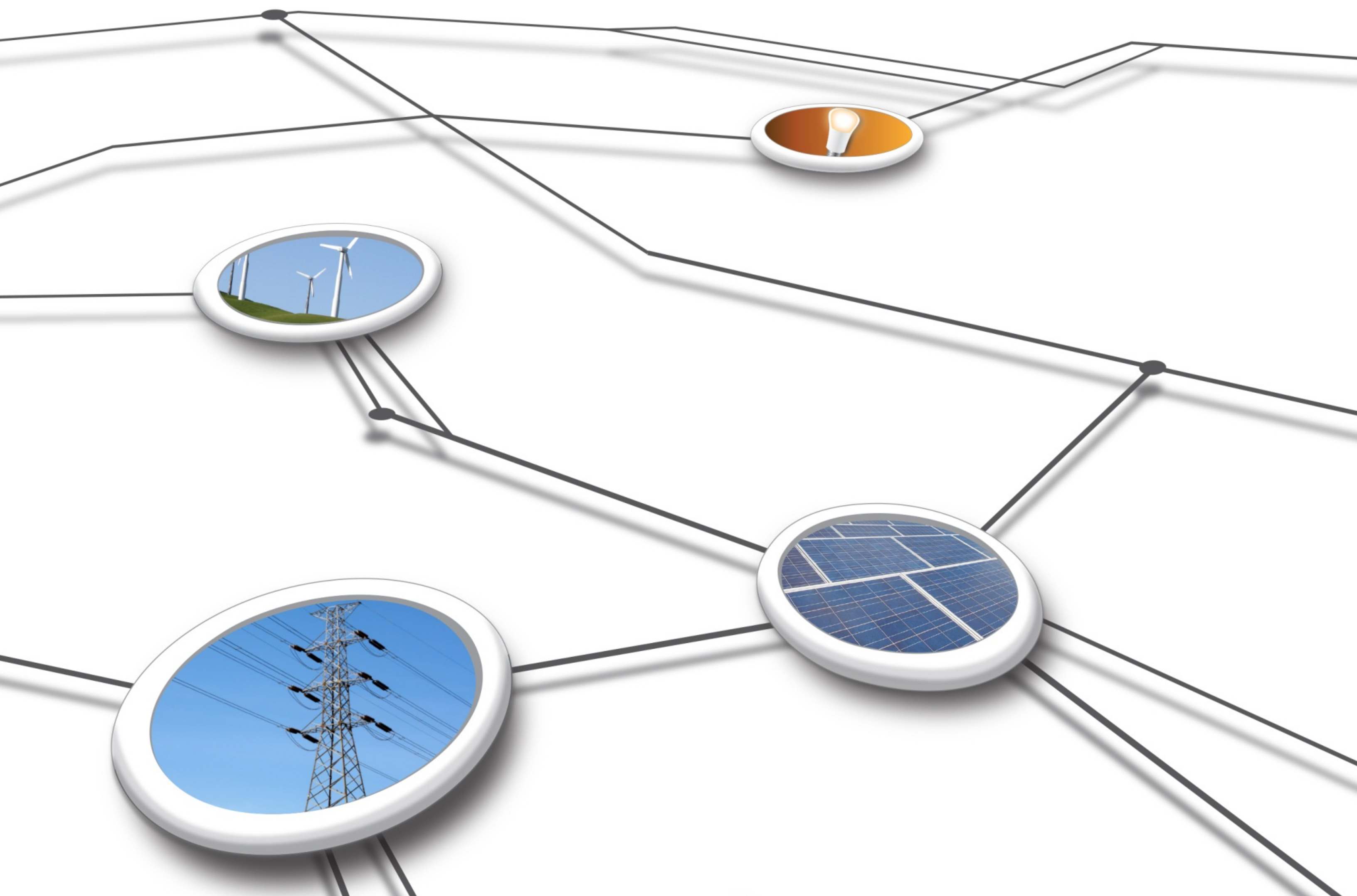
2012-2013
TRANSMISSION PLAN



California ISO
Shaping a Renewed Future

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Executive Summary

Introduction

The 2012-2013 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, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers. The ISO transmission grid expanded in 2013 when the Valley Electric Association joined the ISO. This plan is updated annually. In recent years, California enacted policies 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 RPS goals. Key analytic components of the plan include the following:

- identifying transmission needed to support meeting the 33 percent RPS goals 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;
- identifying 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 following key findings:

- The ISO identified 36 transmission projects with an estimated cost of approximately \$1.35 billion as needed to maintain transmission system reliability. Two of these mitigations were identified in the mid-term studies assessing potential mitigations for an unplanned long-term outage of both generating units at SONGS. Recognizing other potential benefits these projects may provide, the ISO is recommending these projects be approved;
- One service area, the San Francisco peninsula, has been identified by PG&E as being particularly vulnerable to lengthy outages in the event of extreme (NERC Category D) contingencies, and further studies have been initiated to determine the need and

[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 ISO tariff section 24.4.6.6.

urgency for reinforcement. Depending upon the results, this issue may be brought forward for consideration at a future Board of Governors meeting;

- Consistent with recent transmission plans, no new major transmission projects are required to be approved by the ISO at this time to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the California Public Utilities Commission approval process; however,
- Five smaller policy-driven transmission upgrades have been identified in this transmission plan, which the ISO is recommending for approval in this plan;
- The ISO has identified a potential policy- driven need, relating to potential overloads of the "West of River" transmission path leading into the ISO footprint from Arizona, under the base and sensitivity renewable generation portfolio, which the ISO discovered through review of the policy-driven maximum resource adequacy import capability analysis in draft Transmission Plan. This issue requires further study;
- One economically-driven 500 kV transmission project, the Delaney-Colorado River transmission project, which requires further study and, depending on the results of those studies, may be brought forward for consideration at a future Board of Governors meeting;
- One other economically-driven project, a 500 kV transmission line from Eldorado to Harry Allen, which provides significant potential benefits and which the ISO will evaluate further as part of an ongoing joint study with NV Energy and its consideration of possible transmission and non-transmission alternatives; and
- The ISO tariff sets out a competitive solicitation process for policy-driven 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.

  Based on the review conducted by the ISO, we have identified two elements eligible for competitive solicitation in this transmission plan:

  - Sycamore – Penasquitos 230kV Line ($111 - 211 million)
  - Gates-Gregg 230 kV Line ($115 - 145 million)

  Also, the Delaney – Colorado River project, which as previously discussed is being further reviewed, would be eligible for competitive solicitation as well if it is recommended for inclusion in the transmission plan later this year and approved by the Board. Some of the other areas identified for further study could also trigger additional needs that, if approved by the Board, could be eligible for competitive solicitation.

The ISO will continue to 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 renewable resource procurement beyond what was included in the renewable resource portfolios provided by the California Public Utilities

Commission (CPUC) and California Energy Commission (CEC) will need to be addressed in subsequent ISO transmission plans through the CPUC renewable energy procurement approval process to determine the specific location, quantity, and type of renewable energy projects.

This year's transmission plan is based on the ISO's transmission planning process, which involved collaborating with the California Public Utilities Commission, 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. The ISO amended its tariff to address those needed changes, and the Federal Energy Regulatory Commission (FERC) approved the ISO tariff amendments on December 16, 2010. 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 2011-2012 conceptual statewide transmission plan update on September 28, 2012, for application in the 2012-2013 transmission planning cycle.

The ISO has also taken major strides to better integrate the transmission planning process with the generation interconnection procedures. In July 2012, the ISO received FERC approval for the Generator Interconnection and Deliverability Allocation Procedures (GIDAP). The principal objectives of the GIDAP were to 1) ensure that, in the future, all major transmission additions and upgrades to be paid for by transmission ratepayers would be identified and approved under a single comprehensive process — the TPP — rather than some projects coming through the TPP and others through the generator interconnection process; 2) limit ratepayers' exposure to potentially costly interconnection-driven network upgrades that may not be most cost effective; and 3) enable the interconnection study process to determine meaningful network upgrade needs and associated cost estimates in a context where the volume of the interconnection queue vastly exceeds the amount of new generation that will actually be needed and built. The GIDAP is being applied to generator interconnection requests submitted into queue cluster 5 (submitted in March 2012) and will be applied to future queue clusters, while the provisions of the prior Generator Interconnection Procedures will still apply to interconnection requests submitted into cluster 4 and earlier.

Collaborative Planning Efforts

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

Transmission Planning Memorandum of Understanding (MOU)

An MOU on transmission planning 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. The agreed approach utilizes portfolios of generating resources, based on the CPUC's long-term procurement process (LTPP) and informed by the CEC's DRECP, that reflect potential generation development scenarios to meet the state's renewable mandate. The MOU calls for the ISO to consider and incorporate these generation scenarios into its transmission planning process and, where needed, identify policy-driven transmission additions or upgrades that will make these generation portfolios deliverable to load within the ISO. The CPUC, in turn, will give substantial weight in its siting and permitting process to transmission projects that are approved through the ISO's transmission planning process.

As discussed in more detail below, the CPUC in collaboration with the ISO produced the four generation scenarios studied in the 2012-2013 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. This policy will impact coastal generation that does not yet comply, by requiring that generation to be retrofitted, repowered, or retired. The ISO evaluated comprehensively the need for generation repowering or replacement related to the once-through cooled generation in the 2011-2012 transmission planning process. These study results were also submitted, with additional information, to the CPUC LTPP process in 2012.

Local reliability assessments in the LA Basin and San Diego LCR areas were further evaluated as part of the nuclear generation backup plan studies 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 California Air Resources Board (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 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 (i.e., CPUC, CEC, CARB) 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 past planning cycles the California ISO worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33% RPS by 2020. During their individual planning cycles, CTPG members completed a significant amount of technical analyses to develop a framework for preparing a statewide transmission plan. CTPG evaluates alternative renewable resource portfolios based on participant interest, which reflected input from RETI, other stakeholders, and state agencies. Their intent is to develop a conceptual least regrets transmission plan that CTPG members that are the planning entities for their balancing authority areas would assess in greater detail as part of their own respective planning processes. The CTPG produced its latest plan in March 2012, which was relied upon by the ISO in the development of a 2012 conceptual statewide plan for consideration in the 2012-2013 planning cycle.

Inter-regional Planning Requirements of FERC Order 1000

In July 2011, FERC issued Order No. 1000 on “Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.” The order required the ISO to make a filing demonstrating that the ISO is a qualified regional planning entity under the definition of the order, and modifying the ISO tariff as needed to meet the regional planning provisions of the order. It also required the ISO to develop and file common tariff provisions with each of its neighboring planning regions to define a process whereby each pair of adjacent regions can identify and jointly evaluate potential inter-regional transmission projects that meet their transmission needs more cost-effectively or efficiently than projects in their regional plans, and to specify how the costs of such a project would be assigned to the relevant regions that have selected the inter-regional project in their regional transmission plans. Given FERC’s approval of the ISO’s major revisions to its transmission planning process in the 2010 Revised TPP initiative, the ISO’s TPP was already largely compliant with the significant regional requirements of the order. Following a thorough stakeholder process the ISO filed the necessary tariff provisions for regional planning on October 11, 2012, as required. Filings for interregional planning are due on April 11, 2013.

To accomplish the requirements of interregional planning, the ISO has been collaborating for many months with the other three western planning regions: Columbia Grid, Northern Tier Transmission Group (NTTG) and WestConnect. Together the four regions, with the participation of their member transmission providers and other stakeholders, are developing common tariff provisions that the filing entities of all four regions will adopt. The new provisions will address sharing of planning information, reviewing each other’s regional plans, providing opportunities for member utilities, independent developers and the regions themselves to identify potentially viable and cost-effective interregional projects, and a common method for assigning the costs of a selected interregional project among all the regions to which it will interconnect. Additional information on the Order 1000 activities can be found on the ISO website.

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 2012-2013 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 these 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 approving 36 reliability-driven transmission projects, representing an investment of approximately $1.34 billion in infrastructure additions to the ISO controlled grid. The majority of these projects (28) cost less than $50 million and have a combined cost of $436 million. The remaining eight projects with costs greater than $50 million have a combined cost of $907 million and consist of the following:

- ***Atlantic-Placer 115 kV Line –*** A reinforcement and upgrade project of the 115 kV system within the Central Valley area of PG&E system to address a number of potential overload and voltage conditions in the area.
- ***Gates #2 500/230 kV Transformer Addition –*** The addition of a 500/230 kV transformer at the Gates substation to support the load in the Greater Fresno area of the PG&E system to address potential overload conditions in the area.
- ***Gates-Gregg 230 kV Line –*** The addition of a new 230 kV line into the Greater Fresno area of the PG&E system to address potential overload and voltage conditions in the area. The line also provides for expanded utilization of HELMS pump storage facility for ancillary service and renewable integration flexibility needs.
- ***Midway-Andrew 230 kV Project –*** A new 230/115 kV substation and 115 kV reinforcements and upgrades within the Central Coast and Los Padre area of the PG&E system to address a number of potential overload and voltage conditions in the area.
- ***Northern Fresno 115 kV Reinforcement –*** A new 230/115 kV substation and 115 kV reinforcements and upgrades within the Greater Fresno area of the PG&E system to address a number of potential overload and voltage conditions in the area.
- ***Lockeford-Lodi Area 230 kV Development –*** A 230 kV reinforcement and substation to supply the Lodi area within the Central Valley area of the PG&E system to address a number of potential overload and voltage conditions in the area.

- ***Install Dynamic Reactive Support at Talega 230kV Substation* –** The addition of dynamic reactive power source in the vicinity of Talega Substation to provide voltage support to the transmission system in the Orange County area.
- ***Orange County Dynamic Reactive Support* –** The addition of dynamic reactive power source in the vicinity of the SONGS switchyard to provide voltage support to the transmission system in the Orange County area.

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 1. Because Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) have lower voltage transmission facilities (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 Southern California Edison (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 1 – Summary of Needed Reliability-Driven Transmission Projects in the ISO 2012-2013 Transmission Plan

Service Territory	Number of Projects	Cost (in millions)
Pacific Gas & Electric (PG&E)	31	$1,168
Southern California Edison Co. (SCE)	0	0
San Diego Gas & Electric Co. (SDG&E)	5	$175
Valley Electric Association (VEA)	0	0
Total	36	$1,343

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 1 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.

One service area, the San Francisco peninsula, has been identified by PG&E as being particularly vulnerable to lengthy outages in the event of extreme (NERC Category D) contingencies, and further studies have been initiated to determine the need and urgency for reinforcement. Depending upon the results, this issue may be brought forward for consideration at a future Board of Governors meeting.

33 Percent 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. 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 chapters 4 and 5 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. A major enhancement in the development of the scenarios in this planning cycle was, with the support of the CEC, the incorporation of input from the Desert Renewable Energy Conservation Plan on environmental scoring into the scenario development. The CPUC proposed that one of these, the commercial interest scenario, be considered as a base case for ISO planning purposes, and the other three scenarios, the cost-constrained scenario, the environmentally-constrained scenario, and the high distributed generation scenario also be studied. In consultation with the

CPUC, the ISO further modified the commercial interest scenario based on stakeholder feedback to place further emphasis on potential development in Nevada to better reflect permitting requirements for projects connecting to the ISO in that state. 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, and resource financing capabilities were part of the metrics used to evaluate each portfolio.

In addition to transmission already approved by the ISO through the transmission planning process, 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.

Further, the ISO notes that within 2012, the ISO identified and received management approval of a small urgently-needed policy-driven transmission addition in the Imperial Valley area, the Imperial Valley Collector Station. The ISO is currently conducting an accelerated competitive solicitation process for this small policy-driven element.

The ISO assessment of the transmission projects identified above indicate that those projects with some additional smaller system upgrades are sufficient to meet the 33 percent RPS by 2020. These transmission upgrades were tested under the four generation portfolios and all of the projects identified in Table 2 below were determined to be needed and adequate for supporting energy delivery to load centers. Consequently, the ISO has concluded that no additional major upgrades are needed to be approved at this time to deliver renewable resources.

The ISO 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.

Also, in addition to the five upgrades discussed above, the ISO identified a potential policy-driven need relating to potential overloads of the “West of River” transmission path leading into the ISO footprint from Arizona. The ISO identified this potential need through its review of the draft Transmission Plan results for the base and sensitivity renewable generation portfolios. Since this issue has just recently been identified, it will require further study.

However, none of the projects evaluated in this transmission planning cycle qualified as Category 2 projects.

Table 2 provides a summary of the various transmission elements of the 2012-2013 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 2: Elements of 2012-2013 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Online
Transmission Facilities Approved, Permitted and Under Construction	
Sunrise Powerlink (completed)	2012
Tehachapi Transmission Project	2015
Colorado River - Valley 500 kV line	2013
Eldorado – Ivanpah 230 kV line	2013
Carrizo Midway Reconductoring	2013
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2015
South of Contra Costa Reconductoring	2015
Pisgah - Lugo	2017
West of Devers Reconductoring	2019
Coolwater - Lugo 230 kV line	2018
Policy-Driven Transmission Elements Approved but not Permitted	
Mirage-Devers 230 kV reconductoring (Path 42)	2015
Imperial Valley Area Collector Station	2015
Additional Policy-Driven Transmission Elements Recommend for Approval	
Sycamore – Penasquitos 230kV Line	2017
Lugo – Eldorado 500 kV Line Re-route	2020
Lugo – Eldorado series cap and terminal equipment upgrade	2016
Warnerville-Bellota 230 kV line reconductoring	2017
Wilson-Le Grand 115 kV line reconductoring	2020

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) 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 2017 (the 5th planning year) and 2022 (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, three economic study requests were submitted. Based on previous studied, identified congestion in the simulation studies, and the study requests, the ISO identified 5 high priority studies, which were evaluated in the 2012-2013 planning cycle.

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. The ISO's preliminary analysis was documented in the draft 2012-2013 transmission plan released on February 1, 2013, and indicated financial benefits exceeding costs for two projects. However, in the course of further reviewing those results, the ISO determined that the benefits for one of the projects (Delaney-Colorado River) may have been overestimated, primarily due to the treatment of greenhouse gas emissions relating to imports, and that the second project, Eldorado to Harry Allan, requires additional analysis and consideration of alternatives. Management therefore concluded the following:

- One economically-driven 500 kV transmission project, the Delaney-Colorado River transmission project, requires further study and, depending on the results, may be brought forward later this year for Board approval; and
- One other economically-driven project, a 500 kV transmission line from Eldorado to Harry Allen, has significant potential benefits, and the ISO will further evaluate it as part

of an ongoing joint study with NV Energy and the ISO's general consideration of possible alternatives.

Nuclear Generation Backup Plan Studies

Within the 2012-2013 Transmission Planning Process, the ISO examined the mid-term and long-term grid reliability impact in the absence of the two nuclear generating stations, Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), which are located in the ISO balancing authority.

The mid-term studies addressed the recommendations from the CEC, which were made in consultation with the CPUC, in the 2011 Integrated Energy Policy Report that "to support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and CEC) should report to the CEC as part of its 2013 Integrated Energy Policy Report (IEPR) and the CPUC as part of its 2013 long-term procurement plan on what new generation and transmission facilities would be needed to maintain system and local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde". The 2011 IEPR also recommended that the utilities "should report to the CPUC on the estimated cost of these facilities" (i.e., electrically equivalent replacement generation and transmission facilities). The study also incorporated once-through cooling policy implications for generating units that have compliance schedules up to the intermediate 2018 and longer 2022 time frames. The mitigation measures focus on actions that are reasonably implementable by summer 2018. This study identified several transmission system upgrades that, in addition to generation replacement and mitigation measures already underway, would assist in managing future unplanned extended outages to the SONGS plant. The upgrades included the following:

- install a total of 650 MVAR of dynamic reactive support (i.e., static VAR compensator or synchronous condensers) in the vicinity of SONGS and at the Talega or San Luis Rey Substations; and
- construct a Sycamore-Penasquitos 230 kV transmission line.

The 2022 study considered the reliability concerns and potential mitigation options in the long term. The study related to DCPP absence focuses on grid reliability implications for northern California and ISO overall. The study related to SONGS absence focuses on grid reliability implications for southern California and ISO overall. The combined DCPP and SONGS absence studies also focused on the grid reliability assessment for the ISO bulk transmission system. The results provided a range of options exploring the amount of generation and transmission required in the LA Basin and San Diego areas. This included considering different mitigation strategies, such as minimizing generation in San Diego, minimizing generation in the San Diego and LA basin areas overall, and utilizing some level of major transmission reinforcement to minimize reliance on local generation.

These results are presented in chapter 3.

These studies also took into account the steps being taken to prepare the system for the summer of 2013 that assumed that both SONGS units would remain unavailable:

- install one 79.2 MVAR capacitor bank each at Johanna and Santiago Substations, and two 79.2 MVAR capacitor banks at Viejo Substation;
- re-configure Barre-Ellis 230kV lines from two to four circuits; and
- convert Huntington Beach Units 3 and 4 to 2x140 MVAR synchronous condensers.

Since these studies included evaluations for potential transmission reliability concerns, other studies beyond grid reliability assessment would be needed to provide a more complete assessment and would include asset valuations, environmental impacts of green-house gas emissions, compliance with AB 32, impacts on flexible generation requirements, least-cost best fit replacement options, generation planning reserve margin, market price impacts, customer electricity rate impacts and impacts to natural gas systems for replacement generation. These issues are outside the scope of the ISO's transmission planning reliability study.

Conclusions and Recommendations

The 2012-2013 ISO transmission plan 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 41 transmission projects, estimated to cost a total of approximately $1,754 million, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits.

The transmission plan also identified four subjects which require further study, and which may result in management making further recommendations to the Board of Governors and seeking additional Board approvals of certain amendments to the 2012/13 transmission plan at a future meeting:

- addressing the potential need for transmission reinforcement of the San Francisco Peninsula due to outage concerns related to extreme contingencies,
- addressing potential overload concerns on the "West of the River" transmission path into the ISO footprint related to renewable generation in the Imperial Valley area,
- reviewing the economic benefits of a Delaney-Colorado River 500 kV transmission line addition, and
- reviewing the economic benefits of an Eldorado-Harry Allen 500 kV transmission line addition, once existing study work with NV Energy is completed and the ISO evaluates possible alternatives.

Chapter 1

1 Overview of the Transmission Planning Process

1.1 Purpose

A core ISO responsibility is to identify and plan the development of additions and upgrades to the transmission infrastructure that makes up the ISO controlled grid. Fulfilling this responsibility includes conducting an annual transmission planning process that culminates in a Board-approved, comprehensive transmission plan. The plan identifies needed additions and upgrades and authorizes cost recovery, subject to regulatory approval, through ISO transmission rates. This document serves as the comprehensive transmission plan for the 2012-2013 planning cycle.

The plan primarily identifies needed additions and upgrades based upon three main categories: reliability, public policy and economic. The plan may also include projects that are needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects or provide for merchant transmission projects.

The ISO identifies needed reliability projects to ensure the transmission system performance is compliant with all North American Electric Reliability Corporation (NERC) 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 2012-2013 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. The ISO identified mitigation plans to address any observed concerns that included upgrading transmission infrastructure, implementing new operating procedures and installing automatic special protection schemes. The planning process also provides an opportunity for interested parties to propose and for the ISO to consider other non-wire alternatives for addressing identified needs such as demand response and storage resources. ISO analyses, results and mitigation plans are documented in this transmission plan.[2]

Public policy-driven transmission additions and upgrades are those needed to enable the grid infrastructure to support state and federal directives. One such California law (AB32) requires 33 percent of the electricity sold annually in the state to be supplied from qualified renewable resources by the year 2020. Achieving this state policy requires developing substantial amounts of renewable generating resources, along with building new infrastructure to deliver their

[2] As part of efforts focused on the continuous improvement of the transmission plan document, the ISO has made one change in the documentation of study results in this year's plan. This document continues to provide detail of all study results necessary to transmission planning activities. However, additional documentation necessary strictly for demonstration of compliance with NERC and WECC standards but not affecting the transmission plan itself is being removed from this year's transmission planning document and compiled in a separate document for future NERC/FERC audit purposes.

electricity to consumers. The ISO's 2010-2011 transmission planning cycle was the first to include a public policy-driven category in recognition that the new transmission needed to support policies would unlikely qualify for approval based on the criteria defining other categories of transmission.

Economically-driven additions and upgrades are those that offer economic benefits to consumers that exceed their costs as determined by ISO studies, which includes a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses, as well as 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 with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. The 2012-2013 planning cycle, for example, began in January 2012 and concluded in March 2013.

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 is when the ISO performs studies to identify the needed transmission additions and upgrades that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months that ends with Board approval. Thus, phases 1 and 2 take 15 months to complete.

Phase 3 includes the competitive solicitation for prospective developers to build and own transmission elements in the economic 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.

In addition, specific transmission planning studies necessary to support other state or industry informational requirements can be incorporated into the annual transmission planning process to efficiently provide study results that are consistent with the comprehensive transmission planning process. The most significant example in the 2012-2013 planning cycle is the study of potential impacts and mitigations associated with future unplanned extended outages of one or both nuclear power generation stations, as well as the analysis of the longer term implications if those plants were not in-service.

1.2.1 Phase 1

Phase 1 generally consists of two parallel activities: 1) developing and completing the annual unified planning assumptions and study plan; and 2) developing a conceptual statewide transmission plan, which may be completed during phase 1 or phase 2. While the set of generating resource portfolios used to analyze public policy-driven transmission needs also would be developed as part of the unified planning assumptions in phase 1, in the 2012-2013 planning cycle resource portfolio development occurred in the first few months of phase 2. The ISO is working with the CPUC and stakeholders to implement process improvements so that all three activities can take place in phase 1 in the 2013-2014 planning cycle.

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 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 more recent element of transmission planning that the ISO added to its planning process in 2010. Planning transmission to meet public policy directives was adopted by FERC as 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 requirements or directives. The relevant policy directive for last two years' planning cycles and the current cycle is California's RPS that calls for 33 percent of the electricity consumed in the state in 2020 to 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. As discussed later in this section, the ISO's study work and determination of resource requirements for reliably integrating renewable resources is continuing on a parallel track. The implications of this effort on transmission planning go beyond the fundamental requirements of ensuring renewable energy resources are deliverable to load but at this time those implications cannot yet be identified.

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 requirements or directives such as California's RPS 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 or directives 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 California Transmission Planning Group (CTPG). Although the CTPG 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 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. Achieving the RPS 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 continues to be a great deal of uncertainty about which areas of the grid will actually realize most of this 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 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;
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 and 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 in 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, which is 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. performs economic studies, after the reliability projects and policy-driven elements have been identified, 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 meet state and federal policy requirements and directives, including renewable policies (policy-driven transmission elements); or 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 who meet the eligibility criteria 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 California's 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

[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. However, the criteria for this selection will change upon FERC's approval of the ISO's FERC Order 1000 regional compliance filing.

[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.

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 that might be needed to achieve the 33 percent RPS depending on future commercial interest in one of the renewable resource areas that did not feature significantly in the least regrets analysis. 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.

