was required to certify the Tehachapi wind resource area as an energy resource area. Since the capital costs of the project remained below $50 million, final project approval can be provided by ISO management.

SCE provided the ISO with the updated transmission project cost, as well as the demonstration of commercial interest that is required by the ISO tariff for final approval. Based on the information provided, the Highwind LCRIF met the tariff criteria for final approval and could proceed to construction after 90 days from the approval date as specified by ISO tariffs. Following is a summary of the information provided to ISO staff in compliance with the tariff requirements for final LCRIF approval.

Requirements for Final Approval

Tariff Section 24.4.6.3.2(b) sets forth two criteria that must be met for an LCRIF project to obtain final approval.

A. Highwind LCRIF Capital Costs as a Percentage of Transmission Revenue Requirements

Section 24.4.6.3.2(b)(1) contains the first criteria:

(1) *The addition of the capital cost of the project to the High Voltage Transmission Revenue Requirement of a Participating TOs will not cause the aggregate of the net investment of all LCRIFs included in the High Voltage Transmission Revenue Requirements of all Participating TOs to exceed fifteen (15) percent of the aggregate of the net investment in all High Voltage transmission facilities reflected in their High Voltage Transmission Revenue Requirements.*

SCE provided a transmission revenue requirement estimate of $7.7 million for the project. Since this is the first LCRIF project, this number also represents the aggregated transmission revenue requirement value for all LCRIFs at this time. Based on FERC Docket No. ER11-3594, the most recent total high voltage transmission revenue requirements for all participating TOs under the ISO's operational control is approximately $1.344 billion. Therefore, the Highwind LCRIF comprises approximately 0.57 percent of the total high voltage transmission revenue requirement, well below the 15 percent ceiling for all LCRIF projects.

Demonstration of Commercial Interest

Tariff Section 24.4.6.3.2(b)(2) contains the second criteria for final approval, which requires a successful demonstration of commercial interest in 60 percent of the LCRIF capacity . The Highwind project is proposed to have a capacity of 1,150 MW, which is limited by the normal rating of the 500/220 kV transformer at the Windhub Substation. To meet the tariff requirements, commercial interest in 690 MW or more of the capacity must be demonstrated. Section 24.4.6.3.4 sets forth the ways in which commercial interest must be demonstrated:

(a) *The proponent's demonstration must include a showing that LCRIGs that would connect to the facility and would have a combined capacity equal to at least twenty-five (25) percent of the facility's capacity have executed Large Generator Interconnection Agreements (LGIAs) or Small Generator Interconnection Agreements, as applicable.*

Project Queue No. 132, with a total of 374 MW,[28] executed an LGIA with the ISO and SCE on August 4, 2011 with a requested effective date of August 9, 2011. This represents 32.5 percent of the project's total capacity and satisfies the LGIA percentage requirement of Section 24.4.6.3.4(a). The remaining minimum level of interest, up to the required 60 percent, must therefore meet the criteria in Section 24.4.6.3.4(b):

(b) *To the extent the showing pursuant to Section 24.4.6.3.4(a) does not constitute sixty (60) percent of the capacity of the LCRIF, the proponent's demonstration of the remainder of the required minimum level of interest must include a showing that additional LCRIGs:*

1. *Have obtained Site Exclusivity or paid the Site Exclusivity Deposit in lieu of Site Exclusivity, and*
2. *Have demonstrated interest in the LCRIF by one of the following methods:*

   i. *Executing a firm power sales agreement for the output of the LCRIG for a period of five (5) years or longer, or*
   ii. *In the case of Large Generating Facilities subject to the GIP set forth in Appendix Y, filing an Interconnection Request and paying the Interconnection Study Deposit; or*

[28] Project Queue No. 132 has a total capacity of 374 MW consists of 297 MW of new generation construction and transfer of an existing 77 MW of wind generation to the new Highwind 220kV collector substation.

iii. *In the case of Large Generating Facilities subject to the GIP, being in the ISO's interconnection queue and paying a deposit to the ISO equal to the sum of the minimum deposits required of an Interconnection Customer for all studies performed in accordance with the GIP, less the amount of any deposits actually paid by the LCRIG for such studies; or*

iv. *Paying a deposit to the ISO equal to five (5) percent of the LCRIG's pro rata share of the capital costs of a proposed LCRIF, in which the deposit shall be credited toward costs of Interconnection Studies performed in connection with GIP.*

The site exclusivity requirement (Section 24.4.6.3.4(b)[1]) has been met by all active interconnection requests in the ISO generation queue (see Tables 8.1 and 8.2 below). Table 8.1 has 349.5 MW of new generation, other than project queue No. 132, which is proposed to connect at the Highwind Substation (pre-Cluster 4 studies). Table 8.2 has 1,684 MW of new generation projects, submitted via queue Cluster 4, which is proposed to connect at the Highwind Substation. The total capacity amount of generators in Table 1 represents another 32.1 percent of the project's total capacity. Adding project queue No. 132 yields a total of 743.5 MW, or 64.6 percent of the project's total capacity.