In 2012 there was considerable additional industry emphasis placed on the potential for non-transmission alternatives to meet the needs that would otherwise necessitate transmission development, particularly energy efficiency and demand side management programs. Though the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Within the 2012-2013 transmission planning cycle, the ISO has sought to increase public awareness of the opportunity to propose non-transmission alternatives for consideration in the phase 2 process, but received limited response. In 2013, the ISO will be exploring ways to enhance the consideration of non-transmission alternatives in its transmission planning process. .

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

[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 are included in the comprehensive plan as pre-approved by ISO management and not requiring further Board approval.

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 FERC's October 20, 2011 order in this regard. The FERC issued its ruling on the criteria on February 1, 2012.

The ISO evaluates the projects against its criteria prior to Board approval of the transmission plan. If eligible projects are determined and approved, 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. The ISO will then 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.

On October 11, 2012, the ISO filed its compliance filing with FERC Order No. 1000. This filing included revised provisions for determining which facilities are eligible for competitive solicitation. The ISO indicated in its filing that the competitive solicitation process could be modified to address the proposed revisions in the 2012-2013 planning cycle if the ISO's compliance filing was approved without material modifications by February 1, 2013. The ISO is awaiting a ruling on this filing and has applied the rules currently in effect.

1.3 Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012 the ISO received FERC approval for the GIDAP, which represents a major revision to the existing generator interconnection procedures to better integrate those procedures with the transmission planning process. The GIDAP is being applied to generator interconnection requests submitted into queue cluster 5 (submitted in March 2012), and will be applied to future queue clusters, while the provisions of the prior GIP will still apply to interconnection requests submitted into cluster 4 and earlier.

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

The principal objectives of the GIDAP (which was developed during a stakeholder initiative referred to as "transmission planning and generator interconnection integration" or "TPP-GIP Integration") were to ensure that, in the future, all major transmission additions and upgrades to be paid for by transmission ratepayers would be identified and approved under a single comprehensive process — the TPP — rather than some projects coming through the TPP and others through the GIP. It would also limit ratepayers' exposure to potentially costly interconnection-driven network upgrades that may not be most cost effective, as well as enable the interconnection study process to determine meaningful network upgrade needs and associated cost estimates in a context where the volume of the interconnection queue vastly exceeds the amount of new generation that will actually be needed and built.

The design of the GIDAP is based on the recognition that the biggest driver of costly interconnection network upgrades is the need to provide "deliverability status" to generating resources, which authorizes the resources to provide resource adequacy capacity to load-serving entities within the ISO and is critically dependent on grid capacity. On this basis the GIDAP accomplishes the above objectives by adopting, in the annual TPP, the planning objective to provide deliverability status for new generating resources in a total amount and geographic distribution corresponding to the base case resource portfolio the ISO uses in the TPP for purposes of identifying public policy-driven transmission additions and upgrades. In this way, the TPP will identify policy-driven upgrades to provide deliverability status to a generation portfolio that is consistent both in total volume and geographic distribution with how the state expects its LSEs to procure resources to meet their 33 percent RPS requirements. Such upgrades will then be paid for by ratepayers through the ISO Transmission Access Charge (TAC).

In order to limit ratepayer exposure to excessive interconnection-driven upgrade costs, the GIDAP further stipulates that generating resource that are unable to obtain deliverability status via the capacity approved under the TPP — because they represent a greater volume of new generation than the RPS portfolio requires or because they locate in areas not included in the portfolio — will have to fund their own delivery network upgrades without being eligible for cash reimbursement through the TAC.

In practical terms the impacts of the new GIDAP provisions are much greater to the generator interconnection rules and procedures than to the TPP. The primary impact to the TPP will come from including the planning objective of providing deliverability status to the base case 33 percent RPS generation portfolio. This will require the ISO planners to perform additional deliverability studies within the TPP, which in turn may result in the TPP identifying and including in the annual comprehensive transmission plan some public policy-driven transmission additions and upgrades that otherwise, would have been identified and approved under the GIP. Beyond that, the TPP is largely unaffected by the adoption of the GIDAP.

1.4 DG Deliverability

During 2012 the ISO worked with stakeholders to develop a streamlined, annual process for providing Resource Adequacy (RA) deliverability status to distributed generation resources from transmission capacity identified in the ISO's annual transmission plan. The proposal was approved by the ISO Board in May 2012 and filed with FERC in September. In November the FERC issued an order conditionally accepting the ISO's proposed tariff revisions subject to the submission of a compliance filing modifying the ISO's proposal. The ISO then identified some alternative approaches for complying with the required modifications, and initiated discussion with stakeholders to determine which would be the best approach. This effort is still in progress and, depending on which approach is ultimately preferred, it may not be feasible to perform the new process in time for the 2014 RA compliance year.

Under the new process, the ISO will annually perform two sequential steps, that include a deliverability study to determine nodal MW quantities of deliverability status that can be assigned to DG resources, followed by an apportionment of these quantities to load-serving entities for assignment to specific DG resources. FERC's order did not modify the deliverability study, so the ISO began its first deliverability study under this new process starting in December 2012 and expects to provide results in the latter half of February 2013. The ISO had intended to complete the first cycle of apportionment to LSEs by July 2013 so that LSEs would be able to assign deliverability status to DG resources in time to be effective for the 2014 RA compliance year. However, because FERC's order does modify the apportionment process and the optimal approach for complying is still under discussion with stakeholders, the first application of the results of the new process may have to wait until the 2015 RA compliance year.

In the first step of the process, the annual TPP will identify through a proposed new DG deliverability study, available transmission capacity to support deliverability status for distributed generation resources without requiring any additional delivery network upgrades to the ISO controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model to be used in the new DG deliverability study, the ISO will model the existing transmission system plus new additions and upgrades that have been approved in prior TPP cycles, plus existing generation and certain new generation in the ISO interconnection queue and associated upgrades. This will ensure that the nodal quantities of DG deliverability that result from the study can be made available without triggering additional delivery network upgrades or allowing "queue jumping" by utilizing available transmission capacity ahead of other generation projects earlier in the ISO or utilities' wholesale distribution access tariff (WDAT) queues. The DG deliverability study will use the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest TPP cycle for identifying public policy-driven transmission needs, both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that can be apportioned to load serving entities in the current cycle. This will ensure that the new DG deliverability assessment is aligned with the public policy objectives addressed in the current TPP cycle and precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the TPP.

In the second step of the process, the ISO will apportion the identified DG deliverability to load serving entities for their assignment of deliverability status to specific distributed generation resources. FERC's order on the proposal stipulated that FERC-jurisdictional load-serving entities must assign deliverability status to DG resources on a first-come-first-served basis, in accordance with the relevant interconnection queue. This first-come-first-served principle is a new element that FERC introduced into the proposal process, and has been the main focus of the ISO's discussions with its stakeholders. If the preferred approach can be determined fairly quickly, the ISO would still like to perform the apportioning process between March and July 2013 for use by load serving entities for 2014 RA.

Although this new DG deliverability process will be performed as part of the annual TPP, its only impact will be the addition of a new deliverability study to be performed in the latter part of Phase 2 of the TPP. This is expected to have minimal overall impact on the TPP.

1.5 FERC Order No. 1000

On October 11, 2012, the ISO filed revisions to the transmission planning process to comply with the regional planning requirements of FERC Order No. 1000. The ISO held a stakeholder process to address the regional requirements and develop tariff language which was approved by the Board in September. The ISO's transmission planning process was largely in compliance with the Order No. 1000 regional requirements as a result of the substantial changes implemented in the 2010/2011 planning cycle.[7] In particular, the ISO proposed the public policy-driven category for transmission upgrades and additions as part of its new planning process before FERC issued Order No.1000. The new planning process also expanded opportunities for independent transmission providers to compete for building economically-driven elements and certain transmission enhancements needed for reliability purposes if they also meet tariff criteria for public policy or economic projects. Additionally, as a regional planning entity, the ISO allocates the cost of high voltage transmission upgrades included in the Transmission Plan, which benefit the entire ISO region, to customers throughout the region; whereas, the costs of low voltage facilities, which provide primarily local benefits, are allocated to the participating transmission owner that builds them and recovers the costs from the customers that use them.

The ISO proposed tariff language in its Order No. 1000 compliance filing that includes the following:

- eliminates from the ISO tariff the remaining provisions that grant a federal "right of first refusal" for incumbent participating transmission owners for transmission upgrades or additions that are identified in the Transmission Plan as eligible for regional cost allocation;
- adds provisions clarifying that participating transmission owners have a right of first refusal to build and own local transmission facilities, which are facilities under 200 kV that are located within the retail service territory or footprint of the transmission owner;
- adds additional opportunities for stakeholders to propose public policy requirements and directives and also the ISO obligation to provide a public explanation of its selection of specific public policy objectives and the exclusion of others;
- establishes a "baseline" of public policy requirements and directives that will be carried over from one cycle to another;

[7] The ISO's revised transmission planning process (RTPP) was approved by FERC in December, 2010.

- clarifies the ISO's ultimate objective in its comparative analysis of the degree to which competing project sponsors meet the qualification and selection criteria;
- adds a new tariff requirement that the ISO identify within 30 days after posting the draft Transmission Plan, the factors and considerations that the ISO believes to be key drivers for selecting an approved project sponsor for elements that are open to competitive solicitation;
- adds a new tariff requirement that the ISO post within ten days after a project sponsor selection decision, a report detailing the results of the ISO's comparative analysis and the reasons for the ISO's decision;
- clarifies that the ISO will select the transmission or non-transmission solutions that are the most prudent and cost-effective;
- adds new project sponsor reporting requirements that allow the ISO to monitor progress of the status of new facilities; and
- adds a requirement that before the ISO re-assigns construction responsibility for a project that has been abandoned by a previously approved project sponsor, the ISO must conduct an additional competitive solicitation.

The ISO's regional Order No. 1000 compliance is pending before FERC.

1.6 Renewable Integration Studies

In the 2010-2011 LTPP, R.10-05-006, the ISO completed an initial study of renewable integration requirements under a range of future scenarios. This work identified in the trajectory scenario up to 4,600 MW of additional flexible resource capacity could be required beyond the projected existing fleet in 2020 after factoring in approved new generation and OTC retirements, but not taking into account local capacity requirements in transmission constrained areas. Based on the local capacity requirements study performed in 2012, the residual system needs for flexible resource capacity are about 1,250 MW, assuming identified local needs in San Diego, Los Angeles Basin and Big Creek Ventura are met by 2020.[8]

The interplay with potential generation development necessary to meet local capacity requirements in transmission-constrained areas with new generation or repowering of once-through cooling generation in coastal areas and the future of other once-through cooled coastal generation added considerable uncertainty to these study results. The CPUC has issued proposed decisions on local capacity resource needs in the San Diego, Los Angeles Basin and Big Creek Ventura areas but final decisions have not yet been reached.

Furthermore, the CPUC has not made a determination of need authorizing system generation in the Long Term Procurement Proceeding. As a result no specific flexible resources have been proposed to assess transmission adequacy or optimal grid location.

[8] The residual system needs are based on 2011 CPUC LTPP trajectory scenario that had 10% increase in load to account for potential higher load or underperformance of uncommitted demand programs but assume SONGS is available.

The ISO will therefore be performing additional analysis to consider cases with local capacity resources needed to meet local reliability needs to offset the retirement of OTC resources. In 2013, the ISO will perform updated fleet flexibility assessment studies using the 2012 updated CPUC LTPP scenarios and assumptions. In addition, the ISO expects to perform assessments of the resource adequacy fleet to assess whether the capacity and characteristics of the current resource adequacy fleet will be adequate to meet the changing flexibility needs of the system. Importantly, this resource adequacy assessment will consider only the resources under resource adequacy contract in order to capture the potential reality that resource capacity not under a resource adequacy contract will not be available because of a lack of sufficient revenues. The ISO will seek to incorporate these results into the 2013-2014 transmission planning cycle.

1.7 Non-Transmission Alternatives

Within 2012, considerable additional industry emphasis has been placed on the potential for non-transmission alternatives to meet the transmission system needs that would otherwise necessitate transmission development, particularly energy efficiency and demand side management programs. Though the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Within the 2012-2013 transmission planning cycle, the ISO has sought to increase public awareness of the opportunity to propose non-transmission alternatives for consideration in the phase 2 process, but received limited response. In 2013, the ISO will be exploring ways to enhance the consideration of non-transmission alternatives in its transmission planning process.

1.8 Nuclear Generation Backup Plan Studies

The ISO prepared studies in 2012 assessing the impacts on the transmission system of future unplanned and long term outages to the two nuclear generating stations in California, as well as the impacts of future retirement of both stations. The studies addressed the recommendations from the CEC, which were made in consultation with the CPUC in the *2011 Integrated Energy Policy Report* that “to support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and the CEC) should report to the Energy Commission as part of its 2013 IEPR and the CPUC as part of its 2013 Long-Term Procurement Plan on what new generation and/or transmission facilities would be needed to maintain system and/or local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde”. The *2011 Integrated Energy Policy Report* also recommended that the utilities “should report to the CPUC on the estimated cost of these facilities” (i.e., electrically equivalent replacement generation and/or transmission facilities). These studies are set out in Chapter 3.

The ISO has noted that several mitigations identified in these studies may provide benefit in addressing the current and potential future outage of the San Onofre Nuclear Generating Station. For example, mitigation options under consideration are additional dynamic reactive support in the SONGS and Talega areas and a new Sycamore-Penasquitos 230 kV transmission line in the SDG&E system. The dynamic reactive support could provide near-term benefits for addressing the current SONGS outage if current efforts to convert Huntington Beach units 3 & 4 to synchronous condensers are not successful and would provide longer-term benefits (with or without the Huntington Beach synchronous condensers) for mitigating any future long-term outage of SONGS. A new Sycamore-Penasquitos 230 kV transmission line has also been identified as an alternative to policy-driven transmission projects that would otherwise be needed to meet state RPS. The ISO has therefore recommended these mitigation options for approval in this year's plan.

Chapter 2

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 the following:

- 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.

This 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. The Western Electricity Coordinating Council (WECC) full-loop power flow base cases provide the foundation for the study. The detailed reliability assessment results are given in Appendix B and Appendix C.

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

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system;
- Southern California — Southern California Edison (SCE) system; and
- Southern California — San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. These assessments were performed on the regional planning areas within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories. These areas are listed below:

- PG&E regional areas:

  - o Humboldt;
  - o North Coast and North Bay;
  - o North Valley;
  - o Central Valley;
  - o Greater Bay Area;
  - o San Joaquin Valley Area; and
  - o Central Coast and Los Padres.
- SCE regional areas:
  - o Metro;
  - o Tehachapi and Big Creek Corridor;
  - o Antelope-Bailey;
  - o North of Lugo;
  - o East of Lugo; and
  - o Eastern
- SDG&E area
- VEA area

2.2 Reliability Standards Compliance Criteria

The 2012-2013 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, Western Electricity Coordinating Council (WECC) regional criteria, and ISO planning standards across the 2013-2022 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2012-2013 study.

2.2.1 NERC Reliability Standards

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

The ISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following TPL NERC reliability standards are applicable to the ISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:

- 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).

2.2.2 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.[9]

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.[10] 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.

2.3 Study Methodology and Assumptions

The following sections summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Methodology

As noted earlier, the backbone and regional planning region assessments 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 regional planning 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

[9] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[10] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

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. An example of such a power generating facility is the Delta Energy Center, which is composed of three combustion turbines and a single steam turbine.

2.3.1.3 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.

Table 2.3-1: WECC transient stability criteria[11]

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 2012-2013 transmission planning analysis.

2.3.2.1 Study Horizon and Study Years

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

The studies that comply with TPL-001, TPL-002, and TPL-003 were conducted for the near-term (2013-2017) and longer-term (2018-2022) periods as per the requirements of the reliability standards. According to the requirements under the TPL-004 standard, the studies that comply with the extreme events criteria were only conducted for the short-term scenarios (2013 -2017).

Within the near- and longer-term study horizon, the ISO conducted detailed analysis on 2014, 2017 and 2022. Some additional years were identified as required for assessment in specific planning regions.

2.3.2.2 Peak Demand

The ISO-controlled grid peak demand in 2012 was 46,810 MW and occurred on August 13, 2012 at 3:54 p.m. SCE and PG&E peak demands occurred on the same date as the ISO but at different times: The SCE peak occurred on August 13, 2012, at 2:55 p.m. with 22,498 MW and for PG&E, it occurred on August 13, 2012, at 4:51 p.m. with 20,272 MW. Meanwhile, the peak demand for SDG&E occurred on September 14, 2012 at 4:00 p.m. with 4,636 MW.

Most of the ISO-controlled grid experiences summer peaking conditions and thus was 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 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	2014	2017	2022
Northern California (PG&E) Bulk System*	Summer Peak Summer Light Load	Summer Peak Summer Partial Peak Summer Off-Peak	Summer Peak Summer Light Load
Humboldt	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Summer Light Load	Summer Peak Winter peak Summer Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak (SF & Peninsula) Summer Light Load	Summer Peak Winter peak (SF & Peninsula) Summer Off-Peak	Summer Peak Winter peak (SF Only)
San Joaquin Valley (Yosemite, Fresno, Kern)	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak Summer Partial Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak
Consolidated Southern California	Summer Peak Summer Light Load	Summer Peak Spring Off-Peak	Summer Peak Summer Light Load
Southern California Edison (SCE) area	Summer Peak Summer Light Load	Summer Peak Spring Off-Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak

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 2012-2013 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.

Loss of a single bulk electric system element (BES) (TPL-002 - Category B)

The assessment considers all possible Category B contingencies based upon the following:

- loss of one generator (B1);
- loss of one transformer (B2);
- loss of one transmission line (B3);
- loss of a single pole of DC lines (B4);
- loss of the selected one generator and one transmission line (G-1/L-1), where G-1 represents the most critical generating outage for the evaluated area; and
- loss of both poles of a Pacific DC Intertie.

Loss of two or more BES elements (TPL-003 - Category C)

The assessment considers the Category C contingencies with the loss of two or more BES elements which produce the more severe system results or impacts based on the following:

- breaker and bus section outages (C1 and C2);
- combination of two element outages with system adjustment after the first outage (C3);
- loss of both poles of DC lines (C4);
- all double circuit tower line outages (C5);
- stuck breaker with a Category B outage (C6 thru C9); and
- loss of two adjacent transmission circuits on separate towers.

Extreme contingencies (TPL-004 - Category D)

The assessment considers the Category D contingencies of extreme events which produce the more severe system results or impact as a minimum based on the following:

- loss of 2 nuclear units;
- loss of all generating units at a station;
- loss of all transmission lines on a common right-of-way;
- loss of substation (One voltage level plus transformers); and
- certain combinations of one element out followed by double circuit tower line outages.

2.3.2.5 Generation Projects

The ISO modeled approximately a 20 percent renewable energy scenario for the 2017 reliability study case. This included the renewable generation and associated transmission in the ISO queue that was expected to be in service by 2016:

For the 2022 reliability study cases, the ISO modeled the base 33 percent RPS portfolio from chapter 4 of the 2011-2012 Transmission Plan. However, in some areas where renewable generation modeling was substantial, some sensitivity studies were performed without any expected renewable generation modeled. These studies were performed to address the possibility that the modeled renewable generation would not actually be built or would not be operating because of 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 established 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 existing non-nuclear fossil fuel power plants using once-through cooling to submit an implementation plan to the SWRCB on April 1, 2011. In most cases, the plans selected an alternative that would achieve compliance, contingent on future commercial arrangements, by a date specified for each facility identified in the policy.

In the 2011-2012 Transmission Plan, the ISO performed an analysis of the potential reliability impacts associated with the potential retirement of OTC generation, and identified the minimum amount of OTC generation that would need to be replaced. The ISO modeled this minimum amount of OTC generation in the reliability models. Because of the uncertainty regarding future commercial arrangements associated with implementation plans, the OTC replacement generation modeled was intended to be a proxy for an electrically equivalent amount of generation that is needed. Many 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 in service and the expected future 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 related transmission 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 participating transmission owners using the revised mid-case California Energy Demand Forecast 2012-2022 released by California Energy Commission (CEC) dated February 2012 as the starting point because the CEC forecast did not provide bus-level demand projections. The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the backbone system assessments 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 and Off-peak Conditions

The assessment evaluated the light load and off-peak conditions in all study areas 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 represented the system minimum load conditions while the off-peak load conditions ranged from 50 percent to 70 percent of the peak load in that area, such as weekends. Critical system conditions in specific study areas can occur during partial peak periods because of loading, generation dispatch and facility rating status and were studied accordingly.

2.3.2.8 Reactive Power Resources

Existing and new reactive power resources were modeled in the study base cases to ensure realistic reactive power support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. 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 the following:

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

For a complete resources list, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[12]

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.

[12] 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
7570	South of Lugo 500 kV lines
6110	COI Master Operating Procedure
7430	Fresno Area Operating Procedures
6310	Path 15 (Midway-Los Banos) Operating Procedure
6410	Path 26 – Midway-Vincent Operating Procedure
6510	Southern California Import Transmission (SCIT)

2.3.2.10 Firm Transfers

Power flow into and within the ISO BAA on the major power transmission paths was considered and modeled as firm transfers. In general, the northern California system has two major power transfer paths (i.e., Path 66 and Path 26). Table 2.3-4 lists the power transfers that were modeled in each scenario on these paths in the northern area assessment for the 2017 and 2022 base cases. Negative flow in the table indicates a reversal of flow direction than indicated for the path. The table also shows dispatch of the hydro power plants in Northern California in the peak load cases as percentage of these plants capability.

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

Import Path	2017 Summer Peak	2017 Summer Off-Peak	2022 Summer Peak	Transfer Capability
California-Oregon Intertie Flow (N-S) (MW)	4,800	-2,477	4,800	4,800/-3,675
Pacific DC Intertie Flow (N-S) (MW)	3,100	2,000	3,100	+/-3,100
Path 15 Flow (N-S) MW	1,700	-5,180	-695	-5,400
Path 26 Flow (N-S) MW	4,000	-1,777	1,700	4,000/-3,000
Northern California Hydro % dispatch of nameplate	80%	N/A	80%	N/A

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

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

Import Path	2017 Summer Peak	2017 Spring Off-Peak	2022 Summer Peak
Path 26 Flow (N-S) (MW)	2,846	1,656	2,635
West of River (E-W) (MW)	7,031	5,818	7,963
East of River (E-W) (MW)	4,794	3,285	4,256
Pacific DC Intertie Flow (N-S) (MW)	3,098	1,500	3,100

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

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

Import Path	Path Flow (MW)	
	2017 Summer Peak	2022 Summer Peak
Northern-Southern California (Path 26)	2,713	2,277
PDCI	2,800	1,474
IID-SCE	409	410
North of San Onofre	1,329	1,111
South of San Onofre	821	1,039
ISO-Mexico (CFE)	-1	0.3
West of Colorado River (WOR)	6,208	6,721
East of Colorado River (EOR)	3,910	3,756
Lugo-Victorville 500 kV line	1,375	1,393

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. The SPS on the system are listed in Appendix A.

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 Intertie (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, 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

The figure below provides a simplified map of the PG&E bulk transmission system.

Figure 2.4-1: 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 accessing 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. The typical direction of power flow through Path 15 (Los Banos Gates #1 and #3 500 kV lines and Los Banos-Midway #2 500 kV line) is from south to north during off-peak load periods. The typical direction of power flow through California-Oregon Intertie (COI, Path 66) and through the Pacific DC Intertie (Bi-pole DC transmission line connecting the Celilo Substation in Washington State with the Sylmar Substation in Southern California) is from north to south during summer on-peak load periods and in the reverse direction during off-peak load periods in California or Winter Peak periods in Pacific Northwest.

Because of this bi-directional power flow pattern on the 500 kV Path 26 lines and on COI, both the Summer Peak (N-S) and off-peak (S-N) flow scenarios were analyzed, as well as a partial peak scenario. Transient stability and post transient contingency analyses were also performed for all 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 section 2.3.2. 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 2014, 2017 and 2022, Summer Off-Peak and partial peak cases for 2017 and light load cases for 2014 and 2022. 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. In addition, such extreme events as contingencies that involve a loss of major substations and all transmission lines in the same corridors were studied.

Generation and Path Flows

The bulk transmission system studies use the same set of generation plants that are 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 2022 in addition to the conventional study that models new generators according to the ISO guidelines for modeling new generation interconnection projects. Therefore, an additional amount of renewable resources was modeled in the 2017 and 2022 base cases according to the information in the ISO large generation interconnection queue. Only those resources that are proposed to be on line in 2017 or prior to 2017 were modeled in the 2017 cases. 2014 cases modeled new generation projects that are expected to be in service in 2014 or prior to 2014. A summary of generation is provided in each of the local planning areas within the PG&E area.

Because 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 paths' flow limits, or as high as the generation resource assumptions allowed. Table 2.4-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4-1: Major import flows for the northern area bulk study

Parameter	2014 Summer Peak	2014 Summer Light Load	2017 Summer Peak	2017 Summer Partial Peak	2017 Summer Off-Peak	2022 Summer Peak	2022 Summer Light Load
California-Oregon Intertie Flow (N-S) (MW)	4,800	1,056	4,800	4,690	-2,477	4,800	-354
Pacific DC Intertie Flow (N-S) (MW)	3,100	500	3,100	2,700	-2,000	3,100	0
Path 15 Flow (S-N) (MW)	-1,607	64	-1,700	-2,575	5,180	695	-718
Path 26 Flow (N-S) (MW)	4,000	1,242	4,000	3,935	-1,777	1,700	1,683
Northern California Hydro % dispatch of nameplate	80%	39%	80%	80%	45%	80%	45%

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. The light load cases modeled the lowest load in the PG&E area that appears to be lower than the off-peak load. Table 2.4-2 shows the assumed load levels for selected areas under Summer Peak and off-peak conditions.

Table 2.4-2: Load modeled in the PG&E bulk transmission system assessment

Scenario	Area	Load (MW)	Loss (MW)	Total (MW)
2014 Summer Peak	PG&E	27,970	1,083	29,053
	SDG&E	5,301	137	5,438
	SCE	26,223	451	26,674
	ISO	59,494	1,671	61,165
2014 Summer Light Load	PG&E	11,184	316	11,500
	SDG&E	4,042	88	4,130
	SCE	14,427	171	14,598
	ISO	29,653	575	30,228
2017 Summer Peak	PG&E	29,054	1,094	30,148
	SDG&E	5,356	114	5,470
	SCE	27,362	484	27,846
	ISO	61,772	1,692	63,464
2017 Summer Partial Peak	PG&E	26,054	1,103	27,157
	SDG&E	5,302	112	5,414
	SCE	27,088	483	27,571
	ISO	58,444	1,698	60,142
2017 Summer Off-Peak	PG&E	14,096	593	14,689
	SDG&E	3,982	62	4,044
	SCE	17,197	291	17,488
	ISO	35,275	946	36,221
2022 Summer Peak	PG&E	30,703	1,117	31,820
	SDG&E	5,628	121	5,749
	SCE	28,227	474	28,701
	ISO	64,558	1,712	66,270
2022 Summer Light Load	PG&E	12,349	328	12,677
	SDG&E	4,249	102	4,351
	SCE	21,941	381	22,322
	ISO	38,539	811	39,350

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 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study assessment of the northern bulk system yielded the following conclusions:

- two overloads are expected under partial peak summer conditions in 2017 with all facilities in service and with single or multiple contingencies.
- two overloads are expected under peak load conditions with Category B contingencies with the potential for additional facility to overload under partial peak. These overloads may be mitigated by congestion management and phase shifter adjustments.
- one Category B overload is expected under off-peak conditions that can be mitigated by applying short-term emergency rating.
- there are two approved transmission projects that will mitigate three Category C overloads that may occur under peak load conditions. Prior to the approved upgrades being completed, congestion management, SPS to reduce generation and SPS to perform switching actions will be used.
- in addition to the facilities that may overload under Category A and B conditions, and the facilities that will be upgraded with the approved transmission projects, there were three overloads expected under peak and partial peak conditions and two overloads expected under off-peak conditions with Category C contingencies.

The ISO-proposed solution to mitigate the identified reliability concerns are as follows:

- modify the 500 kV Double Outage South of Table Mountain RAS;
- adjust the Weed Junction phase shifter taps or obtain short term emergency ratings for the Crag View- Weed Junction and Delta-Cascade 115 kV lines;
- use congestion management to reduce generation from Contra Costa to mitigate overloads on the Lone Tree-Cayetano 230 kV, and Contra Costa- Contra Costa Substation 230 kV lines;
- modify Ashland 230 kV SPS; and
- use short-term emergency rating for emergency overload on the Midway-Gates 230 kV line.

Overloads of the Warnerville-Wilson 230 kV, Bellota-Warnerville 230 kV, Westley-Los Banos 230 kV transmission lines and Gates 500/230 kV transformer are being addressed in the

Central California Study. The outages that may cause these overloads and mitigation plans are discussed in section 3.2 of the plan.

The ISO will also work with PG&E on mitigation of the concerns identified in the transient stability studies within Appendix B. The solution may be developing an SPS to trip some of the Wind Gap pumping load or upgrade of the current protection relays, or installation of dynamic reactive support in this area.

The ISO has received a project proposal for the PG&E Bulk Transmission System in the 2012 Request Window – Midway Long Term Area Study. This project was submitted as a conceptual plan requiring further evaluation. The purpose of the Midway Long Term Area Study is to protect against Category D contingencies in the Midway area. The ISO will work with PG&E on this project.

2.5 PG&E Local Areas Assessment

In addition to the PG&E bulk area study, studies were performed for its eight local areas.

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 2012-2013 transmission planning studies, a Summer Peak and Winter Peak assessment was performed. Additionally a Summer Light Load condition for 2014 and a Summer Off-Peak condition for 2017 assessments were also performed. For the Summer Peak assessment, a simultaneous area load of 168 MW in the 2017 and 184 MW in the 2022 time frames were assumed. For the Winter Peak assessment, a simultaneous area load of 196 MW and 211 MW in the 2017 and 2022 time frames were assumed. An annual load growth of about 4 MW per year for summer and 3 MW per year for Winter Peak 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. Summer Peak and Winter Peak assessment were done for the study years 2014, 2017 and 2022. Additionally a 2014 Summer Light Load condition and a 2017 Summer Off-Peak condition were also studied.

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. This facility 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 lists a summary of the generation in the Humboldt area, with detailed generation listed in Appendix A.

Table 2.5-1: Humboldt area generation summary

Generation	Capacity (MW)
Thermal	191
Hydro	5
Biomass	62
Total	**258**

Load Forecast

Loads within the Humboldt area reflect a coincident peak load for 1-in-10-year heat wave conditions of each study year. Table 2.5-2 and Table 2.5-3 summarize loads modeled in the studies for the Humboldt area.

Table 2.5-2: Load forecasts modeled in Humboldt area assessment, Summer Peak

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		
	2014	2017	2022
Humboldt	**157**	**168**	**184**

Table 2.5-3: Load forecasts modeled in Humboldt area assessment, Winter Peak

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2014	**2017**	**2022**
Humboldt	**187**	**196**	**211**

2.5.1.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study of the Humboldt area yielded the following conclusions:

- one overload would occur under normal conditions in 2014 and 2017 study years for which ISO has an approved transmission project.
- low voltages and large voltage deviations would occur for Category B and Category C contingencies prior to installation of reactive support on the 60 kV substations in the Maple Creek and Garberville areas. The existing PG&E Action Plan will mitigate these voltage concerns as an interim measure until the Maple Creek and Garberville reactive support projects come into service.
- after installation of the Maple Creek and Garberville reactive support, no low voltages are expected.
- voltage and voltage deviation concerns were identified on 60 kV buses in the summer and Winter Peak conditions for various Category B and C contingencies in and around the Blue Lake Power Plant, Arcata, Orick, Big Lagoon and Trinidad substations. PG&E has an action plan to mitigate the voltage concerns in the near team. The Northern Humboldt long term study will identify comprehensive solutions for the long term.
- in addition to the facilities overloaded for Category B contingencies, 10 transmission facilities may become overloaded with various Category C contingencies both in Summer and Winter Peak conditions.

The identified overloads will be addressed as follows:

- for one Category B overload (three sections of the Rio Dell-Bridgeville 60 kV line), it is proposed to install an SPS to trip the generation project that plans to connect to this line with the overload. If the renewable generation project does not proceed to come online, there may be additional issues that may need to be resolved. ISO will work with PG&E to formulate mitigation plans in that scenario.

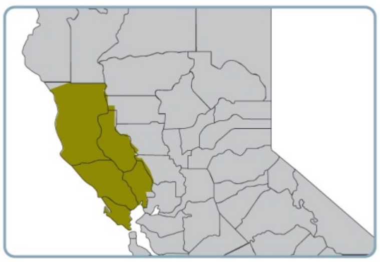
- the overload on the Bridgeville-Garberville 60 kV line that is expected under normal conditions and under multiple Category B & C contingencies starting in 2014 is proposed to be mitigated by a transmission upgrade that would construct a new Bridgeville-Garberville 115 kV transmission line. This upgrade will also solve voltage concerns in the Bridgeville area. This new 115kV transmission line project was already approved by the ISO in the 2011-2012 transmission plan.
- the low voltages and voltage deviation concerns in the most northern part of Humboldt County are proposed to be mitigated by using PG&E action plans in the interim. The Northern Humboldt area study will come up with comprehensive solutions to mitigate the issues in the long term.

The ISO did not receive any capital projects for approval in this year in the Humboldt area. The Northern Humboldt Long Term Study was submitted as a conceptual project for the Humboldt area.

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 816 MW in 2017 and 901 MW in 2022 time frames was assumed. For the Winter Peak assessment, a simultaneous area load of 714 MW and 789 MW in the 2017 and 2022 time frames was assumed. An annual load growth for Summer Peak of approximately 14 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 to the East Bay by 230 kV lines between Lakeville and Vaca Dixon.

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 788 MW and 821 MW in the 2017 and 2022 time frames was assumed. For the Winter Peak assessment, a simultaneous area load of 778 MW and 810 MW in the 2017 and 2022 time frames was assumed. An annual load growth for Summer Peak of approximately 11 MW and for Winter Peak of approximately 11 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. Summer Peak and Winter Peak assessments were done for North Coast and North Bay areas for the study years 2014, 2017 and 2022. Additionally a 2014 Summer Light Load condition and a 2017 Summer Off-Peak condition were studied for both North Coast and North Bay areas.

Generation

Generation resources in the North Coast and North Bay areas consist of market, qualifying facilities and self-generating units. Table 2.5-4 lists a summary of the generation in the North Coast and North Bay area, with detailed generation listed in Appendix A.

Table 2.5-4: North Coast and North Bay area generation summary

Generation	Capacity (MW)
Thermal	54
Hydro	26
Geo Thermal	1,533
Biomass	6
Total	**1,619**

The studies also modeled two future renewable generation projects. A new 10 MW biomass generation project was assumed to be 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.

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.

Table 2.5-5 and Table 2.5-6 summarize the substation loads assumed in the studies for North Coast and North Bay areas under summer and Winter Peak conditions.

Table 2.5-5: Load forecasts modeled in North Coast and North Bay area assessments, Summer Peak

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2014	**2017**	**2022**
North Coast	774	816	901
North Bay	753	788	821

Table 2.5-6: Load forecasts modeled in North Coast and North Bay area assessments, Winter Peak

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	**Winter Peak (MW)**		
	2014	**2017**	**2022**
North Coast	677	714	789
North Bay	743	778	810

2.5.2.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. 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), which was also discussed in the Humboldt section of this report. This overload will be mitigated by the previously approved new Bridgeville – Garberville 115kV line.
- overall there were seven Category B and 39 Category C overloads identified in this year's assessment
- low voltage violations have been found for four Category B conditions and 45 different Category C conditions.
- voltage deviation concerns were identified for 27 Category B conditions and 12 Category C conditions.

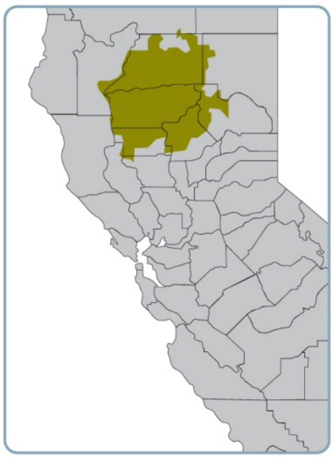
The ISO received one proposed transmission project through the 2012 Request Window. The project need was primarily been driven by the reliability needs on the PG&E's distribution system and there were no transmission concerns identified in this year's assessment that would need this project in service. On reviewing the distribution needs presented by PG&E, ISO concurred with the new Windsor substation project. The other projects in the North Coast/North Bay area submitted by PG&E were conceptual in nature and are not being recommended for approval by the ISO. This year's analysis shows that the previously approved projects in the North Coast/North Bay area 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.

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 1,008 MW by 2022, 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 2.5.3-2 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 Market Participant Portal lists the 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 located in this area. These facilities are fed from the following river systems: Pit River, Battle Creek, 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 natural gas-fired 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. Table 2.5-7 lists a summary of the generation in the North Valley area, with detailed generation listed in Appendix A.

Table 2.5-7: North Valley area generation summary

Generation	Capacity (MW)
Thermal	1,070
Hydro	1,670
Wind	103
Total	**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 2.5-8 shows loads modeled for the North Valley area assessment.

Table 2.5-8: 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)		
	2014	2017	2022
North Valley	916	956	1,008

2.5.3.3 Assessment and Recommendations

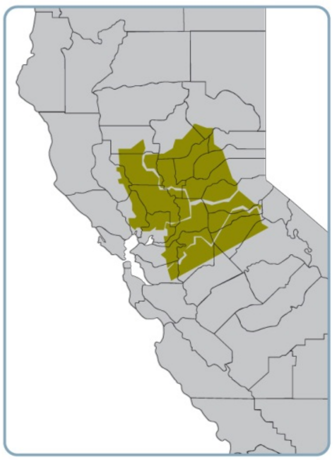
The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2012 reliability assessment of the PG&E North Valley area identified several reliability concerns. These concerns consist of thermal overloads and low voltages under 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 division 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 division 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 division 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 division 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 4,536 MW by 2022 assuming load is increasing by approximately 62 MW per year.

Accordingly, system assessments in these areas included technical studies using load assumptions for these Summer Peak conditions. Table 2.5-10 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. The total installed capacity is approximately 3,459 MW with another 530 MW of North Valley generation being connected directly to the Sierra division. Table 2.5-9 lists a summary of the generation in the Central Valley area, with detailed generation listed in Appendix A.

Table 2.5-9: Central Valley area generation summary

Generation	Capacity (MW)
Thermal	1,359
Hydro	1,545
Wind	894
Biomass	162
Total	**3,960**

- Sacramento division — there is approximately 970 MW of internal generating capacity within the Sacramento division. More than 800 MW of the capacity (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.
- Sierra division — there is approximately 1,250 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.
- Stockton division — there is approximately 1,370 MW of internal generating capacity in the Stockton division.
- Stanislaus division — there is approximately 590 MW of internal generating capacity in the Stanislaus division. More than 90 percent of this generating capacity is from hydro

resources. The remaining capacity consists of QFs and co-generation plants. The 333 MW Melones power plant is the largest generating facility in the area.

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 2.5-10 shows loads modeled for the Central Valley area assessment.

Table 2.5-10: 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)**		
	2014	**2017**	**2022**
Sacramento	1,164	1,211	1,284
Sierra	1,269	1,340	1,454
Stockton	1,369	1,435	1,527
Stanislaus	241	252	270
TOTAL	**4,035**	**4,238**	**4,536**

2.5.4.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2012 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 reliability issues identified in this assessment are very similar to those found in last year's assessment. One project that was approved last year eliminated low voltages under normal system conditions at eight substations. To address the additional identified thermal overloads and low voltage concerns in this year's assessment, the ISO recommends the following transmission development projects in the area as a part of the mitigation plan.

Pease 115/60 kV Transformer Addition and Bus Upgrade

The project scope includes the following:

- add a new 115/60 kV transformer rated at 200 MVA at Pease Substation;
- reconfiguring the Pease 115 kV Bus to breaker-and-a-half;
- replacing any limiting equipment on the existing Pease 115/60 kV transformer in order to achieve the transformer's normal and emergency ratings; and
- install a UVLS to drop load at Harter Substation when detecting low voltages there, which should be completed as an interim solution until the new Pease 115/60 kV Transformer is installed.

This project addresses all reliability issues identified in the Pease 60 kV system. The ISO determined that the Pease 115/60 kV Transformer Addition and Bus Upgrade project as needed to address thermal overloads and voltage concerns in the Pease 60 kV system. This project also provides adequate outlet for generation connected to the Pease 60 kV system during low load conditions. The project is expected to cost $25 million to $35 million and has an in-service date of May 2016. Operating action plans are in place to address these reliability concerns in the interim.

Atlantic-Placer 115 kV Line

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

- Placer 115/60 kV Transformer #1 overload (starting in 2020 under Category A);
- Drum-Higgins 115 kV line overload (starting in 2021 under Category A and existing under Category C);
- Drum-Rio Oso 115 kV Line #1 (existing overload under Category C);
- Drum-Rio Oso 115 kV Line #2 (existing overload under Category C);
- Drum-Grass Valley-Weimar 60 kV Line (existing overload under Category B);
- Gold Hill 230/115 kV Transformer #1 (starting in 2021 under Category B and existing overload under Category C);
- Gold Hill 230/115 kV Transformer #2 (starting in 2021 under Category B and 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 (existing and potential voltage collapse under Category C); and
- Gold Hill Area Voltages (existing and potential voltage collapse under Category C);

To mitigate these overloads and voltage issues, PG&E submitted a project through the 2012 Request Window — the *Placer 115/60 kV Transformer Replacement and SPS Project*. This project proposes to replace the existing 115/60 kV transformer at Placer with a new 200 MVA transformer and install a SPS to drop load in Placer area following the Gold Hill-Placer 115 kV double circuit tower line outage. The project, as proposed, does not address all of the reliability concerns identified in the area. To address the reliability concerns in the area holistically, the ISO proposed a different alternative that includes building a new 115 kV line between existing Atlantic and Placer 115 kV substations (approximately 14 miles long), adding a second Placer 115/60 kV transformer and installing an SPS for loss of two Gold Hill 230/115 kV transformers. This alternative addresses all reliability issues identified in the Gold Hill and Placer areas as well as the normal overload on the Drum-Higgins 115 kV line. Other overloads on Drum 115 kV system are expected to be mitigated through the existing ISO Operating Procedure 7240. With this the ISO determined that the Atlantic-Placer 115 kV Line project as needed to address thermal overloads and voltage concerns in the Gold Hill, Placer and Drum 115 kV system. The project is expected to cost $55 million to $85 million. Because of permitting and lead times, the most feasible project implementation date is 2017. Operating action plans are in place to address these reliability concerns in the interim.

Ripon 115 kV Line

PG&E submitted this project through the 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0). The project scope of work includes following:

- constructing a second 115 kV tap line (5 miles long) from Riverbank Junction Switching Station - Manteca 115 kV Line to Ripon Substation, which will be sized to handle at least 440 Amps and 514 Amps under normal and emergency conditions, respectively; and
- installing two line circuit breakers to create a loop into Ripon Substation.

Ripon Substation serves over 5,500 electric customers (22 MW), via a radial 4.6-mile long connection (Ripon 115 kV Tap) off the Riverbank Junction Switching Station – Manteca 115 kV Line. Currently an outage of the Riverbank Junction Switching Station – Manteca 115 kV line will result in the loss of electric service to Ripon customers. The River Bank Junction Switching Station – Manteca 115 kV has an average of 2.2 outages per year, due mostly to weather, animal and vehicle contact. The average for the Stockton area is 1.6 outages per year. To increase reliability performance for the electric customers served by Ripon Substation, PG&E submitted this project through the 2012 Request Window to create a second source to Ripon Substation. The ISO determined that the Ripon 115 kV Line project as needed based on the BCR of 3.66 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $10 million to $15 million and has an in-service date of May 2015.

Salado 115/60 kV Transformer Addition

PG&E submitted this project through the 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope is to install a new 115/60 kV transformer, upgrade the existing 115 kV loop bus to a two-bay breaker-and-a-half bus at Salado Substation, and install a MPAC building at Salado Substation.

Salado substation serves approximately 8,600 customers (16 MVA) via the local 60 kV transmission system via one 115/60 kV transformer. Currently an outage of Salado 115/60 kV Transformer #1 will result in a sustained outage to all of the 60 kV electric customers served by this substation. This outage can add at least 12.3 million customer outage minutes assuming the outage lasts up to 24 hours following the loss of one of the phases. This outage can be longer depending upon the availability and location of a spare or mobile transformer. PG&E has identified the need to replace this 58 year-old transformer in 2014, as part of the maintenance program because of its deteriorated condition. Furthermore, performing maintenance on this transformer is very challenging because it has weak back ties to the neighboring transmission system. The current 115 kV loop arrangement does not allow for addition of another element. A loop arrangement could result in an outage of the entire substation following a bus fault or circuit breaker failure. To increase reliability performance for the electric customers served by Salado substation, PG&E submitted this project through the 2012 Request Window to install a second 115/60 kV transformer and convert 115 kV bus to a breaker-and-a-half. The ISO determined that the Salado 115/60 kV Transformer Addition project as needed based on a benefit-cost ratio of 1.12 per ISO Grid Planning Standards, Section VI - 4. The project is expected to cost $15 million to $20 million and has an in-service date of December 2014.

Lockeford-Lodi Area 230 kV Development

This year's assessment identified the following facilities in the Lockeford/Lodi 60kV system as not meeting the thermal and voltage performance requirements:

- Lockeford-Industrial 60 kV line overload (existing overload under Category C)
- Lockeford-Lodi 60 kV line #1 overload (existing overload under Category C)
- Lockeford-Lodi 60 kV line #2 overload (existing overload under Category C)
- Lockeford-Lodi 60 kV line #3 overload (existing overload under Category C)
- Lodi-industrial 60 kV line overload (existing overload under Category C)
- Lodi Area Voltages (existing high voltage deviation under Category B & C)

To mitigate the overloads and voltage issues, City of Lodi submitted a project through the 2012 Request Window — the *PG&E Lockeford-Lodi Area Study: Alternative 2*. The submission was an alternative to be considered in developing the mitigation plan for the reliability issues in Lodi 60 kV system. The project scope includes the following:

- construct a 230 kV Double Circuit Transmission Line from Eight Miles substation to Lockeford substation;
- construct a new 230 kV bus at Industrial substation and loop one of the new Eight Miles-Lockeford 230 kV lines into this bus.

This project addresses all reliability issues identified in the Lockeford/Lodi 60 kV system. The ISO determined that the new Eight Mile-Lockeford 230 kV double circuit tower line project as needed to address thermal overloads and voltage concerns in the Lockeford/Lodi 60 kV system. The project is expected to cost $80M to $105M. Because of permitting and lead times, the most feasible project implementation date is 2017. Operating action plans are in place to address these reliability concerns in the interim.

Kasson SPS Project

In addition to the projects identified above as recommended for approval, the ISO concurs with the SPS project submitted by PG&E as a part of the mitigation plan for the area.

The ISO identified existing overloads on the Kasson-Louise, Manteca-Louise 60 kV lines and Manteca 115/60 kV Transformer #3 under a Category C contingency condition. To mitigate these overloads, PG&E submitted a project through the 2012 Request Window — *Kasson SPS Project*. The project scope is to install a SPS to trip Kasson Circuit Breakers 12, 22, 32, and 42 following a Kasson 115 kV Bus outage. The project is expected to cost $1 million to $3 million and has an in-service date of May 2015 or earlier. Operating action plans are in place to address these reliability concerns in the interim. The ISO reviewed and concurred with the proposed SPS to mitigate the identified thermal overloads.

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. To better conduct the performance evaluation, the 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 encompasses San Francisco and San Mateo Counties, which include 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.

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 participant portal 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 2.5-11 lists a summary of the generation in the Greater Bay area, with detailed generation listed in Appendix A.

Table 2.5-11: Greater Bay area generation summary

Generation	**Capacity (MW)**
Thermal	8,097
Wind	162
Biomass	13
Total	**8,272**

Load Forecast

Loads within the Greater Bay Area reflect a coincident peak load for 1-in-10-year heat wave conditions. Table 2.5-12 and Table 2.5-13 show the area load levels modeled for each of the PG&E local area studies, including the Greater Bay Area.

Table 2.5-12: Summer Peak load forecasts for Greater Bay Area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area	Summer Peak (MW)		
	2014	2017	2022
East Bay	983	1,011	1,060
Diablo	1,639	1,675	1,734
San Francisco	973	1,003	1,049
Peninsula	1,004	1,040	1,098
Mission	1,330	1,371	1,454
De Anza	989	1,026	1,076
San Jose	1,868	1,953	2,058
TOTAL	**8,786**	**9,079**	**9,529**

Table 2.5-13: Winter Peak load forecasts for San Francisco and Peninsula Area assessments

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area	Winter Peak (MW)		
	2014	2017	2022
San Francisco	930	960	1,005
Peninsula	968	1,003	1,060

2.5.5.3 Assessment and Recommendations

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2012 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. To address the identified thermal overloads and low voltage concerns, the ISO recommends the following of transmission development projects in the area as a part of the mitigation plan.

Contra Costa Sub Switch Replacement

The project is to replace Contra Costa Sub 230 kV Switch No. 237 and any other associated limiting equipment. This project will increase the Contra Costa PP-Contra Costa Sub 230 kV Line summer emergency rating to 1893A (from 1600A). The project is expected to cost less than $1 million with an expectation to be in service by 2015.

This project is recommended to address the Contra Costa PP - Contra Costa Sub 230 kV Line overload caused by the Category B outage of Birds Landing-Contra Costa PP 230kV and Gateway generator offline at the expected load level of summer 2013. In the interim, the ISO will rely on reducing local generation through the existing ISO market mechanism to avoid this overload.

Los Esteros-Montague 115 kV Substation Equipment Upgrade

The project is to upgrade limiting substation equipment at Montague Substation to fully utilize the Los Esteros-Montague 115 kV Line. The project is expected to cost $0.5 million to $1 million with an expectation to be in service by 2016.

This project is recommended to address the Los Esteros-Montague 115 kV Line overload caused by the Category B outage of the Los Esteros-Trimble 115 kV Line at the expected load level of summer 2019.

Monta Vista-Wolfe 115 kV Substation Equipment Upgrade

The project is to upgrade limiting substation equipment at Wolfe Substation to fully utilize the Monta Vista-Wolfe 115 kV Lines installed conductor capacity. The project is expected to cost $0.5 million to $1 million with an expectation to be in service by 2015.

This project is recommended to address the Monta Vista-Wolfe 115 kV Line overload caused by the Category B outage of the Stelling-Monta Vista 115 kV Line at the expected load level of summer 2015.

Monte Vista 230 kV Bus Upgrade

The project is to upgrade the configuration of the Monta Vista 230 kV Bus with bus sectionalizing breakers. The project is expected to cost $10 to $15 million with an expectation to be in service by 2016.

The Category C contingency of the stuck breaker in Monta Vista 230 kV substation results in voltage drop and thermal overload in the De Anza Division. The Monte Vista 230kV Bus Upgrade project is to install two bus tie breakers and one bus sectionalizing breaker in the Monta Vista 230 kV substation. The project is recommended to mitigate the Category C contingency by maintaining two of the four Metcalf-Monta Vista 230 kV Lines in service.

NRS - Scott No. 1 115 kV Line Reconductor

The project is to reconductor the NRS-Scott No.1 115 kV Line with conductor which has a summer emergency rating of at least 1500 amps. The project is expected to cost $2 million to $4 million with an expectation to be in service by 2016.

This project is recommended to address the NRS - Scott No.1 115 kV Line overload caused by the Category B outage of either Los Esteros-Nortech 115 kV Line combined with the Silicon Valley Power DVR Power Plant (DVR PP) Generator, the Nortech - NRS 115 kV Line combined with the PVR PP Generator or the NRS - Scott No.2 115 kV Line combined with the DVR PP Generator at the expected load level of summer 2016.

Potrero 115 kV Bus Upgrade

The project scope is to upgrade the Potrero 115 kV bus by removing the tie-lines to the retired Potrero Power Plant, relocating two elements, and adding two sectionalizing breakers. The project is expected to cost $10 million to $15 million with an expectation to be in service by 2017.

Potrero Substation is located in The City of San Francisco and serves roughly 130 MW of demand. The distribution transformers serve approximately 34,000 customers and are all connected to Potrero 115 kV Bus Section D. The substation serves as an import location for the DC Trans Bay Cable (TBC) and the future Potrero-Embarcadero (AZ) 230 kV Line. Potrero exports power to Mission and Larkin Substations via three 115 kV cables, Potrero-Mission (AX) and Potrero-Larkin Nos. 1&2 (AY-1, AY-2). On February 28, 2011 the Potrero Power Plant (Units 3, 4, 5, and 6) was retired from operation.

Planning analysis indicates that a C2 breaker failure of Potrero 115 kV circuit breaker 102 could result in a 156 percent overload on the Potrero-Larkin No. 2 (AY-2) 115 kV Line in 2013. Analysis also indicates that a C1 bus fault on Potrero 115 kV Bus 1D or 2D could result in a 101 percent overload in 2013 on the Potrero-Larkin No. 2 (AY-2) or Potrero-Mission (AX) 115 kV Lines, respectively. In addition, in 2017 analysis indicates a fault on Potrero circuit breaker 412 or Potrero 115 kV Bus 2E could result in up to 107 percent overload on the Potrero-Mission (AX) 115 kV Line.

The proposed scope to relocate elements and add sectionalizing breakers on the Potrero 115 kV bus will decrease the amount of elements on Bus D and create a more reliable layout during bus and breaker faults. The project will remove NERC Category C1 and C2 contingency concerns. The bus rearrangement will also place a distribution transformer on a separate bus section so the loss of Potrero 115 kV Bus Section D will not drop all customers served at the substation.

Christie 115/60 kV Transformer No. 2

PG&E submitted this project through the 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope is to install a new 115/60 kV three-phase, 100 MVA Transformer No. 2 at Christie Substation, reconfigure the 115 kV bus to a 2-bay breaker and a half configuration and install a new control building to house all 115/60 kV protection and controls.