In addition to meeting the site exclusivity requirement, generators must also demonstrate commercial interest by satisfying one of the four requirements of Section 24.4.6.3.4(b)(2). The information provided by SCE shows that the Section 24.4.6.3.4(b)(2)(ii) requirement has been satisfied by all of the generators shown on Table 1.

Conclusion

SCE has demonstrated that the two remaining requirements (cost impact on the ISO high voltage transmission revenue requirement and commercial interest by generators in 60 percent of the line's capacity) have been met for the Highwind LCRIF. Based on the information provided, the ISO deemed that SCE has satisfied the tariff requirements for final approval and is eligible to commence construction of the project within 90 days of the date of the approval letter from the ISO (August 29, 2011).

6.1.2 Imperial Valley LCRIF Project

An evaluation of need for the proposed Imperial Valley Location Constrained Resource Interconnection Facility (IV LCRIF) Project, submitted jointly in the 2010/2011 transmission planning Request Window by CE Red Island Energy LLC and 8minutenergy Renewables LLC was performed by the ISO. The project consists of a 37.33 mile, double circuit 230 kV line from SDG&E's Imperial Valley 500/230 kV substation to an area near the southern tip of the Salton Sea in Imperial County, CA. According to ISO tariff section 24.4.6.3.6, the ISO must find a need for a proposed LCRIF project before recommending it for conditional approval. Once the requirements for conditional approval are met, an LCRIF project is eligible for final approval if certain commercial interest requirements are met.

The proposed IV LCRIF triggers the ISO's overarching transmission planning policy objectives: 1) accessing sufficient renewable energy to participate in the ISO market and to achieve the state's 33 percent renewable energy goals; and, 2) ensuring that acceptable measures are in place or under development for imports from the Imperial Irrigation District to reasonably participate in the ISO market. These policy considerations were taken into account as part of the need determination, consistent with the tariff criteria. The evaluation focused on determining the overall relative ratepayer benefits and costs of interconnecting generation through the proposed LCRIF in comparison to connecting through a neighboring balancing authority's facilities. Because an LCRIF entails ratepayer upfront funding and continued funding of unsubscribed LCRIF capacity with ratepayers exposed to stranded investment costs if a substantial portion of the LCRIF capacity remains unsubscribed, significant ratepayer benefits would need to be demonstrated for the ISO to consider recommending approving the IV LCRIF.

In evaluating the costs and benefits of the proposed LCRIF, the ISO studied three different generation scenarios to address the range of uncertainty regarding the timing and sequencing of future generation development in the Imperial Valley. It was assumed that the proposed LCRIF could accommodate, at most, a maximum resource build-out of 1,400 MW, at which point the proposed LCRIF would be fully subscribed. It was also assumed that the LCRIGs require full deliverability.

Based on the ISO analysis, the ISO has concluded that it cannot recommend conditional approval of the proposed Project.

6.2 Long-Term Congestion Revenue Rights Feasibility Study

Consistent with Section 4.2.2 of the ISO Business Practice Manual for Transmission Planning Process and ISO Tariff Sections 24.1 and 24.4.6.4, the long-term congestion revenue rights (LT CRR) study involves creating a process for evaluating the feasibility of fixed LT CRRs under on-peak and off-peak conditions. The fixed CRRs are the long-term CRRs previously allocated under the LT CRR markets and executed during the 2009, 2010 and 2011 CRR annual allocation and auction processes.

6.2.1 Objective

The primary objective of the ISO LT CRR feasibility study is to ensure that any existing fixed LT CRRs allocated as part of the CRR annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the ISO-controlled grid network model during the same time horizon.