Christie Substation is located in Contra Costa County within PG&E's Bay Area Region. Christie is currently a single-bank station serving approximately 15,600 customers with four single-phase 30 MVA, 115/60 kV transformer units. The existing transformer is approximately 60 years old. Christie Transformer No. 1 serves the 60 kV transmission system composed of Franklin, Stauffer and Urich substations, and large load customers Union Chemical and Port Costa Brick. A sustained outage of Christie Transformer No. 1 results in a sustained outage to all of the approximately 15,600 customers served via the local 60 kV transmission system. The total peak demand in 2012 for these customers is approximately 40 MW.

Historical outage data shows that the Christie 115/60 kV Transformer No. 1 has an average of 0.2 outages per year. It is recommended to install a new 3-phase 115/60 kV, 100 MVA Transformer No. 2, at Christie Substation. Upon completion of this project, the customers served by Franklin, Stauffer and Urich substations, and large load customers Union Chemical and Port Costa Brick will no longer experience outages following a loss of Christie Transformer No. 1.

The ISO determined that the Christie 115/60 kV Transformer No. 2 addition project as needed based on a benefit to cost ratio of 1.3 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $12 million to $17 million with an expectation to be in service by 2014.

Almaden 60 kV Shunt Capacitor

PG&E submitted this project through the 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope is to install a new a 20 MVAR Mechanically Switched Shunt Capacitor with automatic voltage regulator at Almaden 60 kV Substation.

Pacific Gas and Electric Company's Almaden Substation serves electric customers within the city of San Jose in the Greater Bay Area. The Evergreen – Almaden and Los Gatos – Almaden 60 kV Lines terminate at Almaden. This substation is currently served from the Evergreen – Almaden 60 kV line while the source from Los Gatos 60 kV line is open-ended. A flip flop scheme is currently installed to automatically close circuit breaker 52 at Los Gatos following an outage of the Evergreen – Almaden 60 kV Line. Almaden Substation has two distribution transformers (Nos. 1 and 3) which serve over 14,000 electric customers. The 2013 projected total peak load for Almaden substation is approximately 40 MW.

This project will mitigate low voltage at Almaden and Los Gatos Substations following an outage of the Evergreen – Almaden 60 kV Line. Planning analysis determined that the outage of Evergreen – Almaden 60 kV Line will cause low voltage of 0.89 per unit in 2022 and that voltage deviation limits will be exceeded. More importantly, if the station automatics are disabled to avoid the low voltage problems, nearly about 13,000 electric customers in the San Jose area will be dropped after a single contingency event. The proposed project will effectively address this concern.

The ISO determined that the Almaden Shunt Capacitor addition project as needed based on a benefit to cost ratio of 2.99 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $5 million to $10 million with an expectation to be in service by 2015.

Stone 115 kV Back-tie Reconductor

PG&E submitted this project through the 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a benefit to cost ratio above 1.0). The project scope is to reconductor the Markham No.1 Tap of the San Jose 'B' – Stone – Evergreen 115 kV Line.

An outage of the Markham No. 2 Tap 115 kV Line would result in a thermal overload of the San Jose 'B' – Stone – Evergreen 115 kV Line when a flip-flop scheme restores load by energizing the normally open back-tie.

Pacific Gas and Electric Company's Stone Substation serves electric customers within the city of San Jose. This substation is currently tapped off the Metcalf – Evergreen 115 kV No. 2 Line with a back-tie to Markham 115 kV Substation. There are elements (Switch No. 139 at Markham Substation and Circuit Breaker No. 172 at Stone) that are operated normally open which isolates the two substations. In 2011, a flip flop scheme was installed to improve the reliability for Stone Substation. Stone Substation has two distribution transformers (Nos. 1 and 2) that serve over 14,000 electric customers.

The 2013 total peak load for Stone substation is projected to be approximately 62 MW. The San Jose 'B' – Stone – Evergreen 115 kV Line consists of 3/0 AAC, 4/0 AAC, 397.5 AAC, 477 ACSS and 1113 AAC conductors. The current emergency ratings of the two overloaded sections are 64 and 74 MVA.

This project will mitigate a thermal overload on the San Jose 'B' – Stone – Evergreen 115 kV Line (between Markham and Stone) following the loss of the Markham No.2 Tap. Planning analysis determined that the outage of Markham No. 2 Tap will cause the San Jose 'B' – Stone – Evergreen 115 kV Line to exceed its emergency thermal rating by 8 percent in 2017.

Disabling the station automatics as a way to permanently address this issue is not acceptable as 14,000 electric customers in the San Jose area will be dropped after a single contingency event. The proposed project will effectively address this concern.

The ISO determined that the Stone 115 kV Back-tie Reconductor project as needed based on the BCR of 3.39 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $3 million to $6 million with an expectation to be in service by 2016.

Lockheed No. 1 115 kV Tap Reconductor

PG&E submitted this project through 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope is to reconductor the 1.7 mile long Lockheed No. 1 115 kV Tap with a conductor which has a summer emergency rating of at least 700 amps.

An outage of the Newark-Applied Materials 115 kV Line would result in a thermal overload of the Lockheed No.1 115 kV Tap when a flip-flop scheme restores load by energizing the normally open back-tie.

Located just east of the NASA Ames Visitor Center in Santa Clara County, the Lockheed 115 kV Area is double-tapped off of the Newark-Applied Materials and Newark-Lawrence 115 kV Lines. These taps, Lockheed 115 kV No.1 and No. 2, then serve Moffett Field Substation and multiple Lockheed stations via additional taps. A flip-flop scheme restores load by energizing the normally open back-tie (by closing circuit breaker 172 at Lockheed 1 substation) between the two 115 kV taps. Following an outage of the Newark-Lawrence 115 kV Line, the flip flop scheme will restore Lockheed #2 and Lockheed #4 substations which will then be fed by Lockheed No. 1 115 kV tap. Lockheed No. 1 Tap currently consists of 397.5-19 All Aluminum Conductor (AAC) which has a summer emergency rating of 554 amps. The amount of industrial and commercial load in the area is expected to increase significantly in future years because of the expansion and construction of new facilities by high tech customers. Upgrades that should be considered in the future include removing the taps in the area or loop these substations into the Newark-Applied Materials and Newark-Lawrence 115 kV Lines into Lockheed substations to increase the reliability in the area.

Planning studies have concluded that an outage of the Newark-Applied Materials 115 kV Line would result in a 1 percent thermal overload of the Lockheed No.1 115 kV Tap in 2017 and 3 percent by 2022

The ISO determined that the Lockheed No. 1 115 kV Tap Reconductor project as needed based on the BCR of 1.79 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $2 million to $3 million with an expectation to be in service by 2016.

Newark-Applied Materials 115 kV Substation Equipment Upgrade Project

The project is to replace limiting substation equipment, jumper conductors and line terminating equipment, at Newark Substation to utilize the installed conductor capacity on the Newark-Applied Materials (From Newark Sub To 7/4) 115 kV Line. Replacing the limiting substation equipment will result in the Newark-Applied Materials (From Newark Sub To 7/4) 115 kV Line having a summer normal/emergency rating of 1144/1144 Amps.

This project is recommended as a Category B outage of the Britton-Monta Vista 115 kV Line results in an overload of the Newark Applied Materials 115 kV Line in 2017. The project is expected to cost $0.5 to $1 million with an expectation to be in service by 2016.

Trans Bay Cable Dead Bus Energization Project

The Category D contingency of the Loss of Martin substation results in loss of service to the load in the City of San Francisco, along with tripping of Trans Bay Cable (TBC) HVDC from Pittsburg to Potrero. The current configuration of the TBC HVDC requires the receiving end of the system at Potrero to be energized and connected to the grid. This project would allow for energization of the TBC HVDC system's Potrero 115 kV bus and to energize the HVDC cable quickly to supply power from Pittsburg to Potrero in order to restore service to a portion of the load in the City of San Francisco. The supply to the City of San Francisco would be limited to the capability of TBC, which is 400 MW, and would not provide complete restoration of supply to the area under such an event.

This project is recommended to enhance the reliability of supply to the City of San Francisco and to utilize the capability of TBC to restore a portion of the load in the area in an extreme event condition. The project is expected to cost $20 to $30 million with an expectation to be in service by 2014.

San Francisco Peninsula Reliability Concerns

The ISO is continuing to assess the reliability need of the San Francisco Peninsula. To further address the reliability concern in supply to the downtown San Francisco area due to an Extreme Event per the Reliability Criteria, the ISO is assessing if modifications to the existing transmission system are required. The ISO will continue to engage stakeholders through the process of assessing the need and risks to the area and the assessment of alternatives along with the potential urgency to address the concerns based upon the identified need assessment. Depending upon the results, this issue may be brought forward for consideration at a future Board of Governors meeting.

City of Palo Alto Supply

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 City of Palo submitted a mitigation plan through the 2012 Request Window indicating their intention to proceed with upgrades to their system to address the identified reliability concerns. The ISO will continue to work with the City of Palo Alto and PG&E to assess any interactions between the City of Palo's electric system and the ISO controlled grid. In addition, the ISO recommends PG&E to install an SPS at Palo Alto substation to address the reliability constraints in the interim.

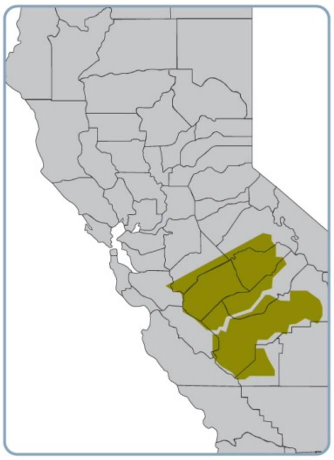
Amazon A100 Data Center

In addition to the projects identified above as recommended for approval, the ISO concurs with the load addition project submitted by PG&E to facilitate the interconnection of the customer owned 115 kV substation to PG&E's East shore 115 kV substation.

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 lines 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 12 transmission circuits. These consist of nine 230 kV lines; two 500/230 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 Pump Storage Power Plant during off-peak conditions. Load forecasts indicate the Greater Fresno area should reach its Summer Peak demand of approximately 3,760 MW assuming load is increasing at a rate of 45 MW per year. This area has a maximum capacity of about 4,150 MW of local generation in the 2022 case. 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 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 2.5-14 lists a summary of the generation in the Greater Fresno area, with detailed generation listed in Appendix A.

Table 2.5-14: Greater Fresno area generation summary

Generation	Capacity (MW)
Thermal	1,312
Hydro	2,059
Solar	40
Biomass	150
Total	**3,561**

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 2.5-15 shows the substation loads assumed in these studies under Summer Peak conditions.

Table 2.5-15: Load forecasts modeled in Fresno and Yosemite area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		
	2014	2017	2022
Yosemite	693	709	736
Fresno	2,222	2,319	2,507

2.5.6.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.3. Details of the planning assessment results are presented in Appendix B. The ISO study of the Fresno area yielded the following conclusions:

- one overload would occur under normal conditions for Summer Peak.
- one overload would be caused by critical single contingencies under Summer Peak conditions.
- multiple 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 10 project proposals from PG&E through the 2012 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.

To address the identified thermal overloads and low voltage concerns in the area, the ISO recommends the following transmission development projects as a part of the mitigation plan.

Arco #2 230/70kV transformer

PG&E submitted this project through 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope includes the following:

- install three new single-phase, 230/70 kV, 60 MVA transformers and a 180 MVA, 70 kV voltage regulator at Arco Substation;
- install a 230 kV circuit breaker;
- install a 70 kV circuit breaker to connect the new transformer to the Arco 70 kV bus;
- re-insulate and extend the 70 kV main bus; and
- install a new 70 kV bus sectionalizing breaker and a 70 kV bus parallel breaker

Arco Substation (Arco) is located in the City of Lost Hills in Kern County. Arco is connected to the electric transmission grid via Midway-Arco 230 kV Line and Gates-Arco 230 kV Line.

Arco is currently a single-bank station serving approximately 103 MW of load and 3,200 customers with three single-phase 230/70 kV 44.8 MVA transformer units. This 1973-vintage transformer supplies radial load in the 70 kV transmission system composed of Blackwell, Antelope, Cholame, Devil's Den, Tulare Lake and Twisselman substations and large load customers such as Badger Hill, Chevron Lost Hills and Nations Petroleum. A sustained outage of Arco Transformer No. 1 results in a sustained outage to all of the customers served via the local 70 kV transmission system and 103 MW load is expected to be dropped. The total peak recorded load for 2011 was approximately 103 MW.

It is recommended to install a second, 230/70 kV transformer with a regulator at Arco Substation, install associated 230kV and 70 kV circuit breakers, install 70 kV bus parallel and sectionalizing breaker and extend the 70 kV bus. Upon completion of this project, the customers served via Arco will no longer experience momentary or sustained outages following a loss of Arco Transformer No. 1.

The ISO determined that the Arco #2 230/70kV transformer addition project as needed based on the BCR of 1.5 per ISO Grid Planning Standards, Section VI - 4. The project is expected to cost $15 million to $19 million with an expectation to be in service by 2013.

Cressey-Gallo 115kV line

PG&E submitted this project through 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope of work includes the following:

- construct a new 14.4 mile 115 kV transmission line from Cressey substation to Gallo substation and to convert Cressey and Gallo substations into loop substations.

The Atwater-Merced 115 kV Line is comprised of 15 miles of various conductor sizes and is constructed mainly on wood poles. The Atwater-Merced 115 kV line serves Livingston and Gallo substations via a 13-mile radial tap line from Atwater Junction. Livingston and Gallo substations serve approximately 6,100 electric customers (29.7 MW load).

The Atwater-Cressey 115 kV Line is comprised of 6 miles of various conductor sizes and is constructed mainly on wood poles. The Atwater – Cressey 115 kV Line is a radial source for Cressey, Dole and J.R. Wood substations. There are approximately 2,900 electric customers served from these three substations (26.8 MW of load).

Historical outage data shows that the Atwater-Merced 115 kV Line has an average of approximately 2.3 outages per year, due mainly to weather and car-pole accidents. The Atwater – Cressey 115 kV Line has an average of approximately one outage per year, due mainly to weather and car-pole accidents. The average outage rate for 115 kV lines in this area is 1.58 outages per year.

To reduce load outage exposure for the electric customers served in this area, this project proposes a new 14.4 mile 115 kV transmission line to be constructed from Gallo to Cressey substations. It is also recommended that two line circuit breakers be installed at both Gallo and Cressey substations to upgrade the bus configurations to loop arrangements.

The ISO determined that the Cressey-Gallo 115kV line project as needed based on the BCR of 1.5 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $15 million to $20 million with an expectation to be in service by 2013.

Gregg-Herndon #2 230kV circuit breaker upgrade

The project scope is to replace limiting terminal equipment at Herndon and possibly Gregg substations on the Herndon-Gregg #2 230 kV Line in order to return the line rating to 1,650 Amps under summer normal conditions and 1,950 Amps under summer emergency conditions.

This project protects against NERC Category C violations. The project is expected to cost $1 million to $2 million with an expectation to be in service by 2015.

The Herndon-Gregg #2 230 kV Line is located in Madera County. It is roughly 3,000 feet in length and crosses the San Joaquin river. The line conductor is bundled 1113 AAC which has a summer normal rating of 1,650 Amps, and a summer emergency rating of 1,950 Amps. The line is currently limited by circuit breaker 262 and its associated terminal equipment at the Herndon 230 kV switchyard; the line rating is therefore limited to 1,600 Amps for both summer normal and summer emergency conditions. The Herndon-Gregg 230 kV lines are important lines for exporting Helms PGP generation during the peak conditions, and for importing power to Helms PGP for pumping during off-peak conditions. Under multiple NERC Category C contingencies the Herndon-Gregg #2 230 kV line is projected to overload in 2013 above its 1,600 Amp rating. Until the limiting terminal equipment can be replaced operational switching solutions will take place in preparation for the second contingency.

Kearney #2 230/70kV transformer

PG&E submitted this project through 2012 Request Window per ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 4 reducing load outage exposure through a BCR above 1.0). The project scope of work includes the following:

Kearney Substation is located in Fresno County and is composed of two adjacent substations denoted as New Kearney (Kearney) and Old Kearney. These two substations are separated by local roads spanning 500 feet. The New and Old Kearney substations are electrically connected via the Kearney 70 kV Tie and the Alternate 70 kV Tie lines. Kearney Substation is connected to the transmission grid via the Herndon-Kearney and Panoche-Kearney 230 kV lines.

Kearney Transformer Bank No. 2 is composed of three single-phase 32 MVA, 230/70 kV transformer units. Kearney Transformer No. 2 serves the local 70 kV transmission system composed of Kearney, Biola, Bowles and Caruthers substations, and large load customer Fresno Waste Water. An outage of Kearney Transformer No. 2 results in a sustained outage to all of the approximately 16,000 customers served via the local 70 kV transmission system.

This project proposes to install a second, 230/70 kV transformer at Kearney Substation, build a four element 230 kV ring bus with MPAC and extend the 70 kV bus. Upon completion of this project, the customers served by Kearney, Biola, Bowles and Caruthers substations and Fresno Waste Water will no longer experience momentary or sustained outages following a loss of Kearney Transformer No. 2.

The ISO determined that the Kearney #2 230/70kV transformer project as needed based on the BCR of 1.82 per ISO Grid Planning Standards, Section VI-4. The project is expected to cost $32 million to $37 million with an expectation to be in service by 2015.

Kearney-Caruthers 70kV line reconductor

The project scope is to replace conductor on 12 miles of the Kearney-Caruthers 70 kV line with a conductor capable of at least 600 amps during summer normal and at least 700 amps during summer emergency conditions. The project is expected to cost $12 million to $18 million with an expectation to be in service by 2016.

This project is needed to meet load growth under normal conditions and to protect against NERC Category A violations.

The Kearney-Caruthers 70 kV line is located in Fresno County. A 230 kV source at Kearney provides power to customers at Caruthers substation on a single 70 kV line, this line is approximately 12 miles long. 11.85 miles are made up of 3/0 CU, while the remaining 0.03 miles is 397.5 AAC. Caruthers substation is normally fed from the Kearney substation source, while there is an additional back-tie from Henrietta and Kingsburg substations via the Caruthers-Lemoore NAS-Camden 70 kV Line.

Planning analysis has projected the 3/0 CU section of this line to overload sometime around 2022 under normal operating conditions, however PG&E’s distribution planning now anticipates load growth in this area to occur faster than originally expected. If this were the case, loading on the Kearney-Caruthers 70 kV Line could exceed the normal rating within the five year planning horizon.

Los Banos-Livingston Jct-Canal 70kV switch replacement

The project scope is to replace two limiting transmission line switches, #27 and #47, on the Los Banos-Livingston Junction-Canal 70 kV line, as well as any components of the transmission line that are more limiting than 715.5 AAC (631 Amps summer normal, and 742 Amps summer emergency). The new transmission line switches must be capable of at least 800 Amps during summer normal and emergency conditions. This project protects against NERC Category B violations. The project is expected to cost $0.5 million to $1 million with an expectation to be in service by 2015.

The Los Banos-Livingston Junction-Canal 70 kV line is located in Merced County and serves the Santa Nella, Canal, and Livingston 70 kV substations in addition to some customer owned facilities. The Los Banos substation to the west has two 230/70 kV transformers that serve the local 70 kV system, Oro Loma to the south-east provides a third source for the 70 kV system via a 115/70 kV transformer. Switches #27 and #47 on the Los Banos-Livingston Junction-Canal 70 kV line are 600 Amp KPF line switches, while the limiting line conductor is 715.5 AAC which has a summer normal rating of 631 Amps, and a summer emergency rating of 742 Amps. The 600 Amp line switches are expected to overload sometime around 2013 with the loss of the Oro Loma 115/70 kV transformer. There are current CAISO approved projects (the Oro Loma-Mendota 115 – 70 kV conversion and the Oro Loma 70 kV area reinforcement) which will indirectly alleviate this overload for the Oro Loma 115/70 kV transformer outage, however these projects are not expected to be completed until later years in the planning horizon and therefore this switch replacement is needed.

Northern Fresno 115 kV reinforcement

The project scope is as follows:

- build a new 230/115 kV substation that sectionalizes the Helms-Gregg #1 and #2 230 kV lines near where they cross the Kerckhoff-Clovis-Sanger #1 and#2 115 kV lines. The 230 kV bus will have two 230 kV lines to Gregg, two 230 kV lines to Helms, and two 420 MVA 230/115 kV transformers. In addition to the transformers, the 115 kV bus will also have two 115 kV lines to Kerckhoff PH2, two 115 kV lines to Sanger and one 115 kV line to Shepherd substation.
- install sectionalizing breaker at McCall substation between 230/115 kV transformer #1 and #2, and move the bus tie breaker to a new bay position;
- install sectionalizing breaker at Herndon substation between 230/115 kV transformer #2 and the new transformer #3;
- reconductor 18 miles of the Kerckhoff-Clovis-Sanger #1 and #2 115 kV lines from the new substation to Sanger substation;
- reconductor 9 miles of the McCall-Sanger #3 115 kV line;
- reconductor 22 miles of the Herndon-Woodward 115 kV line from Herndon to the new substation;
- replace terminal equipment as needed to achieve necessary conductor ratings;
- install one +/- 200 MVAR SVC at the new substation; and
- update Helms RAS if necessary.

All transmission line upgrades may be accommodated within the existing PG&E right of ways (Brownfield) with very little new right of way acquisitions. It is expected that the new substation will require land acquisition and permitting. This project protects against NERC Category B violations. The project is expected to cost between $110 million and $190 million with an expectation to be in service by 2018.

Herndon 230 kV substation is located in Fresno County. Herndon is the main source of power for northern Fresno and surrounding areas. The 230 kV bus at Herndon is a double bus single breaker design. A fault on the 230 kV bus tie breaker will cause overloads of up to 200 percent on 10 lines and low voltage throughout Fresno. The existing Kerckhoff PH2 SPS will activate and trip Kerckhoff PH2 causing voltages to drop further. In response to the low voltages McCall UVLS will activate dropping 260 to 290 MW of load in Metro Fresno. After all SPS have acted, there will still be overloads of up to 140 percent on 7 lines. To mitigate these overloads, operators could drop an additional 240 to 260 MW of load via SCADA, bringing the total load dropped to between 500 and 550 MW. This outage may lead to voltage collapse under some conditions; then the amount of load dropped could be substantially higher.

The main source of power for Southern Fresno is McCall 230 kV substation. A fault on the 230 kV bus tie breaker at McCall substation would cause overloads of up to 126 percent on 4 facilities and low voltage throughout Southern Fresno. McCall UVLS would initiate for this contingency and drop 260 to 290 MW of load. An additional 50 MW of load may need to be dropped via SCADA to alleviate overloads of the Herndon-Barton and Herndon-Manchester 115 kV lines. This outage may also lead to voltage collapse, in which case the consequences for this outage could be more severe.

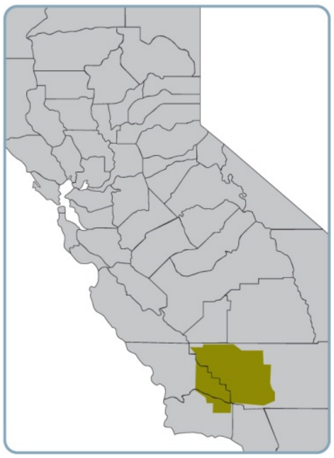
There are several other outages that lead to overloads. During peak load conditions, the Herndon 230/115 kV transformers #1, #2 and #3, McCall 230/115 kV transformers #1, #2 and #3, Herndon-Barton 115 kV line and Herndon-Manchester 115 kV line all overload for NERC Category C2 and C3 (N-1-1) outages. In order to take clearances at McCall, extensive switching would need to be performed to radialize the 115 kV system. This would make routine maintenance difficult and expensive, and would significantly increase the risk of customer outages.

The Northern Fresno 115 kV Area Reinforcement project will strengthen the system so that it can withstand the Herndon 230 kV bus tie breaker fault without relying on SPS or dropping any load. The system will also be strengthened enough to withstand the McCall 230 kV bus-tie breaker fault and will mitigate overloads on 20 additional facilities resulting from at least 10 separate contingencies. This project will also increase operating flexibility, load serving capability, customer reliability and reduce losses. The impact on Helms pumping capability will be negligible.

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 area 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 2,095 MW by 2022. 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 2.5-16 lists a summary of the generation in the Kern area, with detailed generation listed in Appendix A.

Table 2.5-16: Kern area generation summary

Generation	Capacity (MW)
Thermal	3,437
Hydro	22
Solar	73
Biomass	56
Total	**3,588**

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 2.5-17 shows loads in the Kern area assessment.

Table 2.5-17: Load forecasts modeled in the Central Valley area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		
	2014	2017	2022
Kern	1,776	1,799	1,816

2.5.7.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study of the northern Kern area yielded the following conclusions:

- No overloads and no voltage concerns would occur under normal conditions.
- Three overloads and multiple low voltage concerns would occur under single (Category B) contingency conditions.
- Multiple overloads and low voltage concerns caused by multiple (Category C) contingencies would occur under all studied conditions.

To mitigate the identified thermal overloads and low voltage concerns, the ISO recommends the Midway-Temblor Reconductor transmission project described below.

Midway-Temblor 115 kV Reconductor and Voltage Support

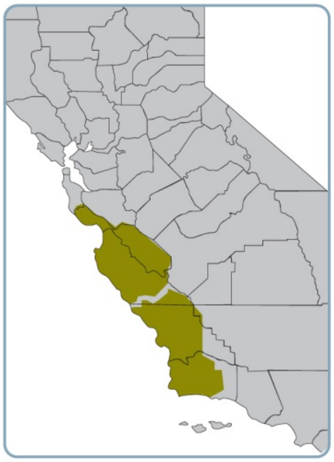
The project scope is to replace conductor on 15 miles of the Midway-Temblor 115 kV line with a conductor capable of at least 600 amps during summer normal and at least 700 amps during summer emergency conditions, and install 40 MVARs of shunt capacitors at Temblor substation in 8 MVAR steps. The project is expected to cost $25 million to $35 million with an expectation to be in service by 2018.

This project protects against NERC Category B violations.

The Midway-Temblor 115 kV line is located in Kern County. Temblor substation is fed by San Luis Obispo substation from the West, and Midway substation from the East. The Midway-Temblor 115 kV line is made up of 14.4 miles of 336.4 AAC, and 0.1 miles of 397.5 AAC conductors. The PSE McKittrick tap is located roughly 300 feet outside of Temblor substation and is tapped off the Midway-Temblor 115 kV Line. Loss of generation in the Temblor 115 kV area is projected to increase flows on the Midway-Temblor-San Luis Obispo path and overload the 336.4 AAC section of the Midway-Temblor 115 kV Line by 2014. Additionally, with the Midway-Temblor 115 kV line outage and local generation in the Temblor area out of service, voltages at Temblor and surrounding substations are expected to be below planning thresholds by 2013. In the interim until the project is in-service action plans will be utilized which may include operating the Temblor and Carrizo substations radially from their San Luis Obispo and Midway 115 kV sources respectively.

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 the following: Santa Cruz-Watsonville, Monterey-Carmel and Salinas- Soledad-Hollister sub-areas, which are supplied via 115 kV double circuit tower lines; King City, is an area supplied by 230 kV lines from the Moss Landing and Panoche substations; and 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 other 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, Templeton, Paso Robles and Atascadero are among the cities that PG&E provides electric service to within this division. The City of Lompoc, a member of the Northern California Power Authority (NCPA), is also located in this area. Counties in the area include San Luis Obispo and Santa Barbara. The 2,400 MW Diablo Canyon Nuclear Power Plant (DCPP) is also located in Los Padres. Most of the power generated from the Diablo Canyon power plant is exported to the north and the east through bulk 500 kV transmission lines, hence it has very little impact on the Los Padres area operations. 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 709 MW including the 680 MW Morro Bay Power Plant. This does not include the 2,400 MW of DCPP

Load forecasts indicate that the Central Coast and Los Padres areas Summer Peak demand will be 796 MW and 606 MW respectively by 2017. By 2022, the Summer Peak loading for Central Coast and Los Padres would be 841 MW and 640 MW, respectively. Winter Peak demand forecasts in Central Coast are approximately 661 MW in 2017 and 701 MW in 2022. Since this area is along the coast, it has a dominant Winter Peak load profile in certain pockets (e.g., the

Monterey-Carmel sub-area). Winter Peak demands in these pockets could be as high as 10 percent more than some of the other load pockets in the area. 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. Table 2.5-18 lists a summary of the generation in the Central Coast and Los Padres area, with detailed generation listed in Appendix A.

Table 2.5-18: Central Coast and Los Padres area generation summary

Generation	**Capacity (MW)**
Thermal	3,590
Nuclear	2,400
Total	**5,990**

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 2.5-19 and Table 2.5-20 shows loads modeled for the Central Coast and Los Padres areas assessment.

Table 2.5-19: Load forecasts modeled in the Central Coast and Los Padres area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area	Summer Peak (MW)		
	2014	2017	2022
Central Coast	770	797	841
Los Padres	578	606	640
TOTAL	**1,348**	**1,403**	**1,481**

Table 2.5-20: Load forecasts modeled in the Central Coast and Los Padres area assessment

1-in-10 Year Heat Wave Non-Simultaneous Load Forecast			
PG&E Area	Winter Peak (MW)		
	2014	2017	2022
Central Coast	637	661	701
Los Padres	417	438	464
TOTAL	**1,054**	**1,099**	**1,165**

2.5.8.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The summer and Winter Peak reliability assessment for the PG&E Central Coast and the summer reliability assessment for the Los Padres area that was performed in 2012 confirmed previously identified reliability concerns. The concerns consist of thermal overloads, low voltages and voltage deviations under Category B and C contingency conditions. Unlike the previous years, no Category A concerns were identified. The previously approved projects, which include the Watsonville 115 kV Voltage Conversion, Crazy Horse Substation, Natividad Substation and Moss Landing 230/115 kV Transformer Replacement 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.

To address the identified thermal overloads and low voltage concerns, the ISO recommends the following transmission development projects in the area as a part of the mitigation plan.

Midway-Andrew 230 kV Project

The Midway-Andrew 230 kV Project will fully mitigate the voltage collapse problems presently observed in the Mesa and Divide 115 kV system and protect against approximately 270 MW of load drop following loss of any two of the 230 kV sources at the Mesa substation (Category C5, C2 and C3 outages). For the Divide area, the project will avert system voltage collapse and protect against approximately 145 MW of load shedding following loss of Mesa-Divide #1 & 2 115 kV Lines.

Making use of the existing transmission right of way, the project converts the existing idle Midway-Santa Maria 115 kV line into a new Midway-Andrew 230 kV line, installs one new three-phase 420 MVA 230/115 kV transformer bank at Andrew and loops the Andrew 115 kV bus into Santa Maria-Sisquoc and Mesa-Sisquoc 115 kV lines. It also connects the Andrew 115 kV bus to the Divide substation with a new 10-mile Andrew-Divide #1 115 kV Line. The estimated cost of the project is $120 million to $150 million with an estimated in-service date of May 2019.

The project provides a more robust system reinforcement by introducing another source to the Los Padres 115 kV system (in addition to Mesa and Divide). This additional new source reduces the overly dependence on the Mesa substation as the only source feeding the Mesa 115 kV system. It also enhances planned system maintenance and clearance options.

It is to be noted that the Los Padres Transmission Project that installed SPS at both Mesa and Santa Maria 115 kV Substations was approved as an interim solution to address the Mesa voltage collapse problem by dropping approximately 270 MW load. The Divide SPS Project was also approved and installed as an interim solution to mitigate the voltage collapse problems in the Divide 115 kV area following loss of Mesa-Divide #1 & 2 115 kV lines. With the implementation of the Midway-Andrew 230 kV Project, the Divide SPS Project will no longer be needed and the existing Los Padres Transmission Project will be modified to only protect against potential San Luis Obispo-Santa Maria #1 115 kV Line overload under Summer Peak conditions following loss of Morro Bay-Diablo and Morro Bay Mesa 230 kV Lines by tripping the Santa Maria circuit breaker No. 132 to open-end the San Luis Obispo-Santa Maria 115 kV Line. Thus, the other SPS that forms part of the Los Padres Transmission Project and trips the Mesa circuit breaker No. 132 will also no longer be needed.

Diablo Canyon Voltage Support Project

The *Diablo Canyon Voltage Support Project* will install a new Static Var Compensator (SVC) or thyristor controlled switched capacitor bank rated at +150 MVAr at the Diablo Canyon 230 kV substation and construct the associated bus to provide voltage control and support for the Diablo Canyon Power Plant (DCPP). The project is needed in 2017 to address NERC NUC-001-2, NERC TPL Standards Category C (C3/C5) contingencies resulting in low voltages below 0.90 pu. The critical outages involve the loss of Morro Bay – Diablo 230 kV line and Morro Bay-Mesa

230 kV Line resulting in low voltages at the Diablo and Mesa 230 kV buses and extending to the Mesa 115 kV system. The estimated cost of the project is $35-$45 Million at an estimated in-service date of May 2016.

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. 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. The SCE service area is shown in map on the left. The CEC's load growth forecast for the entire SCE area is about 365 MW per year. The CEC's 1-in-10 heat wave load forecast includes the SCE service area, the Anaheim Public Utilities, the City of Vernon Light & Power Department, the Pasadena Water and Power Department, the Riverside Public Utilities, the California Department of Water Resources and the Metropolitan Water District of Southern California loads. The 2017 and 2022 Summer Peak forecast loads are 26,787 MW and 28,502 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 161 kV, 115 kV and 66 kV network transmissions. The bulk system includes six areas: Metro, Tehachapi and Big Creek Corridor, 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 Tehachapi and Big Creek Corridor 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 systems 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, 230 kV transmission system from Devers to Julian Hinds and 161 kV transmission system from Eagle Mountain to Blythe.

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 ISO-secured website lists the base cases and contingencies that were studied as part of this assessment. In addition, specific assumptions and methodology that were applied to the SCE area study are provided below.

Generation

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. A summary of generation is provided in each of the local planning areas within the SCE area.

Load Forecast

The SCE area Summer Peak base cases assume the CEC 1-in-10 year heat wave load forecast. The consolidated Southern California Summer Peak base cases assume the CEC 1-in-5 year heat wave load forecast.

Table 2.6-1 provides a summary of the SCE coincident substation 1-in-10 year heat wave load forecast in the Summer Peak assessment.

The Summer Light Load and Spring Off-Peak base cases assume 50 percent and 65 percent of the coincident 1-in-2 year heat wave load forecast, respectively.

Table 2.6-1: Summer Peak load forecasts modeled in the SCE area assessment

Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
	2014	**2017**	**2022**
SCE Area	**24,730**	**25,731**	**27,431**

2.6.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. All system performance requirements were met in the analysis of the SCE area bulk system base cases under Category A and B conditions. Recommended solutions that address the identified facility that did not meet the performance requirement under Category C condition are discussed in section 2.7.4.

2.7 SCE Local Areas Assessment

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

2.7.1 Tehachapi and Big Creek Corridor

2.7.1.1 Area Description

The Tehachapi and Big Creek Corridor area consists of the SCE transmission system north of Vincent. The area includes the following:

- WECC Path 26 — three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation with Whirlwind 500 kV loop-in to the third line;
- Tehachapi area — Windhub – Whirlwind 500 kV, Windhub – Antelope 500 kV, and two Antelope – Vincent 500 kV lines;
- 230 kV transmission system between Vincent and Big Creek Hydroelectric project that serves customers in Tulare county; and
- Antelope-Bailey 66 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

There are three major transmission projects that have been approved in prior cycles by the ISO in this area, which are as follows:

- San Joaquin Cross Valley Loop Transmission Project (in-service date: 2014);
- Tehachapi Renewable Transmission Project (in-service date: 2015); and
- East Kern Wind Resource Area 66 kV Reconfiguration Project (in-service date: 2014).

2.7.1.2 Area-Specific Assumptions and System Conditions

The Tehachapi and Big Creek area study was performed consistent with the general study methodology and assumptions described section 2.3. As described in section 0, two cases were studied for the area: 1) with new renewables; in which some potentially planned renewable generation projects were modeled; 2) without new renewables; in which potentially planned renewable generation projects were not modeled.

The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study area are provided below.

Generation

Table 2.7-1 lists a summary of the generation in the Tehachapi and Big Creek area, with detailed generation listed in Appendix A.

Table 2.7-1: Tehachapi and Big Creek area generation summary

Generation	Capacity (MW)
Thermal	1,586
Hydro	1,139
Wind	1,177
Total	**3,902**

Load Forecast

The ISO Summer Peak base case assumes the CEC's 1-in-10 year heat wave load forecast and includes system losses. Table 2.7-2 shows the Tehachapi and Big Creek area load in the Summer Peak assessment cases excluding losses.

The ISO Summer Light Load and Spring Off-Peak base cases assume 50 percent and 70 percent of the 1-in-2 year heat wave load forecast, respectively.

Table 2.7-2: Summer Peak load forecasts modeled in the SCE's Tehachapi and Big Creek area assessment

Tehachapi and Big Creek Area Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Antelope-Bailey 220/66 kV	731	777	838
Rector 220/66 kV	732	734	785
Springville 220/66 kV	233	244	251
Vestal 220/66 kV	134	137	141
Big Creek 220/33 kV	9	9	9

2.7.1.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The reliability assessment with and without new renewable generation did not indicate any system performance concerns.

2.7.2 Antelope-Bailey

2.7.2.1 Area Description

The Antelope-Bailey area is composed of the ISO Controlled 66 kV transmission facilities connected between Antelope and Bailey substations.

One major transmission project, the East Kern Wind Resource Area (EKWRA) 66 kV Reconfiguration Project (in-service date: 2014) was modeled in the base cases.

Once the transmission project is in-service, the area will consist of the Antelope-Bailey-Windhub 66 kV system.

2.7.2.2 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 renewables; in which some potentially planned renewable generation projects were modeled; 2) without new renewables; in which potentially planned renewable generation projects were not modeled.

The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study area are provided below.

Generation

Table 2.7-3 lists a summary of the generation in the Antelope-Bailey area, with detailed generation listed in Appendix A.

Table 2.7-3: Antelope-Bailey area generation summary

Generation	**Capacity (MW)**
Hydro	34
Wind	355
Total	**389**

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 2.7-4 shows the Antelope-Bailey area load in the Summer Peak assessment cases excluding losses.

The ISO Summer Light Load and Spring Off-Peak base cases assume 50 percent and 61 percent of the 1-in-2 year heat wave load forecast, respectively.

Table 2.7-4: Summer Peak load forecasts modeled in the SCE's Antelope-Bailey area assessment

Antelope-Bailey Area Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year Heat Wave)			
Area	**2014**	**2017**	**2022**
Antelope-Bailey 220/66 kV	731	777	838

2.7.2.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The Summer 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 C contingency conditions. Based on the assessment results, the ISO plans to develop operating procedures to manually shed load and manually switch in shunt capacitors to address the identified reliability concerns to meet the ISO standards for the area.

2.7.3 North of Lugo Area

2.7.3.1 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.

2.7.3.2 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. As described in section 2.3, two cases were studied for the area: 1) with new renewables; in which some potentially planned renewable generation projects were modeled; 2) without new renewables; in which potentially planned renewable generation projects were not modeled.

The ISO-secured website lists the base cases and contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study area are provided below.

Generation

Table 2.7-5 lists a summary of the generation in the North of Lugo area, with detailed generation listed in Appendix A.

Table 2.7-5: North of Lugo area generation summary

Generation	Capacity (MW)
Thermal	1,728
Hydro	55
Solar	376
Geothermal	291
Total	**2,450**

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 shows the North of Lugo area load in the Summer Peak assessment cases excluding losses.

The ISO Summer Light-Load base case assumes 50 percent of the 1-in-2 year heat wave load forecast. The Spring Off-Peak base case assumes 62 percent of the 1-in-10 year heat wave load forecast.

Table 2.7-6: Load forecasts modeled in the North of Lugo area

North of Lugo Area Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Kramer 220/115	464	496	544
Victor-Kramer-Inyo 220/115	832	876	964

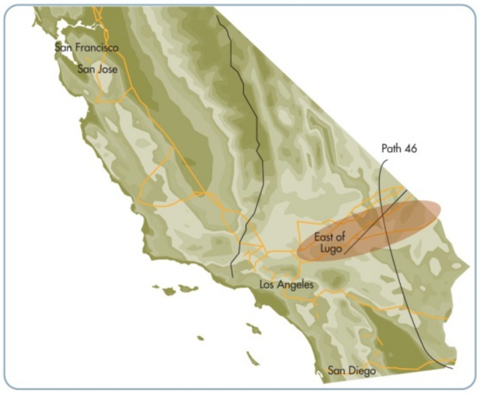
2.7.3.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The Summer Peak reliability assessment of the North of Lugo area revealed several reliability concerns. These concerns consist of high/low voltages, and voltage deviations under Category B and C contingency conditions. Based on the assessment results, the ISO proposes to install or reconfigure the existing shunt reactors, install shunt capacitor, and SPS to shed load to address the identified reliability concerns in the North of Lugo area.

2.7.4 East of Lugo

2.7.4.1 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), and is heavily integrated with LADWP and other neighboring transmission systems. The SDG&E owned Merchant 230 kV switchyard became part of the ISO Controlled Grid and now radially connects to the joint-owned Eldorado 230 kV substation. Merchant substation was formerly in the NV Energy Balance Authority, but after a system reconfiguration in 2012, became part of the CAISO system. 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 Cool Water to Eldorado
- 500 kV and 230 kV tie lines with neighboring systems

2.7.4.2 Study 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. The ISO-secured website lists the base cases and 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 some potentially planned renewable generation projects were modeled; 2) without new renewables; in which potentially planned renewable generation projects were not modeled. In addition, specific assumptions and methodology that applied to the East of Lugo area study are provided below.

Transmission

The CPUC and the ISO approved the Eldorado-Ivanpah Transmission Project, a new 220/115 kV Ivanpah substation and an upgrade of a 35-mile portion of an existing transmission line connecting the new substation to Eldorado Substation with projected in service date of July 2013.

In light of the FERC approved Transition Agreement between CAISO and Valley Electric Association, the planned interconnection tie between VEA's newly proposed 230 kV Bob Switchyard and SCE's new 220 kV Eldorado substation is assumed to be in service on the year 2016.

Generation

There are about 553 MW of existing generation connected to the SDG&E owned Merchant substation, and about 400 MW of renewable generation in the Ivanpah area (under construction, and to be in service by the year 2013). Table 2.7-7 lists a summary of the generation in the East of Lugo area, with detailed generation listed in Appendix A.

Table 2.7-7: Generation in the East of Lugo area

Generation	Capacity (MW)
Thermal	495
Solar	458
Total	**953**

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 but excludes power plant auxiliary loads in the area. The SCE Summer Light Load base cases assume 50 percent of the 1-in-2 year heat wave load forecast.

Table 2.7-8 provides a summary of the Eldorado area load in the Summer Peak assessment.

Table 2.7-8: Summer Peak load forecasts modeled in the East of Lugo area assessment

Substation	2014	2017	2022
Eldorado Area (MW)	25	25	25

2.7.4.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2012-2022 Summer Peak and Spring Off-Peak reliability assessment of the SCE East of Lugo area identified two reliability concerns that require mitigation in the current planning cycle. The ISO recommends the following operating solution and modification to SPS previously identified in GIP to mitigate the concerns

- To extend the existing ISO Operation Procedure No. 6610 (SCE's SOB T-135) to cover the Eldorado-Lugo 500 kV line overload under the L-1-1 outage of the Lugo-Victorville 500 kV line and the Palo Verde-Colorado 500 kV line with the development of renewables in 2022

- To modify the SPS previously identified in GIP to trip generation in the Pisgah, Ivanpah-Eldorado areas, and VEA's Crazy Eye 230 kV substation to cover thermal overload, voltage deviation concern, and power flow divergence, or apply congestion management to curtail generation after first contingency as needed.

2.7.5 Eastern Area

2.7.5.1 Area Description

The ISO-controlled grid in the Eastern Area serves the portion of Riverside County roughly west of the Devers Substation. The figure below depicts the geographic location of the area. The system is composed of 500 kV, 230 kV, 161 kV and 115 kV transmission facilities from Devers Substation to Palo Verde Substation in Arizona. The area has ties to APS, IID, MWD, and WALC facilities.

The ISO approved the following major transmission projects in this area in prior planning cycles:

- Valley-Devers-Colorado River 500 kV Transmission Project (in-service date: 2013)
- Devers-Mirage 115 kV Split Project (in-service date: 2013)
- Coachella-Devers 230 kV Loop-in Project (in-service date: 2013).

The ISO intends to relinquish control of the Devers-Mirage area sub-transmission facilities once the system is split.

2.7.5.2 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. As described in section 2.3.2.5, two sets of base cases were studied for the area: 1) with new renewable projects, in which some potentially planned renewable generation projects were modeled; 2) without new renewables, in which potentially planned renewable generation projects were not modeled. The ISO-secured participant portal lists the base cases and contingencies that were studied.

Additionally, specific assumptions and methodology that were applied to the Eastern Area study are provided below.

Generation

Table 2.7-9 lists a summary of the generation in the Easter area, with detailed generation listed in Appendix A.

Table 2.7-9: Eastern area generation summary

Generation	**Capacity (MW)**
Thermal*	1,506
Wind	772
Solar*	250
Total	**2,528**

Note: * The capacity shown includes generation currently under construction.

Load Forecast

The ISO Summer Peak base case assumes the CEC 1-in-10 year heat wave load forecast. The forecast load includes system losses. Table 2.7-10 provides a summary of the Eastern Area coincident substation load used in the Summer Peak assessment.

The Summer Light Load and Spring Off-Peak base cases assume 50 percent and 70 percent of the 1-in-2 year heat wave load forecast, respectively.

Table 2.7-10: Summer Peak load forecasts modeled in the Eastern Area assessment

Eastern Area Coincident Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Blythe	65.9	67.3	69.4
Bottle	17.3	22.9	30.4
Camino	2.0	2.0	2.0
Carodean	18.1	19.8	24.8
Concho	66.5	70.0	70.1
Devers	21.3	23.2	25.8
Eagle Mountain	1.3	1.3	1.3
Eisenhower	118.9	120.5	126.7

Eastern Area Coincident Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Farrell	102.1	105.3	112.1
Garnet	89.5	97.7	111.0
Hi Desert	34.2	35.3	35.4
Indian Wells	110.8	114.1	125.4
Leatherneck	19.5	19.5	19.5
Santa Rosa	202.2	210.1	226.5
Tamarisk	115.1	120.3	133.9
Thornhill	51.3	56.2	59.8
Yucca	44.3	45.7	49.2
Total	**1,080.3**	**1,131.2**	**1,223.3**

2.7.5.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2013-2022 reliability assessment for the SCE Eastern Area identified three reliability concerns that require mitigation in the current planning cycle. The ISO recommends the following solutions to mitigate the concerns identified:

- modify the planned Mirage 115 kV RAS to drop load following the overlapping outage of two of the three Mirage 230/115 kV banks (Category C.3) to mitigate overloading of the remaining bank;
- apply congestion management to mitigate voltage deviation concerns associated with outage of the Palo Verde–Colorado River 500 kV line and the subsequent action of the Blythe Energy RAS The ISO intends to develop and implement flow limits for use in managing the congestion. The flow limit is not expected to be binding in the ISO market for more than a few hours a year. The ISO also recommends installing controls to automate the switching of the existing Eagle Mountain shunt capacitor in response to area voltages; and

- install an SPS to trip the Eagle Mountain–Blythe 161 kV line to limit the impact of an N-1-1 outage involving Julian Hinds–Mirage 230 kV line and either the Iron Mountain–Camino–Mead–Gene or Eagle Mountain–Iron Mountain 230 kV lines when local generation is offline.

Until the SPS is in place, the ISO recommends manually opening the Eagle Mountain-Blythe 161 kV line following outage of any one of the critical 230 kV lines when local generation is unavailable. The ISO intends to update the applicable operating procedure to document the recommended temporary operator action.

2.7.6 Metro Area

2.7.6.1 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.

The ISO approved the following major transmission projects in this area in prior planning cycles:

- loop Del Amo-Ellis 230 kV line into Barre Substation (already in service);
- method of Service for El Casco 230/115 kV Substation (in-service date: 2013);
- method of Service for Alberhill 500/115 kV Substation (in-service date: 2015); and
- method of Service for Wildlife 230/66 kV Substation (in-service date: 2015).

2.7.6.2 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.

The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. In addition, specific assumptions and methodology that were applied to the Metro area study are provided below.

Generation

Table 2.7-11 lists a summary of the generation in the Metro area, with detailed generation listed in Appendix A.

Table 2.7-11: Metro area generation summary

Generation	Capacity (MW)
Thermal	12,323
Hydro	319
Nuclear	2,246
Biomass	120
Total	**15,008**

Load Forecast

The ISO Summer Peak base case assumes the CEC 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.7-12 provides a summary of the Metro area substation load in the Summer Peak assessment.

The Summer Light Load and Spring Off-Peak base cases assume 50 percent and 65 percent of the coincident 1-in-2 year heat wave load forecast, respectively.

Table 2.7-12: Summer Peak load forecasts modeled in the Metro area assessment

Metro Area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Alamitos 220/66 (S)	199	208	228
Chino 220/66 (S)	726	721	904
Del Amo 220/66 (S)	556	570	588
Etiwanda Ameron (S)	18	18	18
El Nido 220/66 (S)	415	426	442
Etiwanda 220/66 (S)	704	771	816
Goleta 220/66 (S)	327	336	356
Hinson 220/66 (S)	424	427	431
La Fresa 220/66 (S)	732	764	814
Vernon	506	510	509
Lighthipe 220/66 (S)	464	476	489
Moorpark 220/66 (S)	715	754	827
Padua 220/66 (S)	663	681	715
Santa Clara 220/66 (S)	470	506	569
Santiago 220/66 (S)	851	907	688
Saugus 220/66 (S)	851	899	1,001
Walnut 220/66 (S)	642	656	679

Metro Area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
Valley C 500/115 (S)	695	767	895
Ellis 220/66 (S)	644	670	717
Chevmain 220/66 (S)	167	168	169
Barre 220/66 (S)	702	710	741
Center 220/66 (S)	461	464	475
Eagle Rock 220/66 (S)	225	266	303
Gould 220/66 (S)	148	155	169
Johanna 220/66 (S)	494	561	581
La Cienega 220/66 (S)	501	519	568
Mesa 220/66 (S)	632	640	670
Mira Loma 220/66 (S)	727	760	724
Olinda 220/66 (S)	409	417	433
Rio Hondo 220/66 (S)	730	748	773
San Bernardino 220/66 (S)	652	667	699
Villa Park 220/66 (S)	739	719	753
Valley AB 500/115 (S)	805	881	998
Alberhill 500/115 (S)	320	328	350
Vista 220/66 (S)	937	656	682
Vista 220/115 (S)	299	311	320
Wilderness 220/66 (F)	0	313	338
Goodrich 220/33 (S)	333	342	360
Lewis 220/66 (S)	646	673	710
Viejo 220/66 (S)	370	382	669

Metro Area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year Heat Wave)			
Substation	**2014**	**2017**	**2022**
El Casco 220/115 (S)	228	246	279

2.7.6.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The reliability assessment identified thermal and voltage concerns in the Metro area of the SCE system under contingency conditions. The ISO recommends the following mitigation measures to address each of the identified reliability concerns:

- develop an SPS to address an overload on Barre-Del Amo 230 kV line under a Category C contingency; and
- add shunt capacitors at Viejo to address a Viejo 230 kV bus post-transient voltage deviation concern under a Category B contingency.

The ISO received four proposals for four transmission projects in the Metro area through the 2012 Request Window, which are related to the reliability concerns identified in the 2013 SONGS absence scenario. The study results and discussion of the four proposals for the 2013 SONGS absence scenario are summarized in chapter 3.

In the 2022 Summer Peak cases, one facility, Viejo 230 kV bus, did not meet TPL-002 post-transient voltage deviation requirements for a G-1/L-1 outage of San Onofre-Viejo 230 kV line with one San Onofre generating unit out of service.

The ISO determined that the Viejo capacitor banks project was needed to mitigate the reliability concerns identified in both the 2013 SONGS absence scenario and the 2022 case. In order to mitigate the 2013 reliability concerns, ISO management approved this project following the briefing to the ISO Board of Governors at the September 2012 Board of Governors meeting. The project is described below.

Viejo 230 kV Capacitor Banks Project.

The project scope includes the following:

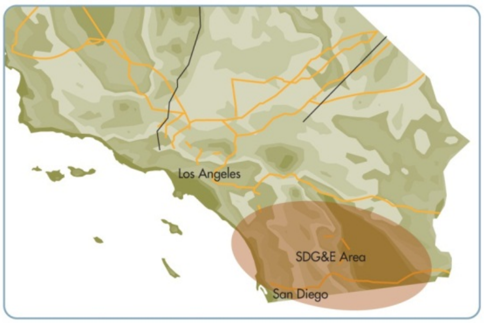
- install two 79.2 MVAR capacitor banks at Viejo Substation for a total of 158.4 MVAR of voltage support in southern Orange County.

The project is expected to cost $10 million and has an in-service date of July 2013.

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 840,000 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 US-Mexico border.[13]



SDG&E system 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, Suncrest 500/230kV substation and the Otay Mesa-Tijuana 230 kV transmission line.

Historically, the SDG&E import capability is 2,850 MW with all facilities in-service and 2,500 MW with SWPL out-of-service. When the Sunrise Powerlink project became operational, the import capability with all lines in service increased to 3,400 MW.

In addition to imports, 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, two wind farms.

The SDG&E transmission system consists of 500 kV Southwest Power Link (North Gila - Imperial Valley - Miguel), 500kV Sunrise Power Link (Imperial Valley - Suncrest) and 230 kV, 138 kV and 69 kV transmission. The 500 kV substations include Imperial Valley 500/230 kV, Miguel 500/230/138/69 kV and Suncrest 500/230kV.

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 US-Mexico border and to the Suncrest and Imperial Valley substations in the East. 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego.