6.2.2 Data Preparation and Assumptions

The 2011 LT CRR study was performed using the base case network topology used for the annual 2012 CRR allocation and auction process. The regional transmission engineers (RTE) who are responsible for long-term grid planning incorporated all the newly ISO approved transmission projects in the study base case and performed a full AC power flow analysis to validate acceptable system performance across the 10-year planning horizon. These projects and system additions were then modeled in the base case network model for CRR applications. The modified base case was then used to perform the CRR market run simultaneous feasibility test (SFT) to ascertain the feasibility of the fixed CRR. The list of projects can be found in Section 8.2 of the 2010/2011 Transmission Plan.

In the SFT-based market run, all CRR sources and sinks from awarded CRR nominations were applied to the full network model (FNM). The FNM forms the core network model for the ISO locational marginal pricing markets. All applicable constraints were considered to determine the resultant flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60 percent of available transmission capacity. The fixed CRR of the transmission ownership rights and merchant transmission were also set to 60 percent. All prior LT CRR market awards were set to 100 percent. For the study year, the market run was set up for four seasons and two time-of-use periods. The study setup and market run are accomplished in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as save cases for further review and record-keeping.

A close collaboration between the ISO Regional Transmission Engineering Group and CRR team was required to ensure that all data used were validated and formatted correctly to be compatible with all pertinent applications and CRR SFT market environment. For the long-term CRR study, the CRR FNM DB53 network model was used. The following criteria were used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs:

- SFT is completed successfully; and
- The worst case base loading in each market run does not exceed 100 percent of enforced branch rating.

Overall, there are improvements on the flow of the monitored transmission elements.

6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- Base case network model data for long-term grid planning is prepared by the RTE Group The data preparation may involve the use of one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTEs model the approved projects and perform AC power flow analysis to ensure power flow convergence;
- RTEs review all newly approved projects for the transmission planning cycle;
- Applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team;
- The CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE; and
- The CRR team reviews results using user interfaces and displays, in close collaboration with the RTEs.

The input data and results are archived as save cases to a secured location.

Tables E-1 and E-2 in Appendix E show the loading levels of some selected transmission facilities and interfaces before and after the approved transmission projects were added. The SFT study shows general improvement in transmission facility loading after the transmission projects were added.

6.2.4 Conclusions

The SFT studies involved six market runs that reflected four three-month seasonal periods (i.e., January through December) and two time-of-use (i.e., on-peak and off-peak) conditions. The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as the newly approved transmission projects were added to the ISO-controlled grid and the CRR network model.

SECTION V: TRANSMISSION UPGRADES

Chapter 7

Transmission Project List

7.1 Transmission Project Updates

Tables 7.1-1 and 7.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility project or enhance economic efficiencies.

Table 7.1-1: Status of previously approved projects costing less than $50M

No	Project	PTO Area	Expected In-Service Date
1	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	May-12
2	Bay Meadows 115 kV Reconductoring	PG&E	Dec-12
3	Caruthers – Kingsburg 70 kV Line Reconductor	PG&E	May-13
4	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	May-14
5	Cayucos 70 kV Shunt Capacitor	PG&E	May-14
6	Clear Lake 60 kV System Reinforcement	PG&E	May-16
7	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	Mar-14
8	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	Jun-12
9	Corcoran 115/70 kV Transformer Replacement Project	PG&E	Dec-12
10	Cortina 60 kV Reliability	PG&E	May-13
11	Cortina No.3 60 kV Line Reconductoring Project	PG&E	May-13
12	Crazy Horse Switching Station	PG&E	Jan-14
13	Del Monte - Fort Ord 60 kV Reinforcement Project	PG&E	May-12
14	Divide Transmission	PG&E	Mar-12
15	East Nicolaus 115 kV Area Reinforcement	PG&E	Jun-13

No	Project	PTO Area	Expected In-Service Date
16	Evergreen-Mabury Conversion to 115 kV	PG&E	Aug-15
17	Fort Ord 60 kV Reinforcement	PG&E	Dec-12
18	Fulton 230/115 kV Transformer	PG&E	May-14
19	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	May-13
20	Garberville Reactive Support	PG&E	June-13
21	Gill Ranch Gas Storage 115 kV Interconnection	PG&E	May-11
22	Glenn #1 60 kV Reconductoring	PG&E	May-15
23	Gold Hill-Horseshoe 115 kV Reinforcement	PG&E	May-12
24	Half Moon Bay Reactive Support	PG&E	May-12
25	Hammer – Country Club 60 kV Switch Replacement	PG&E	May-12
26	Herndon 230/115 kV Transformer Project	PG&E	May-13
27	Hollister 115 kV Reconductoring	PG&E	Dec-12
28	Humboldt 115/60 kV Transformer Replacements	PG&E	Mar-14
29	Ignacio-San Rafael (Ignacio – San Rafael and Ignacio – Las Gallinas 115 kV Reconductoring)	PG&E	replaced
30	Jefferson-Stanford #2 60 kV Line	PG&E	May-12
31	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	May-15
32	Lakeville – Ignacio #2 230 kV Line Project	PG&E	Mar-12
33	Lemoore 70 kV Disconnect Switches Replacement	PG&E	May-13
34	Maple Creek Reactive Support	PG&E	Dec-15
35	Mare Island - Ignacio 115 kV Reconductoring Project	PG&E	Dec-13
36	Mendocino Coast Reactive Support	PG&E	Dec-14
37	Menlo 60 kV Reinforcement	PG&E	Dec-12
38	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	May-14
39	Metcalf-Evergreen 115 kV	PG&E	May-17

No	Project	PTO Area	Expected In-Service Date
40	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	May-15
41	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	May-13
42	Midway-Renfro 115 kV Reconductor	PG&E	May-12
43	Missouri Flat - Gold Hill 115 kV Line	PG&E	May-14
44	Monta Vista - Los Altos 60 kV Reconductoring	PG&E	May-12
45	Moraga Transformers #1 & 2 Capacity Increase	PG&E	Jun-12
46	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	May-13
47	Moraga-Oakland "J" SPS Project	PG&E	May-12
48	Morro Bay 230/115 kV Transformer Addition Project	PG&E	May-13
49	Mosher Transmission	PG&E	May-13
50	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	May-14
51	Newark – Ravenswood 230 kV Line	PG&E	May-14
52	Occidental of Elk Hills 230 kV Interconnection Project	PG&E	Jan-12
53	Oro Loma - Mendota 115 kV Conversion Project	PG&E	May-15
54	Oro Loma 70 kV Area Reinforcement	PG&E	May-15
55	Palermo – Rio Oso 115 kV Line Reconductoring – over $50M has Board approval	PG&E	May-13
56	Pease-Marysville #2 60 kV Line	PG&E	Dec-15
57	Pittsburg – Tesla 230 kV Reconductoring	PG&E	May-13
58	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-14
59	Pittsburg-Lakewood SPS Project	PG&E	Jul-12
60	Reedley-Dinuba 70 kV Line Reconductor	PG&E	May-14
61	Reedley-Orosi 70 kV Line Reconductor	PG&E	May-1
62	Rio Oso - Atlantic 230 kV Line Project	PG&E	May-16

No	Project	PTO Area	Expected In-Service Date
63	Rio Oso 115 kV Reactor	PG&E	May-15
64	Rio Oso 230/115 kV Transformer Upgrades	PG&E	May-17
65	San Leandro - Oakland J 115 kV Line Reconductoring	PG&E	cancelled
66	San Mateo and Moraga Synchronous Condenser Replacement	PG&E	May-15
67	San Mateo -Bay Meadows 115 kV Reconductoring	PG&E	Dec-12
68	Sanger-Reedley 70 kV to 115 kV Conversion Project	PG&E	May-12
69	Santa Cruz 115 kV Reinforcement	PG&E	May-14
70	Shepherd Substation	PG&E	Apr-13
71	Soledad 115/60 kV Transformer Capacity	PG&E	May-16
72	South of San Mateo Capacity Increase	PG&E	Mar-16
73	Stagg – Hammer 60 kV Line	PG&E	May-14
74	Stockton 'A' -Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	May-13
75	Table Mountain – Rio Oso 230 kV Line Reconductor and Tower Raises	PG&E	Jun-12
76	Table Mountain – Sycamore 115 kV Line	PG&E	May-15
77	Tesla 115 kV Capacity Increase	PG&E	Apr-12
78	Tesla-Newark 230 kV Path Upgrade	PG&E	May-13
79	Vaca Dixon - Lakeville 230 kV Reconductoring	PG&E	Jun-17
80	Valley Spring 230/60 kV Transmission Addition:	PG&E	May-13
81	Vierra 115 kV Looping Project	PG&E	May-14
82	Watsonville Voltage Conversion	PG&E	Jun-15
83	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	May-13
84	West Point – Valley Springs 60 kV Line	PG&E	Dec-12
85	Wheeler Ridge 230/70 kV Transformer	PG&E	May-12