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 (Bay Blvd) and Miguel substations in the south. There is also a radial 138 kV arrangement with seven 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.

[13] These numbers are provided by SDG&E in the 2011 Transmission Reliability Assessment

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 study base cases and 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 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.

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 and two SDG&E peakers at Miramar Substation (MEF) (46 MW each). 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 and 299 MW Ocotillo Express wind farm which became operational in December 2012. Lake Hodges pump-storage plant (40 MW) is composed of two 20 MW units. Both units are operational as of summer of 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 dispatched in all study years.

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.

Table 2.8-1 lists a summary of the generation in the San Diego area, with detailed generation listed in Appendix A.

Table 2.8-1: San Diego area generation summary

Generation	**Capacity (MW)**
Thermal	3,011
Hydro	40
Wind	8.3
Solar	299
Biomass	23.9
Total	**3,382.2**

Load Forecast

Loads within the SDG&E system reflect a coincident peak load for 1-in-10-year heat wave conditions. The load for 2017 was assumed at 5,347 MW, and transmission losses were 137 MW. The load for 2022 was assumed at 5,845 MW, and transmission losses were 159 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 2.8-2summarizes load in SDG&E and the neighboring areas and SDG&E import modeled for the study horizon.

Table 2.8-2: Load, losses and import modeled in the SDG&E study

PTO	2014		2017		2022	
	Load, MW	**Losses, MW**	**Load, MW**	**Losses, MW**	**Load, MW**	**Losses, MW**
SDG&E	5,045	132	5,347	137	5,845	159
SCE	25,325	463	27,362	452	27,067	459
IID	995	35	1,061	51	669	39
CFE	2,401	36	2,910	48	1726	21
SDG&E Import	3,402	-	3,401	-	3,660	-

Power flow cases for the study modeled a load power factor of 1.0 in the study year 2014 and 0.991 lagging at nearly all load buses in 2017 and 2022. The number for 2014 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.

- 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.

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.

2.8.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO initially proposed a total of seven 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 2012 Request Window. Out of these projects, some were alternatives for solving the same problems.

To address the identified reliability concerns, the ISO recommends the following transmission development projects in the area as a part of the mitigation plan.

TL13820, Sycamore-Chicarita Reconductor

This line is expected to be overloaded for a Category B contingency of Encina 230/138 bank 60 starting in 2019 (after the retirement of Encina). SDG&E submitted a project to reconductor this line — TL13820, Sycamore-Chicarita Reconductor. The project scope involves replacing underground getaways, relays, jumpers and terminal equipment. The project is expected to cost $0.5 to $1 million and the expected in-service date is June, 2014.

TL674A Loop-in (Del Mar – North City West) & Removal of TL666D (Del Mar – Del Mar Tap)

This is a project submitted by SDG&E to remove from service the existing Rancho Santa Fe Tap and TL666D (Del Mar – Del Mar Tap) and to loop-in TL674A at Del Mar substation. This need is driven by challenges in outage restoration and maintenance of aging infrastructure due to environmental concerns. TL666D crosses multiple environmentally sensitive areas and cannot be accessed by bucket trucks. This has resulted in a very high forced outage rate on this line (almost 3 times as many forced outages on this line compared to other lines in this area). The removal of TL666D would cause Category B and C voltage deviation issues. These issues would be mitigated by looping in TL674A at Del Mar 69kV. This project will eliminate segment D of TL666 (DM-TP-PN-DB-DU) and Loop-in TL674A into Del Mar creating a Del Mar – North City West circuit rated at 136 MVA and a Encinitas –Rancho Santa Fe circuit rated at 97/102 MVA. This will result in elimination of one three-terminal line (TL674), replacing TL666D with a stronger source to Del Mar, and reducing the exposure to the remaining portions of TL666 to unplanned, possibly long-term outages. The project is expected to cost $12 to $15 million and the expected in-service date is June, 2015.

Sweetwater Reliability Enhancement

Sweetwater – Sweetwater Tap 69kV line section is expected to be overloaded for a Category B (G-1/N-1) contingency of division QF and TL23026, Silvergate-Bay Boulevard 230 kV line starting in 2017. SDG&E submitted a project to reconfigure Sweetwater Tap - Sweetwater Reliability Enhancement. This project will mitigate the Category B overload in time. As part of this project, Sweetwater Tap will be removed from service and existing TL603A (Naval Station Metering – Sweetwater Tap) will be extended from NSM into Sweetwater Substation to achieve a minimum continuous/emergency rating of 180 MVA. TL603D (National City – Sweetwater Tap) and TL603B (Sweetwater – Sweetwater Tap) will be made into one continuous line segment running from National City to Sweetwater Substation to achieve a minimum continuous/emergency rating of 102 MVA. The project is expected to cost $10 to $12 million and the expected in-service date is June, 2017.

The following 4 projects are evaluated as part of the no-SONGS scenario:

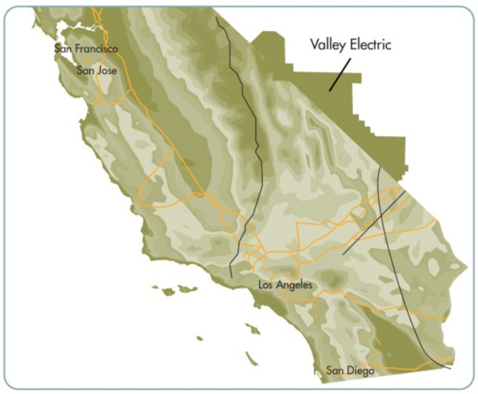
- install Synchronous Condensers at Mission 230 kV Substation;
- install Synchronous Condensers at Penasquitos 230 kV Substation;
- install Synchronous Condensers at Sycamore 230 kV Substation; and
- install Synchronous Condensers at Talega 230 kV Substation.

Refer to chapter 3 for assessment and recommendation information.

2.9 Valley Electric Association

2.9.1 Area Description

The existing Valley Electric Association (VEA) system consists of the original backbone 138 kV system which originates at the Amargosa Substation and extends to the Pahrump Substation and then on into the VEA service area, the Pahrump-Mead 230 kV line, and a planned major 230 kV transmission line under construction from NVE's Northwest 230 kV substation to Desert View to Pahrump, which is projected for completion in 2013. This line will provide a second 230 kV source into VEA's major system substation at Pahrump and form a looped 230 kV supply source. With this new 230 kV line in service, the VEA system will have four transmission tie lines with its neighboring systems, which are as follows:



- Amargosa-Sandy 138 kV tie line with WAPA;
- Jackass Flats-Lathrop Switch 138 kV tie line with Nevada Energy (NVE);
- Mead-Pahrump 230 kV tie with Western Area Power Administration (WAPA); and
- Northwest-Desert View 230 kV tie line with NVE.

2.9.2 Area-Specific Assumptions and System Conditions

The VEA area study was performed along with the SCE East of Lugo area study consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. The studies did not model the application of VEA's recently developed UVLS plan. In addition, specific assumptions and methodology that were applied to the Valley Electric Association area study are described below.

Transmission

In light of the FERC approved Transition Agreement between ISO and Valley Electric Association, the following major transmission projects are modeled in this planning cycles.

- VEA is planning a new 138 kV line from Charleston to Vista. This line will provide a looped supply source to the Charleston and Thousandaire substations, which comprise approximately one third of the VEA load and which are currently radially supplied from Gamebird 138 kV substation. Currently, this line is seeking construction permits and is planned to be in service in 2014.
- a new transmission interconnection tie between the VEA newly proposed 230 kV Bob Switchyard and the SCE new 220 kV Eldorado substation is planned by VEA and SCE and is assumed to be in service in 2015 or 2016.

After the VEA area study results were presented in the ISO TPP stakeholder meeting on September 26-27, 2012, an Amendment to Transition Agreement was approved by FERC on

October 15, 2012. This included a new Innovation-Mercury 138 kV transmission line and the Innovation 230/138-kV substation (formerly referred to as Stirling Mountain), which will be interconnected with the Desert View-Pahrump 230 kV line with projected in-service date of 2013. Therefore, this transmission project was not modeled in the pre-mitigation cases but was evaluated as mitigation in the post-mitigation cases to address the load flow concerns identified in the study.

Generation

There is no existing generation in the Valley Electric Association system. As described in section 2.3.2.5, two generation scenarios were studied for the area: 1) with the projected renewables; in which some potential renewable generation was modeled along with the transmission upgrades triggered by the renewables on the 2022 cases; 2) without the projected renewables; in which potential renewable generation was not modeled.

Load Forecast

The VEA Summer Peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses in the area. The VEA Summer Light Load and Spring Off-Peak base cases assume 27 percent and 57 percent of the 1-in-2 year heat wave load forecast, respectively.

Table 2.9-1 provides a summary of the VEA area loads modeled in the Valley Electric Association area assessment.

Table 2.9-1: Summer Peak load forecasts

Substation	2014	2017	2022
Valley Electric Association area (MW)	121	126	137

2.9.3 Assessment and Recommendations

The ISO conducted detailed planning assessment based on the study methodology identified in section 2.3 to comply with the Reliability Standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2013-2022 Summer Peak, summer light and Spring Off-Peak reliability assessments identified various reliability concerns that require mitigation in the current planning cycle. The ISO recommends the following mitigations to ensure secure power transfer and adequate load serving capability of the transmission system.

- prior to completion of the Innovation-Mercury Switch 138 kV Transmission Line and Innovation 230/138 kV Substation project, it is recommended to coordinate with NVE and request to operate the Northwest 138 kV bus voltage at about 1.03 pu under Summer Peak normal condition in 2013, to mitigate voltage deviation greater than 5 percent in both VEA and DOE areas under the Category B contingency of the Pahrump-Vista 138 kV line.

- prior to completion of the new Charleston-Vista 138 kV line, it is recommended to adopt an interim 8 percent voltage deviation criteria in 2013-2014 and work with WAPA to boost 138 kV bus voltage by re-setting No-Load Tap Changer (NLTC) of Amargosa 230/138 kV transformer to 0.975 pu from 1.025 pu on the 230 kV side to eliminate the low voltage less than 0.9 pu and voltage deviation as high as 13.3 percent on the Sandy, Gamebird, Thousandaire and Charleston 138 kV buses under Category B contingency of Pahrump-Gamebird 138 kV line.
- until the new 230 kV lines from Northwest to Desert View to Innovation to Pahrump are in service, an Operation Procedure is recommended only for light load condition to lock On-Load Tap Changer (OLTC) of the Pahrump 230/138 kV transformers to avoid any overvoltage condition in Desert View, Innovation, and Pahrump 230 kV substations under first contingency of Northwest-Desert View, Desert View-Innovation, or Mead-Pahrump 230 kV line is out of service.
- another operation procedure is recommended under first contingency of one of the two 230 kV transmission sources to properly operate the VEA 138 kV system in radial with three independent supplies from Jackass Flat, Amargosa, and the remaining 230 kV source in order to prepare second outage of remaining 230 kV transmission source.
- it is recommended to modify generation tripping SPS previously proposed in GIP in the VEA and SCE East of Lugo areas to eliminate the thermal overload, voltage concern, and power flow divergence triggered by the renewables generation in the both areas under various Category C contingencies (L-1-1). The SPS in the SCE Ivanpah area needs to be modified by the time the Bob Tap-Eldorado 230 kV transmission tie line is in service. The SPS previously proposed by the renewables in the Crazy Eye area needs to be reviewed or modified prior to completion of the generation.

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Chapter 3

3 Special Reliability Studies and Results

3.1 Overview

The special studies discussed in this chapter that have not been addressed elsewhere in the transmission plan. Within this planning cycle, four special studies have been conducted and are included within this chapter. The four special studies are: the Reliability Requirements for Resource Adequacy; Central California Study; Alternatives considered to the Coolwater-Lugo Project; and the Nuclear Generation Backup Plan Studies.

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 Section 40 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 2013.

3.2.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2012. A short-term analysis was conducted for the 2013 system configuration to determine the minimum local capacity requirements for the 2013 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 30, 2012. An addendum to this report was published on August 20, 2012 for the no SONGS conditions. A long-term analysis was also performed to identify local capacity needs in the 2017 period, and a report was published at the end of January 2013. 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 studies.

As shown in the LCT Report and indicated in the LCT Manual, 11 load pockets are located throughout the ISO-controlled grid as shown in 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 BAA 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
11	Valley Electric	VEA

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 the table below.

Table 3.2-2: Local capacity areas and requirements for 2013 and 2017

LCR Area	**Existing LCR Capacity Need (MW)**	
	2013	**2017**
Humboldt	190	165
North Coast and North Bay	629	446
Sierra	1,712	1,793
Greater Bay Area	413	404
Stockton	4,502	4,281
Greater Fresno	1,786	2,110
Kern	483	392
Los Angeles Basin	10,295	10,019
Big Creek/Ventura	2,241	2,537
San Diego	2,938	3,057
Valley Electric	0	0
Total	**25,189**	**25,204**

For more information about the LCR criteria, methodology and assumptions please refer to the ISO website. (A link is provided here).

For more information about the 2013 LCT study results, please refer to the reports posted on the ISO website. (Links are provided here and here).

For more information about the 2017 LCT study results, please refer to the report posted on the ISO website.

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 2013. These data can be found on the ISO website. (A link is provided here). The entire 2013 import allocation process is posted on the ISO website.

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 1,400 MW in year 2020 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 2022.

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. In addition, a concern has been identified regarding deliverability of existing MIC levels and the increase in MIC from the IID area due to potential overloads on the “West of the River” transmission path. Table 3.2-3 shows the ISO estimates of how the increase in MIC could 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>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><th>2022</th></tr>
<tr><td>IID-SCE_BG</td><td>471</td><td>471</td><td>471</td><td rowspan="2">471</td><td rowspan="2">471</td><td rowspan="2">471</td><td rowspan="2">1400</td><td rowspan="2">1400</td><td rowspan="2">1400</td><td rowspan="2">1400</td></tr>
<tr><td>IID-SDGE_BG</td><td>0</td><td>0</td><td>0</td></tr>
</table>

The 2019 increase is dependent on the in-service dates for:

- Path 42 upgrades to both the SCE as well as the IID system;
- West of Devers reconductoring project
- Address “West of the River” potential overload concerns

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 Central California Study

The transmission infrastructure in Central California not only serves the overall Fresno area but it is also an integral part of the bulk electric system that facilitates power transfers throughout the ISO-controlled grid. In addition, the Central California transmission system serves the interconnections with other jurisdictions within the Western Interconnection. With this, the performance of the system needs to be assessed under a variety of scenarios to ensure that the reliability requirements are met, as well as assessing potential policy or economic opportunities that may facilitate reliable delivery of the renewable energy to the ISO-controlled grid and the potential to allow for operation of flexible capacity to help integrate renewable energy.

The objective of this study was to evaluate the transmission system in Central California. The assessment comprised of monitoring the transmission facilities while stressing the system. The studies included, but were not limited to the following:

- North of Los Banos north-to-south transfer capability;
- Path 15 south-to-north transfer capability;
- Path 26 transfer capability;
- Fresno area import/export capability;
- San Joaquin area transmission reinforcement requirements;
- Fresno area local capacity requirements;
- economic analysis for congestion relief and renewable integration; and
- operational flexibility and potential economic benefit of HELMs (pump and generation).

The study evaluated potential alternative transmission developments in Central California to address reliability, policy and economically-driven needs identified in the assessment. A qualitative assessment of other benefits not addressed in the direct evaluation, among alternative transmission developments, were considered.

3.3.1 Study Area

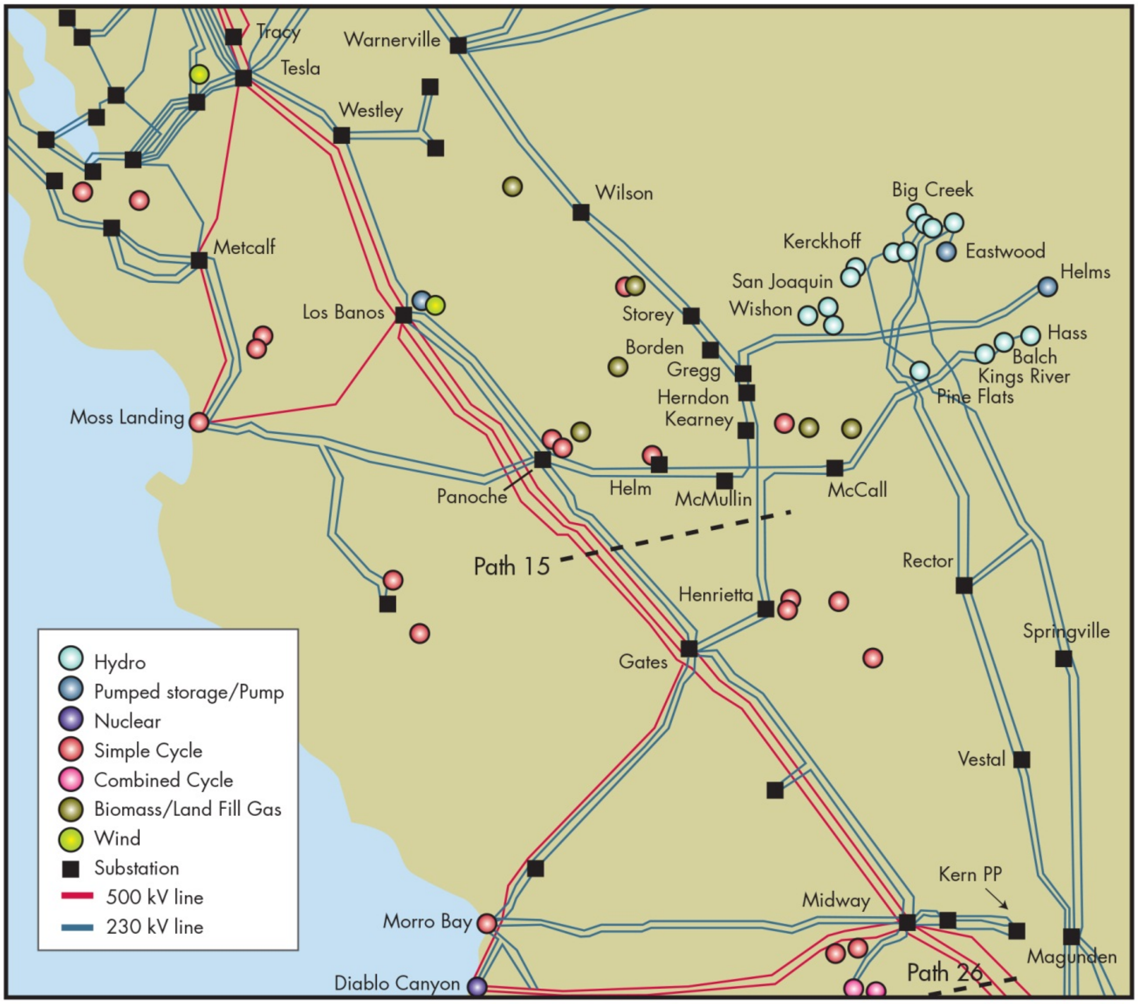
Figure 3.3.1 illustrates the bulk transmission system in California and the current interconnections to adjacent jurisdictions in the Western Interconnection. The primary study area for the Central California study was the 500 kV and 230 kV transmission system between Tesla and Midway substation as illustrated in the Figure 3.3-2. The major transmission in the area is as follows:

- WECC Path 15 (north of Midway);
- WECC Path 26 (south of Midway);
- 500 kV system North of Los Banos; and
- San Joaquin area 230 kV system.

Figure 3.3-1: Bulk transmission system

Note: Map does not represent line routings or right-of-ways

Figure 3.3-2: Central California study area



3.3.2 Study Assumptions

The assessment of flows path ratings, local area import and export capabilities as well as LCR, included analyzing system performance of the existing system and potential transmission alternatives as required, under post contingency conditions.

The study used the same assumptions and methodology as all other reliability assessments, unless noted below.

3.3.2.1 Study Years

Within the identified near and longer term study horizons, the ISO conducted detailed analysis on the years 2017 and 2022[14].

[14] Requirement R1.3.1 of TPL-001 and R1.3.2 of TPL-002, TPL-003 and TPL-004 states: *"Cover critical system conditions and study years as deemed appropriate by the responsible entity."*

3.3.2.2 Study Scenarios

The study scenarios simulated the critical system conditions[15] that stress the transmission system under a variety of loading and generation scenarios. Below provides the seasons assessed in each study year.

Table 3.3-1: Summary of study scenarios

Study Area	2017	2022
Central California Study	Summer Peak Fall/Winter Summer Partial Peak Spring Light Load	Summer Peak Fall/Winter Summer Partial Peak Spring Light Load

The following provides a description of the system conditions assessed for each scenario identified in the table above.

Summer peak base case

- To evaluate the impact on North of Los Banos north-to-south transfer capability with low hydro conditions in the Fresno area; and
- To quantify the "difference" in Fresno area LCR with and without any potential alternatives to be assessed to address the performance requirements identified in the assessment.

Fall-winter base case

- To evaluate the impact on Path 15 south-to-north transfer capability and will represent low hydro conditions at this time of the year.

Summer partial peak base case

- To evaluate the import capability of Fresno area under low hydro conditions during partial peak periods at about 8:00 p.m. (when transmission re-rates are not in effect per the participating transmission owner facility ratings).

Spring off-peak load base case

- To evaluate the export capability of Fresno area during high resource output (hydro, QF, solar) at about 8:00 a.m. in low load conditions.

3.3.2.3 Sensitivity Analysis

Sensitivity cases include the generation dispatched in the study cases based upon varying operating conditions that the generation operates on the system and flows that occur on the major paths. These include the following:

[15] Requirement R1.3.1 of TPL-001 and R1.3.2 of TPL-002, TPL-003 and TPL-004

- Output of the variable generation that is not dispatchable (i.e., wind and solar) was assessed under anticipated conditions in the case as well as at or near capacity and at zero MW output.
- The hydro dispatch in the study area and northern California will impact the flows on the major paths and therefore a sensitivity of high hydro and low hydro conditions was assessed.

A sensitivity analysis has been performed to study the operational flexibility of the HELMs Pump Storage Power Plant.

3.3.2.4 Reliability Standards and Criteria

The North American Electricity Council (NERC) Reliability Standards, Western Electricity Coordinating Council (WECC) Regional Criteria and the ISO Grid Planning Standards have been applied to the studies consistent with section 2.2 of this plan.

3.3.2.5 Contingencies

The contingencies that produce the more severe system results and impacts[16] have been selected to assess the Central California transmission system performance consistent with the approach noted in section 2.3.2.4.

3.3.2.6 Base Cases

The power flow base cases from WECC were used as the starting point for the base cases, which were consistent with the cases used for the studies in Section 2. The PG&E cases identified in Table 3.3-1 for the applicable year and season have been used. With the addition of the spring light load condition identified for the Central California study and not planned to be studied in the 2012-2013 Transmission Plan, the WECC case to be used for these scenarios were selected from the WECC base cases as appropriate and will be documented in the study assessment.

3.3.2.7 Demand Forecast

The assessment used the California Energy Demand Forecast 2012-2022 revised mid-case released by California Energy Commission (CEC) dated February 2012, which is consistent with section 2.3.2.7 of this plan.

The 1-in-5 load forecast has been used for studies consistent with the bulk transmission system studies and policy-driven analysis conducted in the reliability and policy assessments set out in:

- bulk transmission system studies in chapter 2; and
- policy-driven analysis in chapter 4.

The 1-in-10 load forecast has been used for studies consistent with the local system assessments and local capacity studies conducted in keeping with the 2012-2013 Study Plan and set out in:

[16] Requirement R1.3.1 of TPL-002, TPL-003 and TPL-004

- local transmission system assessment in Fresno in section 2.5.6; and
- local capacity studies for Fresno area in section 3.1.

3.3.2.8 Generator Assumptions

The base cases developed for the study years applied the generation assumptions identified in section 2.3.2.5 of chapter 2.

In the near-term assessment cases, which includes study year 2017, the generation additions and retirements will be modeled in the base cases consistent with the requirements found in section 2.3.2.5 and as identified under the 2-5 year planning cases.

In the longer term assessment cases, which includes study year 2022, the conventional generation additions and retirements were modeled in the base cases consistent with the requirements identified in section 4. The renewable generation will be modeled in the cases utilize the renewable portfolios developed in 2012 by CPUC and CEC to meet the 33 per cent RPS requirement as per section 4.

3.3.2.9 Transmission Assumptions

The transmission system projects modeled are consistent with approach discussed in section 2.3.2.6. In addition, the reactive resources, protection systems and control devices have been modeled consistently with sections 2.3.2.8, 2.3.2.11 and 2.3.2.12.

3.3.2.10 Study Methodology

The assessment for Central California applied the study methodology consistent with Section 2.3 for the other technical studies conducted in the planning cycle.

The studies have been conducted using GE PSLF as the main study tool. The approach will be consistent with the bulk assessment of the 2012-2013 Transmission Plan with the governor power flow and transient stability analysis to be used to evaluate system performance following the contingencies of equipment at voltages 230 kV and higher.

3.3.2.11 HELMs Water Availability Assessment

The HELMs Pumped Storage Plant (HELMs) is an important generation resource used to supply summer peak loads in the Greater Fresno Area (GFA). To serve peak loads, the facility must be able to pump sufficient water during the partial and off-peak periods from its lower reservoir (Wishon reservoir) to its upper reservoir (Courtright reservoir).

The Water Analysis Model tracks the ability of HELMs to pump and generate given specific load levels and transmission configurations. A description of the functionality of the Water Analysis Model is provided in Appendix D. The HELMs operating and hydro data was supplied by PG&E. Equations were developed to forecast transmissions loading to predict pumping constraints and generating requirements. The latest estimates of forecasted summer peak loads for the Greater Fresno Area, consistent with the CEC's peak load forecasts with a small positive adjustment to reflect the impact of dry hydro (1 in 5) on peak loads in the Central California area were used. Generation data has also been included that is consistent with the power flow cases for 2022 as well as the CPUC resource portfolios. The existing Fresno Area transmission plus already approved upgrades were assumed.

The generation equations predict how HELMs generation would be constrained (i.e. pumping in partial or off peak periods is limited by loadings on WW in normal, N-1 and G-1 conditions). The Water Analysis Model conservatively dispatches HELMs to only mitigate the overloads on the limiting transmission element. Once the need for generation is established, the Water Analysis Model determines if sufficient water can be pumped into the Courtright reservoir to deliver that power. The pumping equations estimate WW line flows assuming all lines in service, and 1, 2 or 3 pumps are in operation. The Water Analysis Model applies these pumping equations to each hour of the summer period and assumes maximum pumping occurs in all hours where 1, 2, or 3 pumps can run without exceeding the WW line rating. The results of the HELMs water analysis are very sensitive to both the installed PV level in the GFA and the combustion turbine (peaker) use in the GFA.

3.3.3 Assessment

3.3.3.1 Technical Assessment

The technical assessment was undertaken apply the consistent approach as the reliability assessment in chapter 2 with the study assumptions identified above in section 3.3.2 above. Within the technical studies, the low and hydro years conditions were used to determine the critical system conditions that the system should be planned for. Table 3.3-2 illustrates the load and generation assumptions for the Fresno area in the study scenarios established in section 3.3.2. The analysis was conducted for 2017 and 2022.

Table 3.3-2: Base case assumptions

	Summer Peak	Summer Partial Peak	Spring Off-Peak	Fall/Winter Off-Peak
Hydro Condition	Dry	Dry	Wet	Dry
Fresno/Yosemite Demand	3,468	3,086	1,240	1,278
HELMs	1,200	Off-line	1,200	-620
Hydro (SJR, KR, MR)	574	419	449	20
PEC	381	381	Off-line	Off-line
Renewables (PV)	1,432	Off-line	567	626
Peakers	522	16	Off-line	Off-line
Other area generation	305	305	168	168
Path 15 (N-S)	596	-60	-3,373	-5,398
Path 26 (N-S)	1,851	703	-340	-1,921

TPL 001: System Performance under Normal Conditions

Two PG&E facilities were overloaded under partial peak load conditions in the 2017 and 2022 case, the 230 kV transmission lines in Bellota-Warnerville and Warnerville-Wilson.

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

In the 2017 and 2022 Partial Peak case, the same two transmission lines that were overloaded under normal conditions were also overloaded with Category B contingencies; their loading increased with some contingencies.

Under off-peak load conditions, there was one Category B overload identified.

No facilities were identified with voltage concerns under the Category B performance requirement in any of the cases studied.

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

For the 2017 and 2022 summer partial peak case, the same facilities that may overload under normal conditions and with Category B contingencies may also overload with Category C contingencies. In addition to these facilities, in 2022 there were numerous other transmission facilities that may overload under partial peak conditions.

Voltage collapse was observed for Category C contingency of the Gates-Gregg and Gates-McCall 230 kV transmission lines.

For the summer off-peak and light load cases, in 2017 two facilities were identified with thermal overloads and in 2022 numerous facilities were identified with thermal overloads. No facilities were identified with voltage concerns under the Category C performance requirement. The system remained stable following these contingencies; however, there were the same transient voltage and frequency violations that were observed with Category B contingencies.

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

Table 3.3-3 illustrates the overloaded facilities that were observed with varying HELMs pumps operating.

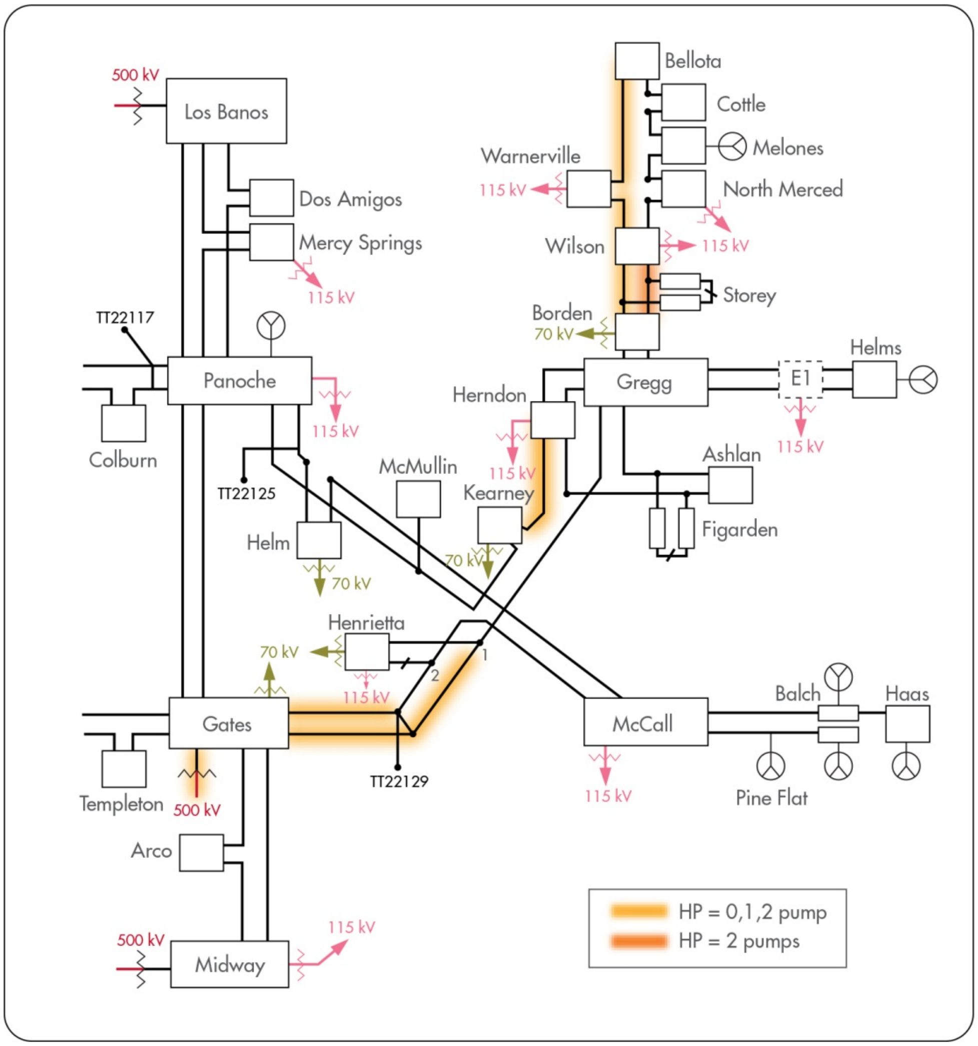
Table 3.3-3: 2022 Partial Peak overloaded facilities with 0, 1 or 2 HELMs pumps

Overloaded Facility	**HELMs Pumps**		
	0	**1**	**2**
Gates 500/230 kV TB	112%	114%	122%
Bellota – Borden 230 kV	B-W[17] (101%) W-W (168%) W-S1 (105%) S1-B (110%)	B-W (117%) W-W (185%) W-S1 (104%) S1-B (109%)	B-W (109%) W-W (183%) S1-W (113%) S1-B (121%) W-S2 (108%)
Kearney – Herndon 230 kV	21%	21%	149%
Gates – Henrietta 230 kV	G-127 (106%) G-128 (102%) HT-128 (120%)	G-127 (107%) G-128 (102%) HT-128 (120%)	G-127 (108%) G-128 (104%) HT-128 (122%)
Panoche – Kearney 230 kV			P-123 (111%)
Westley – Los Banos 230 kV			W- 015 (101%)

[17] Represents the segment of the overloaded facility identified. For example for Bellota – Borden 230 kV line B-W indicates the overloaded line segment from Bellota to Warnerville.

The figure below illustrates the facilities in 2022 that were overloaded under the Partial Peak assessment in the Central California/Fresno area.

Figure 3.3-3: Central California/Fresno 230 kV system with overloads in 2022 Partial Peak



The table below illustrates the facilities in 2022 that were overloaded under the Summer Peak, Spring and Fall/Winter Off-Peak assessment in the Central California/Fresno area.

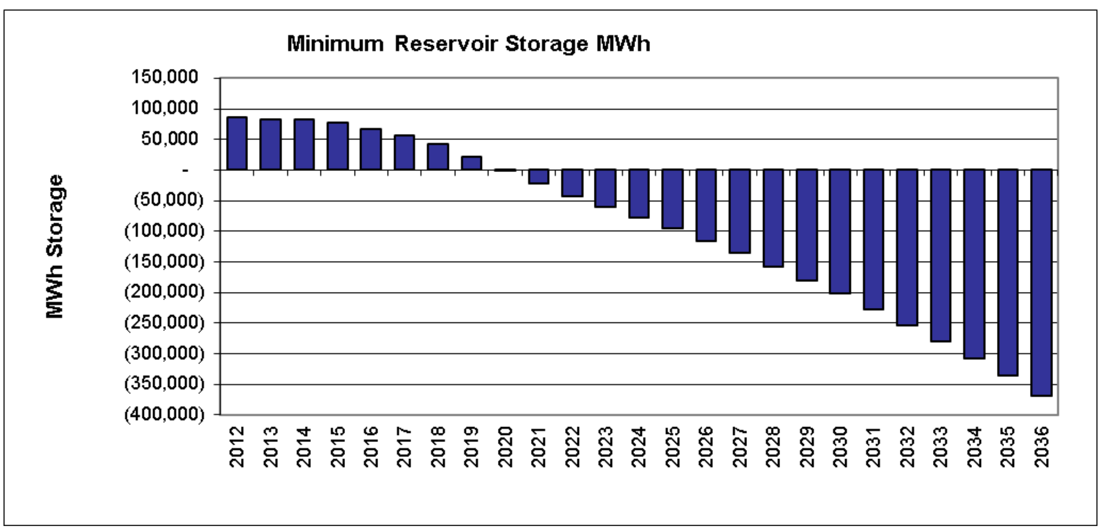
Table 3.3-4: Summer Peak, Spring and Fall/Winter Off-Peak overloaded facilities in 2022

Impacted Facility	Summer Peak	Spring Off Peak	Fall / Winter Off Peak
Bellota – Borden 230 kV		W-W (116%) W-S1 (104%) S1-B (121%)	
Westley – Los Banos 230 kV		W-105 (127%) 105-LB (120%)	W-105 (134%) 105 – LB (127%)
Gates -- Midway 230 kV			A-M (105%) G-M (123%)

3.3.3.2 Water Availability Assessment

Utilizing the water model that was developed the availability of water to be able to generate when needed based upon the available time that can be used for pumping to refill the reservoir was assessed. The analysis was conducted under the lower water scenario. Figure 3.3-4 illustrates that by 2020 there would not be adequate water to satisfy the reliability needs of the HELMs generation due to the system limitations to be able to pump enough water at HELMs for storage.

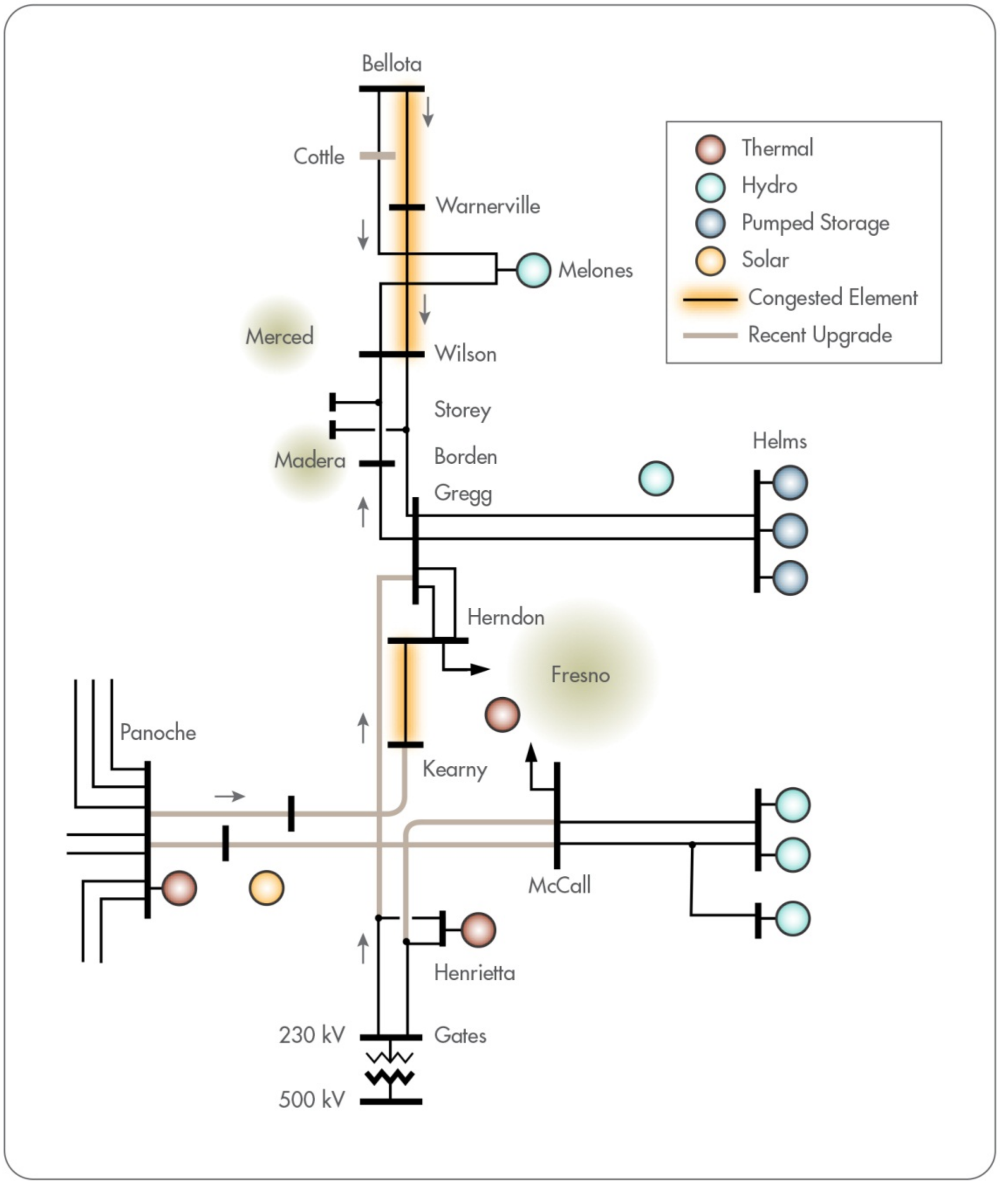
Figure 3.3-4 HELMs reservoir capability for summer operation



3.3.3.3 Congestion Assessment

Congestion analysis was conducted consistent as a part of the Central California study consistent with the approach and methodology in chapter 5. The figure below illustrates the congestion that was observed on the transmission lines in the Central California/Fresno area in 2017.

Figure 3.3-5 Central California/Fresno area congestion



3.3.4 Development of Mitigation Plans

In developing the mitigation plans for the identified reliability concerns identified in section 3.3.1 no one single development was sufficient. In other words, the development of only a new transmission line, reconductoring of existing transmission lines or addition of transformer at a station by itself failed to address the identified reliability concerns. With this, a comprehensive development plan was assessed by incrementally increasing the development components to build the mitigation plan to address the concerns.

Table 3.3-5 Alternative configurations assessed as mitigation plans

Configuration	Description of Configuration
0	Base Case (No Upgrades)
1a/1b/1c	a) 50.5 Ohm Series Reactor at Wilson on W-W 230 kV Line; b) Reconductor overloaded Bellota-Gregg lines (136 mi); or c) Warnerville loop and 2-25 ohm reactors at Wilson
2	Configuration 1 plus: - 1122 MVA Gates 500/230/13.8 kV Transformer Bank Addition
3x	Configuration 2 plus: - Northern Fresno Area Reinforcements including North Fresno Substation (plus 200 MVAR SVD)[1]
4	Configuration 3 plus: a) one Gates-Gregg 230 kV Line; b) one Panoche-Gregg 230 kV Line; or c) one Los Banos-Gregg 230 kV Line
5	Configuration 4 plus: - one Gates-North Fresno 230 kV Line
6	Configuration 4 plus: - Raisin City Junction Switching Station with looping of all existing and planned 230 kV transmission (6 circuits total) in the vicinity of RCJ and SVC (plus 200 MVAR SVD

Note 1: The Northern Fresno Area Reinforcement project has been recommended for approval in Section 2.5.6.

3.3.4.1 Mitigation Plan - Technical Assessment

In configurations 1 and 4 three different alternatives were assessed for each configuration.

For configuration 1, the performance of 1a) 50.5 Ohm Series Reactor at Wilson on Wilson-Warnerville 230 kV Line and 1b) reconductoring of Bellota-Gregg 230 kV lines were similar while the performance of 1c) Looping of stations into Warnerville 230 kV line and 2-25 ohm reactors at Wilson did not fully address the overloads on the on the Bellota-Gregg 230 kV lines and was not considered further. With the performance of configurations 1a) and 1b) be being similar, the cost of each alternative was considered to determine the preferred configuration. The estimated cost to install a 50 ohm reactor in configure 1a) was $20 to 30 million as compared to reconducting approximately 136 miles of 230 kV line which was estimated to cost between $150 to $200 million. Based on this the preferred alternative for configuration 1 was the installation of a 50 Ohm reactor and has been included in the analysis below.

For configuration 4, the performance of 4a) one Gates-Gregg 230 kV Line, 4b) one Panoche-Gregg 230 kV Line; or 4c) one Los Banos-Gregg 230 kV Line were assessed. From the technical performance the three alternatives performed similarly. Further analysis was undertaken in Chapter 5 comparing the economic performance of the three alternatives with the 4a) Gates-Gregg 230 kV line having a sight advantage, particularly over 4b) Los Banos-Gregg 230 kV line largely due to the increase in the length of line between the alternatives respectively. Based on this the preferred alternative for configuration 4 was the Gates to Gregg 230 kV line and has been included in the analysis below.

Table 3.3-6 provides the performance of the development configurations to mitigate for the identified overloaded facilities under Summer Partial Peak conditions. As can be seen in the table the Kearney to Herndon 230 kV line remains overloaded for all configurations. With this, in addition to the identified configurations, the Kearney to Herndon 230 kV line would need to be reconductored. The Kerney to Herndon 230 kV line is approximately 10 miles in length.

Table 3.3-6: Summer Partial Peak performance of development configurations with 2 HELMs pumps

Impacted Facility	Conf. 0 No Upgrades	Conf. 1	Conf 2	Conf 3	Conf. 4	Conf. 5	Conf. 6
Gates 500/230 kV TB	122%	129%					
Bellota – Gregg 230 kV	B-W (109%) W-W (183%) S1-W (113%) S1-B (121%) W-S2 (108%)	B-C (106%) NM-M (107%) W-W (101%)	B-C (102%) NM-M (103%)	B-C (102%) NM-M (102%)			
Kearney – Herndon 230 kV	149%	164%	163%	160%	122%	104%	103%
Gates – Henrietta 230 kV	G-127 (108%) G-128 (104%) HT-128 (122%)	G-127 (116%) G-128 (111%) HT-128 (133%)	G-127 (120%) G-128 (115%) HT-128 (136%)	G-127 (120%) G-128 (115%) HT-128 (131%)	G-128 (102%) HT-128 (103%)		HT-128 (107%)
Panoche -- Kearney 230 kV	P-123 (111%)	P-123 (122%)	P-123 (117%)	P-123 (115%)			
Voltage Instability at Kearney 230 kV	observed	observed	observed	observed			
Westley-Los Banos 230 kV *	W- 015 (101%)	W- 015 (113%) 015- LB (113%)	W- 015 (111%) 015- LB (111%)	W- 015 (112%) 015- LB (111%)	W- 015 (111%) 015- LB (110%)	W- 015 (111%) 015- LB (110%)	W- 015 (111%) 015- LB (111%)

The overloads on Westley to Los Banos 230 kV and Gates -- Midway 230 kV in the Partial Peak, Spring and Fall/Winter Off-Peak identified is not predominantly a function of the HELMs pumping or area loading and relates to the flows on Path 15 and Path 26. Mitigation of these overloads can be addressed through congestion management on the paths and will be assessed further in future planning cycles.

The table below illustrates the performance of the development configurations to mitigate the overloads during the Spring Off-Peak conditions.

Table 3.3-7: Spring Off-peak performance of development configurations

Impacted Facility	Conf. 0 No Upgrades	Conf. 1 React	Conf 2 Gates Bk	Conf 3x No Fr	Conf. 4 G-G line	Conf. 5 G-NoFr	Conf. 6 RCJ
Bellota – Gregg 230 kV	W-W (116%) W-S1 (104%) S1-B (121%)	S1-B (108%)	S1-B (107%)				
Westley-Los Banos 230 kV *	W-105 (127%) 05--LB (120%)	W-105 (133%) 15--LB (126%)	W-105 (133%) 05--LB (126%)	W-105 (134%) 05--LB (127%)	W-105 (134%) 05--LB (127%)	W-105 (134%) 05--LB (134%)	W-105 (135%) 05--LB (128%)

The table below illustrates the performance of the development configurations to mitigate the overloads during the Fall/Winter Off-Peak conditions.

Table 3.3-8: Fall/Winter Off-peak performance of development configurations with 2 HELMs pumps

Impacted Facility	Conf. 0 No Upgrades	Conf. 1 React	Conf 2 Gates Bk	Conf 3x No Fr	Conf. 4 G-G line	Conf. 5 G-NoFr	Conf. 6 RCJ
Panoche – Gates 230 kV *	P-G1 (106%) P-G2 (106%)	P-G1 (108%) P-G2 (108%)	P-G1 (112%) P-G2 (112%)	P-G1 (106%) P-G2 (106%)			
Westley – Los Banos 230 kV *	W-105 (118%) 105–LB(110%)	W-105 (117%) 105–LB(110%)	W-105 (118%) 105–LB(110%)	W-105 (117%) 105–LB(110%)	W-105 (116%) 105–LB(109%)	W-105 (116%) 105–LB(109%)	W-105 (117%) 105–LB(110%)
Gates -- Midway 230 kV *	G-A (108%) A-M (105%) G-M (123%)	G-A (107%) A-M (105%) G-M (123%)	G-A (108%) A-M (105%) G-M (123%)	G-A (108%) A-M (105%) G-M (123%)	G-A (109%) A-M (106%) G-M (124%)	G-A (109%) A-M (106%) G-M (124%)	G-A (110%) A-M (107%) G-M (125%)

3.3.4.2 Mitigation Plan - Water Availability Assessment

Similar to the water availability assessment of the existing system that was illustrated was conducted for section 3.2.3.2 was conducted for development configurations 3 and 4. The assessment utilizes similar water usage as historical operation of HELMs and does not reflect additional utilization that may be required for renewable integration and flexibility requirements.

Figure 3.3-6 shows that by 2029 there would not be adequate water to satisfy the reliability needs of the HELMs generation due to the system limitations to be able to pump enough water at HELMs for storage with development configuration 3. The decline in the availability of water starts to occur in the 2023 timeframe.

Figure 3.3-6: Water availability to be able to generate to meet reliability need
Development Configuration 3

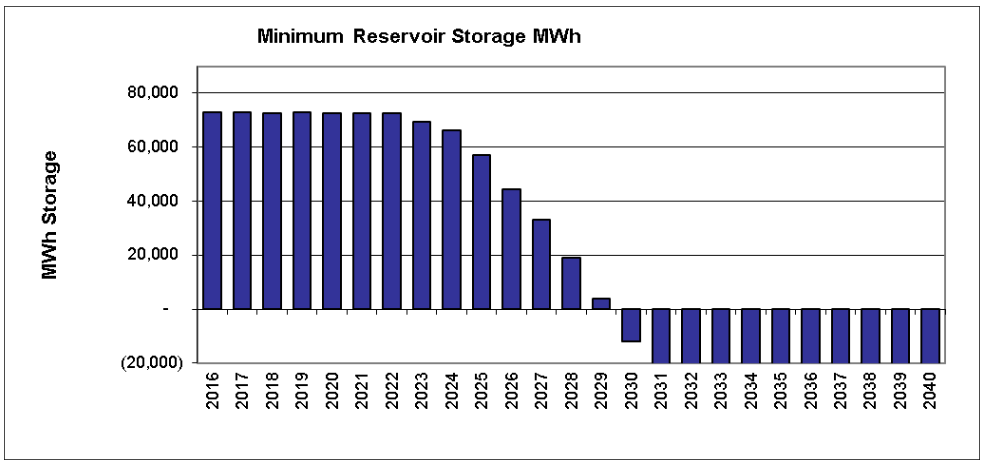
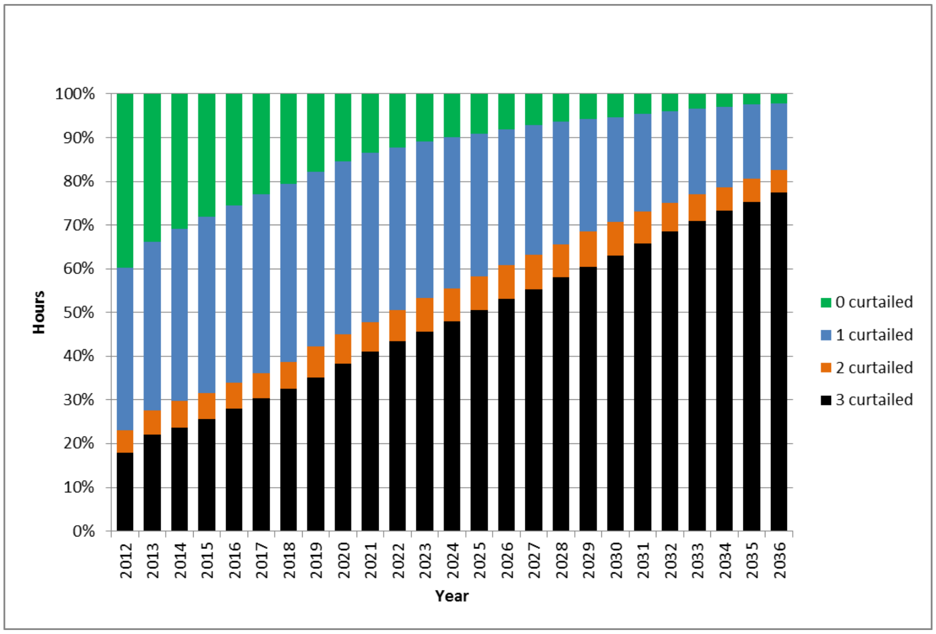


Figure 3.3-7 illustrates the percentage of times by year where there would be constraints that would limit the number of pumps that would able to operate simultaneously with development configuration 3. While the pumping limitations would not impact the ability to provide adequate windows for generation operation to maintain area reliability, it does illustrate that there would be significant times when the pumps would be constrained or not available to provide ancillary services or flexible operation for renewable integration.