No	Project	PTO Area	Expected In-Service Date
86	Wilson 115 kV Area Reinforcement	PG&E	May-15
87	Woodward 115 kV Reinforcement	PG&E	May- 15
88	Antelope 66 kV Circuit Breaker Upgrade	SCE	Dec-11
89	Bailey 66 kV Circuit Breaker Upgrade	SCE	Dec-11
90	Cross Valley Rector Loop Project	SCE	Apr-14
91	Devers 115 kV Circuit Breakers Upgrade	SCE	Dec-11
92	Devers-Coachella Valley 230 kV Line Loop	SCE	Dec-13
93	Devers-Mirage 115 kV System Split	SCE	Dec-12
94	East Kern Wind Resource Area 66 kV Reconfiguration Project	SCE	Jun-14
95	Frazier Park Voltage Support	SCE	Jun-13
96	Highwind Location Constrained Resource Interconnection Facility	SCE	Dec-13
97	Kramer 115 kV Circuit Breakers Upgrade	SCE	Dec-11
98	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-18
99	Method of Service for Wildlife 230/66 kV Substation.	SCE	Jul-15
100	Method of Service to El Casco 230/115 kV Sub	SCE	Mar-13
101	Path 42 and Devers – Mirage 230 kV Upgrades	SCE	Dec-13
102	Rector Static Var System (SVS) Project (Expand Rector SVS)	SCE	Dec-11
103	Victor #3 230/115 kV Transformer Bank	SCE	Dec-12
104	New 138 Tap: TL13835 Talega to San Mateo-Laguna Niguel	SDG&E	Jun-12
105	New 230/138 kV transformer: Miguel Substation	SDG&E	2011
106	New and/or Upgrade of 69 kV Capacitors	SDG&E	2011-2014
107	New Escondido-Ash 69 kV line TL6956	SDG&E	Dec-12
108	New Sycamore - Bernardo 69 kV line	SDG&E	Jun-15

No	Project	PTO Area	Expected In-Service Date
109	P01141: Reconductor TL13836, Talega – Pico	SDG&E	Jun-12
110	Reconductor TL663, Mission-Kearny	SDG&E	Jun-15
111	Reconductor TL670, Mission-Clairemont	SDG&E	Jun-15
112	Reconductor TL676, Mission-Mesa Heights	SDG&E	Jun-15
113	Reconductor TL6915, TL6924: Pomerado-Sycamore	SDG&E	Jun-12
114	Removal of Carlton Hills Tap-Sycamore reconfiguration	SDG&E	Dec-12
115	Shadowridge-Calavera Tap 138 kV upgrade	SDG&E	2011
116	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	Jun-13
117	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-13
118	TL6913, Upgrade Pomerado - Poway	SDG&E	2014
119	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	Jun-13
120	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	Jun-13
121	Upgrade Los Coches 138/69 kV bank 51	SDG&E	Jun-13
122	Upgrade TL13802D, Encina-Calavera Tap	SDG&E	2011
123	Upgrade TL667, Penasquitos - Del Mar #2 69 kV line	SDG&E	2011
124	Upgrade TL680A, San Luis Rey - Melrose Tap 69 kV line	SDG&E	2011
125	Upgrade TL6927, Eastgate-Rose Canyon	SDG&E	2011

Table 7.1-2: Status of previously approved projects costing $50M or more

No	Project	PTO Area	Expected In-Service Date
1	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	16-May
2	Fresno Reliability Transmission Projects	PG&E	2014
3	South of Palermo 115 kV Reinforcement Project	PG&E	14-May
4	Vaca – Davis Voltage Conversion Project	PG&E	15-May
5	Alberhill 500 kV Method of Service	SCE	14-Jun
6	Tehachapi Transmission Project	SCE	2015
7	Bay Boulevard Substation Project	SDG&E	14-Jun
8	Southern Orange County Reliability Upgrade Project - Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	17-Jun
9	Sunrise Powerlink	SDG&E	12-Jun

7.2 Transmission Projects Found to be Needed in the 2011/2012 Planning Cycle

In the 2011/2012 transmission planning process, the ISO determined that 30 transmission projects submitted through the 2011 Request Window were needed to mitigate identified reliability concerns. Table 7.2-1 is the summary of these 30 transmission projects. For a list of projects that came through the 2011 Request Window, refer to Appendix B.

Table 7.2-1: New reliability projects found to be needed

No	Project Name	Submitted By	Service Area	Type of Submission	In-Service Date	Cost
1	Borden 230 kV Voltage Support	PG&E	San Joaquin Valley	Reliability	2019	$15-20M
2	Cressey - North Merced 115 kV Line Addition	PG&E	San Joaquin Valley	Reliability	2016	$7-10M
3	East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project	PG&E	Greater Bay Area	Reliability	May-15	$15-30M
4	Embarcadero-Potrero 230 kV Transmission Project	PG&E	Greater Bay Area	Reliability	Dec-15	$130-150M
5	Geyser #3 - Cloverdale 115 kV Line Switch Upgrades	PG&E	North Bay/North Coast	Reliability	May-16	$1-3M
6	Helm-Kerman 70 kV Line Reconductor	PG&E	San Joaquin Valley	Reliability	2016	$2-4M
7	Humboldt - Eureka 60 kV Line Capacity Increase	PG&E	Humboldt	Reliability	May 2015 or sooner	$1-3M
8	Ignacio - Alto 60 kV Line Voltage Conversion	PG&E	North Bay/North Coast	Reliability	May-17	$35-45M

No	Project Name	Submitted By	Service Area	Type of Submission	In-Service Date	Cost
9	Kern PP 115 kV Area Reinforcement	PG&E	San Joaquin Valley	Reliability	May-16	$40-65M
10	Napa - Tulucay No. 1 60 kV Line Upgrades	PG&E	North Bay/North Coast	Reliability	May-14	$6-10M
11	New Bridgeville - Garberville No.2 115 kV Line	PG&E	Humboldt	Reliability	2018	$55-65M
12	North Tower 115 kV Looping Project	PG&E	Greater Bay Area	Reliability	May-15	$5-10M
13	Oakhurst/Coarsegold UVLS	PG&E	San Joaquin Valley	Reliability	2016	$2-5M
14	Oxy 115 kV Kern Front - Load Interconnection	PG&E	San Joaquin Valley	Reliability	Dec-11	$0.2-0.4M
15	Reedley 70 kV Reinforcement	PG&E	San Joaquin Valley	Reliability	2017	$7- 10M
16	Rio Oso Area 230 kV Voltage Support	PG&E	Central Valley	Reliability	May-16	$35-45M
17	Semitropic - Midway 115 kV Line Reconductor	PG&E	San Joaquin Valley	Reliability	2016	$15-20M
18	Taft 115/70 kV Transformer #2 Replacement	PG&E	San Joaquin Valley	Reliability	2016	$10-15M
19	Texaco BV Hills 115 kV - Load Interconnection	PG&E	San Joaquin Valley	Reliability	Dec-11	$0.5-0.7M
20	Tulucay 230/60 kV Transformer No. 1 Capacity Increase	PG&E	North Bay/North Coast	Reliability	May-14	$3-5M

No	Project Name	Submitted By	Service Area	Type of Submission	In-Service Date	Cost
21	Wheeler Ridge Voltage Support	PG&E	San Joaquin Valley	Reliability	2016	$25-40M
22	Del Amo - Ellis Loop In	SCE	LA Basin	Reliability	2013	$5-15M
23	Mesa & Antelope Breaker Upgrades	SCE	LA Basin & South of Magunden Areas	Reliability	Mesa 2012 & Antelope 2013	$3-5M
24	Tortilla 115 kV Shunt Capacitors	SCE	North of Lugo	Reliability	2013	$2-5M
25	Reconductor TL631, El Cajon - Los Coches	SDG&E	SDG&E	Reliability	2013	$17-22M
26	Replace Talega 138/69 kV Bank 50	SDG&E	SDG&E	Reliability	2015	$5-6M
27	TL633, Bernardo - Rancho Carmel 69kV:Reconductor	SDG&E	SDG&E	Reliability	2015	$11-13M
28	TL642B, Sweetwater - Montgomery Tap - Terminal Equipment	SDG&E	SDG&E	Reliability	2021	$0
29	TL695B, Talega Tap - Japanese Mesa Reconductor	SDG&E	SDG&E	Reliability	2016	$12-15M
30	Kern PP 230 kV Area Reinforcement	PG&E	San Joaquin Valley	Reliability	2016	$32-44

7.3 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for policy-driven and economic-driven transmission elements, as well as for reliability-driven elements that provide additional policy and economic benefits. Upgrades to or additions on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, and the construction or ownership of facilities within an existing participating transmission owner's substation are excluded from competition.

As noted previously in this transmission plan, the ISO has not identified any new policy-driven or economic-driven projects in the 2011/2012 transmission plan as needed.

The ISO then reviewed all reliability projects to determine if any elements produced sufficient additional policy or economic benefits such that the competitive procurement process should be applied.

FERC's ruling on the ISO's criteria for assessing whether reliability-driven elements demonstrated sufficient economic or policy benefits such that the competitive solicitation process should be implemented was received on February 1, 2011, and those criteria were applied in this evaluation.

The first step of the review was to identify any transmission elements identified as needed that did not constitute upgrades to or additions on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation.

In that review, the ISO identified two elements. Those two elements were the Embarcadero-Potrero 230 kV underground cable project and the Cressey-North Merced 115 kV transmission line identified in the plan and estimated to cost between $7 and 10 million.

In response to stakeholder comments, the ISO further considered that it would be appropriate to evaluate three voltage support projects as potential competitive solicitation candidates:

- Project # 1 - Borden 230 kV Voltage Support;
- Project # 16 Rio Oso Area 230 kV Voltage Support and Project; and
- Project # 21 - Wheeler Ridge Voltage Support.

Project #1 and Project #21 include mechanically switched capacitor banks, and Project #16 includes a Static Var Compensator. The ISO considered that it is debatable if the specific projects could in fact be reasonably and efficiently built outside of simply expanding existing substation facilities, but concluded it was more expedient to first consider if these three reliability driven projects provided additional policy or economic benefits.

The five elements from the five projects were evaluated for:

1. Additional policy benefits, which are demonstrated by considering if a policy project would need to be added or increased in scope if the reliability project did not proceed.
2. Economic benefits from congestion relief or transmission line loss savings produced by the project. The FERC-approved criteria call for the economic benefits to equal or exceed 10% of the cost of the project.

The transmission plan results for policy needs were reviewed for all five elements, and the ISO concluded that there were no policy benefits to any of the five transmission elements. None of the projects were in areas where the projects contributed to the interconnection of renewable generation.

The economic analyses for all five elements were based on the assessment of potential market congestion relief and transmission line loss savings. Table 7.3-1 illustrates the costs, benefits and benefit ratio per the FERC-approved criteria. These were assessed in a consistent manner as to the economic evaluation in Section 5 in determining the present value of savings.

If there was a potential for congestion relief, the results would be extracted from the production simulation analysis. Through a review of the system topology and the identified locations of potential market congestion, it was determined that none of the five elements produced market congestion benefits.

Transmission line loss savings were determined by studying peak and off peak power flow analysis, with and without the elements in service. Loss factors were determined to appropriately weight the results across 8760 hours in a year based on the local load factors for each project. Losses were valued at $61.54/MWh.

Table 7.3-1 Economic Analysis of Reliability Projects

No.	Project	Capital Cost $ millions	Total Cost (1)	Congestion Benefit	Loss Saving MWh	Loss Savings $ Millions	Cost Benefit Ratio (2)
1	Borden 230 kV Voltage Support	$11-15 (3)	16 - 22	0	2381	1.42	7%
2	Cressey-North Merced 115 kV Line Addition	$7 - 10	10 - 15	0	357	0.16	1%
4	Embarcadero-Potrero 230 kV Transmission Project	$130 - 150	189 - 218	0	0	0	0
16	Rio Oso Area 230 kV Voltage Support and Project	$35 - 45	51 - 65	0	4332	4.12	7%
21	Wheeler Ridge Voltage Support	$18 – 30(3)	26 - 44	0	357	0.21	1%

Note: 1 RR/CC ratio of 1.45 consistent with Section 5

2 Cost benefit ratio is based upon average Total Cost.

3. Costs reduced for portion of project on existing facilities or right-of-way

This analysis demonstrated that the projects did not provide additional policy benefits or economic congestion benefits meeting the criteria established by FERC, and the projects will therefore be developed by the incumbent participating transmission owner.

SECTION VI: APPENDIX

Appendix A – Reliability Assessment Results

Appendix B – 2011/2012 Request Window Projects

Appendix C – Policy-Driven Study Results

Appendix D – Identified Congestion Study Results

Appendix E – Long Term CRR-Based Transmission Loading