Figure 3.3-7: Water availability to be able to generate to meet reliability need
Development Configuration 3



The figure below shows that by there would be adequate water to satisfy the reliability needs of the HELMs generation for development configuration 4

Figure 3.3-8: Water availability to be able to generate to meet reliability need
Development Configuration 4

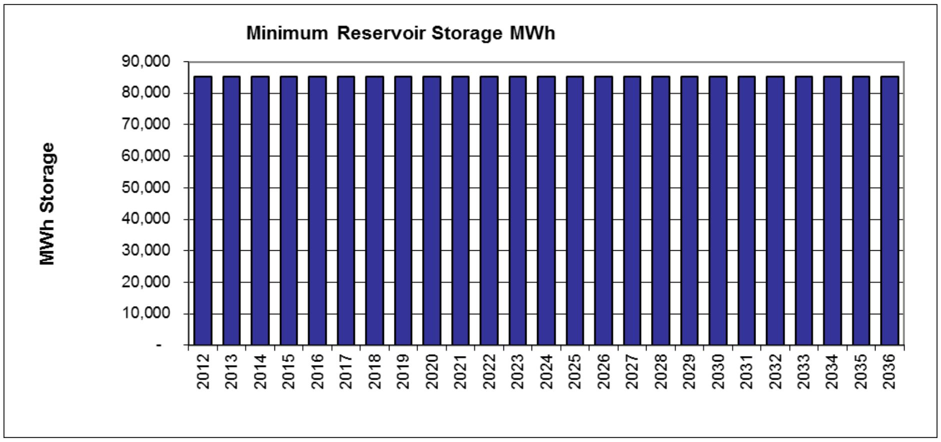
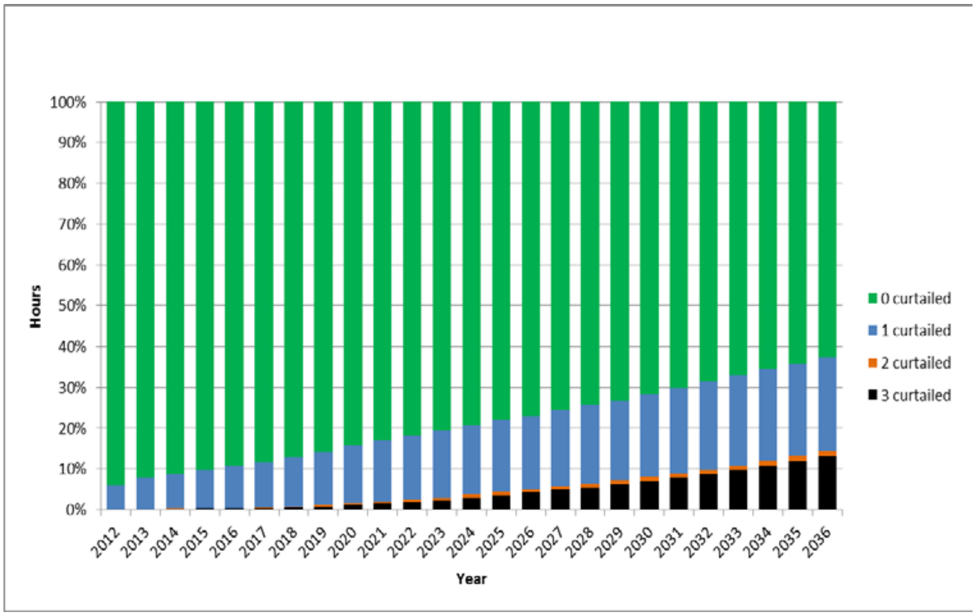


Figure 3.3-9 illustrates the percentage of times by year where there would be constraints that would limit the number of pumps that would able to operate simultaneously with development configuration 4. With this, there would be very limited time with this development configuration where there would be limitations on the ability for HELMs to pump. As indicated above this would not be required in the near term for reliability requirements; however would provide significant opportunities for the HELMs pump storage facility to provide ancillary services and flexible operation for renewable integration.

Figure 3.3-9: Water Availability to be able to generate to meet reliability need
Development Configuration 4



3.3.5 Recommended Mitigation Plan

To address the reliability requirements to mitigate the identified overload, voltage stability and water management for generation capability in the area development configuration 3 would provide adequate performance; however will be inadequate in future years. In addition the development configuration 3 would still have significant periods when the availability of pumping would be limited and not available for ancillary service or provide flexibility for renewable integration needs that are currently being determined. With this the development configuration 4 is recommended. As seen in section 3.2.4.1, in addition to all of the development configurations the Kearney to Hearndon 230 kV line reconductoring would be required.

Table 3.3-9 identifies the recommended components of the mitigation plan to address the reliability needs of the Central California/Fresno area, the pumping requirements of HELMs for area reliability and provide flexibility for the HELMs Pump Storage facility to provide ancillary services and renewable integration requirements.

Table 3.3-9: Recommended mitigation plan

Project	Estimated In-Service Date	Estimated Cost
Series Reactor on Warnerville-Wilson 230 kV Line	2017	$20-30 million
Gates #2 500/230 kV Transformer Addition	2017	$75-85 million
Kearney - Hearndon 230 kV Line Reconductoring	2017	$15-25 million
Gates-Gregg 230 kV Line	2022(1)	$115-145 million

Note (1): The water analysis identified the need for the Gates-Gregg 230 kV line in the 2023-2025 timeframe as indicated. The ISO notes that an earlier in-service date can be rationalized due to the benefits the project provides, but the 2022 date was based on the expectations of the incumbent PTO regarding timing. This can be explored in more detail in the competitive solicitation process. An earlier date will be sought if viable.

It is recommended that the Gates-Gregg 230 kV Line be constructed as a double circuit 230 kV line with one side strung. This will facilitate future development requirements to supply load or integrate renewable generation in the area while minimizing the future right of way requirements compared to single circuit development. In addition, it would be preferable to route the Gates-Gregg 230 kV line in the vicinity of the area identified as Raison City junction to allow for the potential development of a switching station to interconnect this line with the existing 230 kV lines in the area. This would provide for long-term planning for the area to facilitate the development of configurations 5 and 6 identified in section 3.2.4 in the future when required.

3.4 Alternatives considered to the Coolwater-Lugo Project: AV Clearview Transmission Project

The Coolwater-Lugo 230 kV transmission line was triggered by an LGIA with ISO generation project #125 in the serial group, executed in 2010. The Coolwater-Lugo 230 kV transmission line was identified in the LGIA as a delivery network upgrade needed to mitigate the overloads on the Kramer-Lugo #1 & #2 230 kV Lines.

SCE's application to the CPUC for a Certificate of Public Convenience and Necessity (CPCN), for the Coolwater-Lugo project is expected in 2013. In anticipation of that filing, the CPUC has indicated that alternatives to Coolwater-Lugo supporting west Mohave renewable generation will need to be considered in the upcoming CPCN proceedings. The AV Clearview Transmission Project was suggested in comments submitted during the planning process as an alternative to the Coolwater-Lugo 230 kV transmission line. Thus, in light of the of the CPUC's stated need to meaningfully discuss alternatives in the CPCN process, the ISO decided to study AV Clearview as an alternative in preparation for the CPCN proceeding. Conducting this analysis as part of the transmission planning process provides a consistent study framework for the analysis and greater transparency to stakeholders about an alternative that might be considered in the CPCN proceeding.

The Coolwater-Lugo 230 kV transmission project consists of the following transmission elements:

- Coolwater-Lugo 220kV Transmission Line:
    - Install a new 59 mile 220kV transmission line including the following elements:
        - approximately 16 circuit miles of 2B-2156 KCMIL ACSR conductor
        - approximately 43 circuit miles of 2B-1590KCMIL ACSR conductor
        - ½ inch steel overhead ground wire as needed
        - approximately 59 miles of OPGW (315,000 linear feet)
- Coolwater Generating Station 220kV Switchyard:
    - Install necessary equipment to terminate the new Lugo 220kV transmission line in a breaker-and-a-half configuration.
- Lugo Substation:
    - Install the necessary equipment to terminate the Coolwater 220kV transmission line in a new double breaker line position arranged in a breaker-and-a-half configuration.

North of Lugo Area Description

The Coolwater-Lugo 230 kV transmission line and the AV Clearview Transmission Project alternative are located in the North of Lugo transmission system. The North of Lugo transmission system serves San Bernardino, Kern, Inyo and Mono counties. The area extends more than 270 miles north from Lugo.

The North of Lugo electric transmission system is composed of 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has interties with LADWP and Sierra Pacific Power. In the south, it connects to the Eldorado substation through the Eldorado-Baker-Cool Water–Dunnside-Mountain Pass 115 kV line. It also connects to the Pisgah substation through the Lugo-Pisgah #1 and #2 230 kV lines. Two 500 and 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.

The ISO studied the North of Lugo area under four renewable development scenarios. Table 3.4-1 shows the relevant renewable generation amounts in each of those scenarios. More information about the renewable scenarios and the North of Lugo area studies are in Chapter 4. This section describes the alternative mitigation that was considered to mitigate identified transmission deficiencies.

Table 3.4-1 Renewable generation in the SCE system modeled to meet the 33 percent RPS net short

Zone	**High DG (MW)**	**Environmentally Constrained (MW)**	**Commercial Interest (MW)**	**Cost Constrained (MW)**
Kramer	62	64	765	62
DG	95	2	0	2
San Bernardino – Lucerne	187	108	106	271

3.4.1 Overview of AV Clearview Transmission Project Alternative

The High Desert Power Authority suggested that the AV Clearview Transmission Project could serve as an alternative to the Coolwater-Lugo 230 kV Transmission Project. The stated purpose of the facility is to connect eastern transmission and resources around the Kramer/Coolwater area to the Tehachapi area. Upon request, High Desert Power Authority provided the ISO with additional information to the ISO; namely, more details about two options, which include a Baseline Case and an Expanded Case.

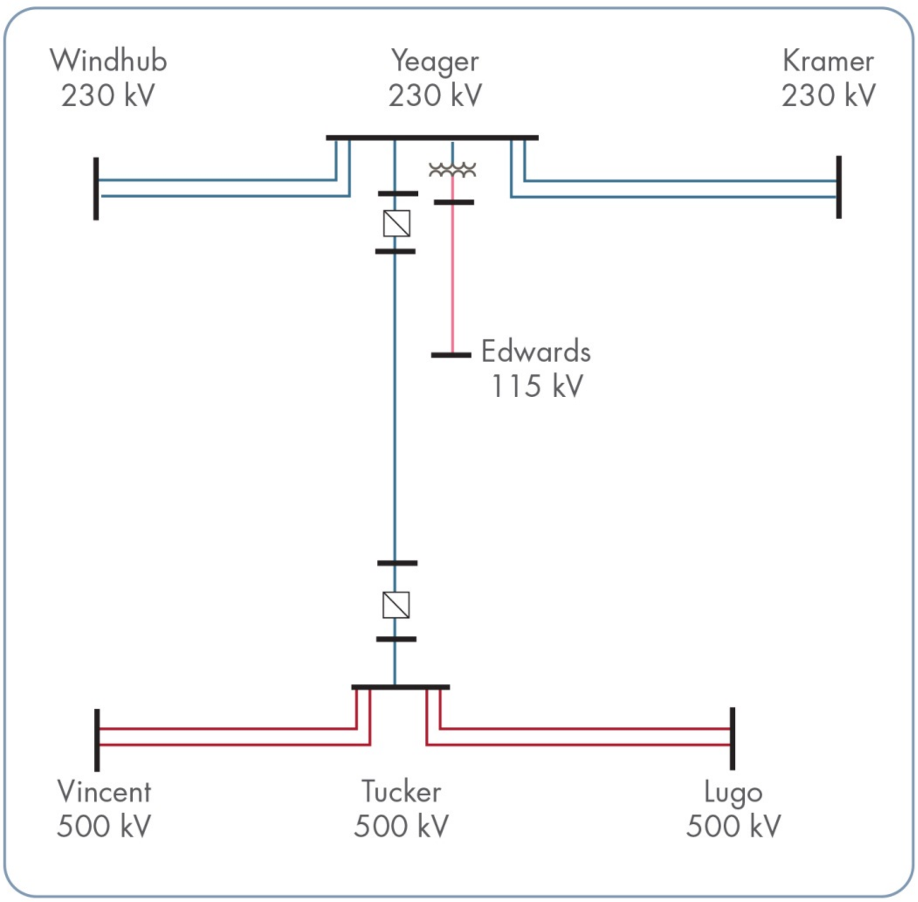
The Baseline Case consists of the following transmission elements:

- new 230 kV Yeager Substation;
- new double circuit 230 kV from Windhub to Yeager;
- new double circuit 230 kV from Yeager to Kramer;

- new 230/115kV step down transformer bank at Yeager;
- new single circuit 115kV from Yeager to SCE Edwards 115 kV substation;
- new 500 kV Tucker Substation;
- new 1000 MW capacity underground DC line between Yeager and Tucker Substations; and
- loop Lugo-Vincent #1 and #2 Lines through Tucker Substation.

The figure below shows the Baseline Case configuration.

Figure 3.4-1: AV Clearview alternative: baseline case configuration

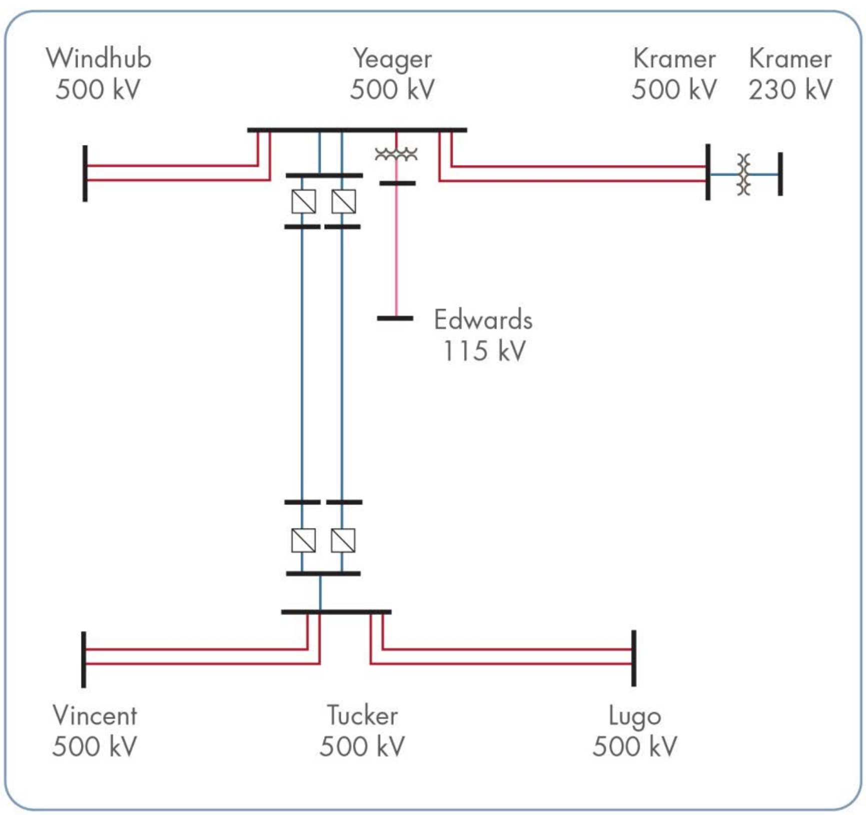


The Expanded Case consists of the following transmission elements:

- new 500 kV Yeager Substation;
- new double circuit 500 kV from Windhub to Yeager;
- new double circuit 500 kV from Yeager to Kramer;
- new 500/115kV step down transformer bank at Yeager;
- new single circuit 115kV from Yeager to SCE Edwards 115 kV substation;
- new 500 kV Tucker Substation;
- new 2000 MW capacity underground DC line between Yeager and Tucker Substation; and
- loop Lugo-Vincent #1 and #2 Lines through Tucker Substation.

The figure below shows the expanded case configuration.

Figure 3.4-2: AV Clearview alternative: expanded case configuration



It should be noted that the Expanded Case has been identified as a separate alternative, not as a future expansion to the Baseline Case, referencing in particular the 230 kV construction in the Yeager area. The costs set out below have similarly been provided on a “two alternative” basis.

The figure below shows the geographical location of the AV Clearview Transmission Project alternative.

Figure 3.4-3: AV Clearview alternative: geographical map

3.4.2 Cost Comparison of AV Clearview Transmission Project Alternative and Coolwater-Lugo 203 kV Transmission Line

Table 3.4-2 shows the cost estimates of the three projects. The cost estimate for the Coolwater-Lugo project was provided by SCE, and the cost estimates for the two AV Clearview alternatives were provided by the High Desert Power Authority. The ISO has taken each cost estimate at face value. Because the ISO conducted this study for the purposes of providing information to the upcoming CPUC proceeding, the ISO expects that the cost estimates will be considered at that time.

Table 3.4-2 Cost estimates of AV Clearview Transmission Project Alternative and Coolwater-Lugo 203 kV Transmission Project

Project	Estimated Cost
AV Clearview Transmission Project Alternative – Baseline Case	$670 million
AV Clearview Transmission Project Alternative – Expanded Case	$1,190 million
Coolwater-Lugo 230 kV Transmission Project *(Note 1)*	$436 million

Note 1: The cost presented here does not include the following elements that were originally included in the scope of work for the South of Kramer Transmission Project which included the Coolwater-Lugo 230 kV line: (1) Lugo 500/230 kV #3 transformer (this transformer is not needed for the portfolio scenarios studied) and (2) Jasper Substation.

3.4.3 Policy-Driven Powerflow and Stability Study Results

Chapter 4 of this report describes the study assumptions and study methodology of the policy-driven powerflow and stability study analysis performed by the ISO. Using the assumptions and study methodology described therein, the AV Clearview Transmission Project alternative was found to be a potential mitigation for the following constraints that were identified in the policy-driven powerflow study for the SCE area.

- Commercial Interest portfolio — peak scenario: case divergence following an N-2 contingency of Kramer-Lugo 230 kV lines
- Commercial Interest portfolio — off-peak scenario: case divergence following an N-2 contingency of Kramer-Lugo 230 kV lines

As described in chapter 4, both the Coolwater-Lugo 230 kV Transmission Line and the AV Clearview Transmission Project alternative were found to be effective at mitigating the above constraints.

3.4.4 Deliverability Assessment Results

Chapter 4 of this report describes the study assumptions and study methodology of the policy-driven deliverability assessment study analysis performed by the ISO. Using the assumptions and study methodology described therein, a deliverability assessment was performed using the Commercial Interest portfolio. This portfolio has approximately 750 MW of renewable generation modeled in the Kramer zone. As described in chapter 4, the Coolwater-Lugo 230 kV project ensures the deliverability of the 750 MW of renewable generation in the Kramer zone and the 106 MW in the Lucerne zone, in the Commercial Interest portfolio.

In the ISO's assessment, replacing the Coolwater-Lugo project with the AV Clearview Transmission Project alternative caused overloads on the following transmission lines:

- Yeager-Edwards 115 kV;
- Edwards-Holgate 115 kV; and
- Holgate-Kramer 115 kV.

The proposed mitigation for these overloads is to keep the Yeager-Edwards 115 kV line open. With these overloads mitigated by this operating solution, the results of the deliverability study for the AV Clearview Project show the following:

- Baseline Case — approximately 250 MW of additional generation in the Kramer zone can be deliverable above the 750 MW already included in the Commercial Interest Portfolio.
- Expanded Case — approximately 1,250 MW of additional generation in the Kramer and Coolwater areas can be deliverable above the 750 MW already included in the Commercial Interest portfolio.
- The 106 MW in the Lucerne zone are also deliverable. The Jasper substation is assumed to be built to connect this generation to the system, but the cost for Jasper substation is not included in the cost for either project alternative since it is needed to connect renewable generation in the studied portfolios regardless of which alternative is selected.

Depending on the specific location of the additional generation, some level of additional deliverability beyond the amounts identified above may be achievable. As the incremental generation is beyond the amounts identified in the CPUC portfolios used for transmission planning purposes, the ISO has not attempted further refinement to these values.

In the ISO's planning process, the ISO does not assess a financial benefit with accessing additional renewable generation outside of the portfolio development process led by the CPUC. If there is new information that leads the CPUC to identify additional resources that should be considered in subsequent renewable portfolio development cycles, the CPUC would take that into account in its adoption of renewable portfolios.

3.4.5 Production Simulation Study Results

Chapter 5 of this report describes the study assumptions and study methodology of the economically-driven production simulation assessment study analysis performed by the ISO. Using the assumptions and study methodology described therein, the ISO performed a production simulation analysis of the AV Clearview project economic benefits. The addition of the AV Clearview Transmission Project alternative resulted in the following transmission lines being congested in the Commercial Interest portfolio:

- Yeager-Edwards 115 kV;
- Edwards-Holgate 115 kV; and
- Holgate-Kramer 115 kV.

The proposed mitigation for these overloads is to keep the Yeager-Edwards 115 kV line open.

With either the Coolwater-Lugo 230 kV transmission line or the AV Clearview Transmission Project, there was no congestion identified in the study area. Because both proposed network upgrades deliver renewable congestion in the study area, the addition of AV Clearview Transmission Project alternative, in lieu of the Coolwater-Lugo 230 kV line, did not produce any economic benefits that would compensate for the higher costs of the project relative to the Coolwater-Lugo 230 kV project costs.

3.4.6 Access to Windhub Substation

Comments received from stakeholders have provided conflicting opinions on the viability of additional 230 kV interconnections into the Windhub substation. As the ISO focus in the development of this study is in preparation of material intended for the CPUC process, where these issues can be explored, the ISO has not pursued this matter further at this time.

3.4.7 Review of Report provided by Critical Path Transmission

On February 12, 2013, Critical Path Transmission, LLC (Critical Path) submitted a report commissioned by Critical Path comparing the benefits of the AV Clearview project to the South of Kramer (sic) project with preliminary stakeholder comments responding to the draft 2012/2013 transmission plan.

The ISO reviewed the report, and has provided the results of its review with our response to stakeholder comments.

In summary, the ISO concluded that due to assumptions restricting the use of special protections systems in interconnecting renewable generation and other methodology differences, the bulk of the benefits quantified in the report are higher than what the project is likely to produce. As well, a number of transmission capital additions are assumed to be required in the event of the Coolwater-Lugo project, which could be eliminated by the AV Clearview project; the ISO does not agree with the assumptions that those transmission capital additions would in fact be necessary.

Further, the report quantifies benefits post 2020 associated with additional renewable generation the AV Clearview project may make deliverable beyond the CPUC-identified portfolios that the Coolwater-Lugo project can also accommodate. The ISO notes that while some additional renewable capacity benefit is likely for the AV Clearview project, the quantification is higher than ISO projections, and there is a concern of potential double-counting of several of the benefits.

3.4.8 Conclusion

The Coolwater-Lugo 230 kV transmission line was triggered by ISO generation project #125 with an executed LGIA in the serial group as a delivery network upgrade to mitigate the overloads on the Kramer-Lugo #1 & #2 230 kV Lines. SCE's application for the CPCN for the project is anticipated in 2013. The CPUC has indicated that alternatives that support west Mohave renewable generation will need to be considered in the upcoming CPCN proceedings.

Both the Coolwater-Lugo 230 kV Transmission Line and the AV Clearview Transmission Project alternative are effective at delivering the renewable generation in the Kramer zone identified in the table above from the 2012-2013 transmission planning process renewable portfolios.

The cost estimate provided for both AV Clearview alternatives are higher than the estimate provided for the Coolwater-Lugo Project. The AV Clearview project has the potential to allow the deliverability of some level of additional generation beyond the portfolio amounts identified by the CPUC for transmission planning purposes. However, the ISO found that the AV Clearview project did not produce economic transmission benefits that would offset the higher costs of the project relative to the Coolwater-Lugo 230 kV project costs.

The ISO further notes that comments have been received raising concerns with cost and siting issues that the ISO considers are best addressed at the anticipated CPUC proceeding addressing the CPCN for the Coolwater-Lugo project.

In response to the feedback provided by the ISO, Critical Path provided a revised project proposal on February 25, 2013. Having just received this proposal, the ISO did not have adequate time to comprehensively review it prior to finalizing its 2012/2013 Transmission Plan for the March Board meeting. However, we intend to review the latest proposal after the March Board meeting, and will make our conclusions and supporting analysis publicly available for consideration by interested parties.

3.5 Nuclear Generation Backup Plan Studies

3.5.1 Background

As set out in section 4.6 of the Unified Planning Assumptions and Study Plan for the 2012-2013 Transmission Planning Process,[18] the ISO examined the long-term grid reliability impact in the absence of the two nuclear generating stations, Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), which are located in the ISO balancing authority. This section provides the study results that were performed as part of the 2012-2013 transmission planning process.

The studies addressed the recommendations from the CEC, which were made in consultation with the CPUC, in the *2011 Integrated Energy Policy Report* that "to support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and the CEC) should report to the Energy Commission as part of its 2013 IEPR and the CPUC as part of its 2013 Long-Term Procurement Plan on what new generation and/or transmission facilities would be needed to maintain system and/or local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde". The 2011 Integrated Energy Policy Report (IEPR) also recommended that the utilities "should report to the CPUC on the estimated cost of these facilities" (i.e., electrically equivalent replacement generation and/or transmission facilities).

As part of the 2012-2013 transmission planning cycle, two studies related to the nuclear generation backup plan were performed. One addressed the extended outage scenario at DCPP and SONGS for an intermediate time frame (2017-2018). The other considered the reliability concerns and potential mitigation options in the long term (i.e., 2022 time frame). The mid-term study is considered contingency planning for future unplanned long-term outages. The study addressed a request from the CEC 2011 IEPR. The study also incorporates once-through cooling policy implications for generating units that have compliance schedules up to the intermediate 2018 and longer 2022 time frame. The mitigation measures focus on actions that are reasonably implementable by summer 2018. The long-term study (2022) was undertaken by the ISO for information purposes. The study related to DCPP absence focuses on grid reliability implications for northern California and ISO overall. The study related to SONGS absence focuses on grid reliability implications for southern California and ISO overall. The combined DCPP and SONGS absence studies also focused on the grid reliability assessment for the ISO bulk transmission system.

3.5.2 Qualifications for the Grid Assessment Studies

The studies included evaluations for potential transmission reliability concerns and potential mitigation options. These studies are not intended as a basis for a decision to keep or retire the two nuclear generating power plants. Other studies beyond grid reliability assessments would be needed to provide a more complete assessment and would include asset valuations,

[18] 2012/2013 Transmission Planning Process Unified Planning Assumptions and Study Plan (http://www.caiso.com/Documents/2012-2013ISOTransmissionPlanningProcessStudyPlan.pdf)

environmental impacts of green-house gas emissions, compliance with AB 32, impacts on flexible generation requirements, least-cost best-fit replacement options, generation planning reserve margin, market price impacts, customer electricity rate impacts and impacts to natural gas systems for replacement generation. These issues are outside the scope of the ISO's transmission reliability study.

This study focuses on transmission system reliability; it does not address the CEC IEPR report recommendation to consider the loss of the Palo Verde Nuclear Generating Station, because this plant is owned by multiple entities and is located outside the ISO balancing authority. The transmission system impacts of the loss of this generation would need to be considered as part of a coordinated interregional planning process that would include entities, such as Arizona Public Service, Salt River Project, El Paso Electric, PNM Resources, Southern California Public Power Authority[19], and the Los Angeles Department of Water & Power. Loss of the Palo Verde nuclear generation would primarily be considered as a resource issue for the load serving entities in the ISO balancing authority. The ISO, as part of its reliability assessment that is consistent with WECC and NERC reliability standards, has performed studies that include a simultaneous loss of the two Palo Verde generating units as a Category D (extreme event) contingency. The Nuclear Regulatory Commission (NRC) has renewed the operating licenses for Palo Verde's three reactors, thus extending their service life from 40 to 60 years (to 2045 for Unit 1, 2046 for Unit 2, and 2047 for Unit 3).

3.5.3 Relationship with Prior Studies without SONGS

As mentioned above, an intermediate study year for grid reliability assessment (2017/2018) was evaluated for the extended outage scenario. This study was synched with a previously completed study for a 2013 SONGS absence. The completed report, which is an addendum to the 2013 LCR studies for the scenario without SONGS, was posted on the ISO website (link provided here). The 2013 SONGS absence studies included the following recommendations:

- convert Huntington Beach Units 3 and 4 to 2x140 MVAR synchronous condensers;
- install one 79.2 MVAR capacitor bank each at Johanna and Santiago Substations, and two 79.2 MVAR capacitor banks at Viejo Substation; and
- re-configure Barre-Ellis 230kV lines from two to four circuits.

The above mitigation measures were modeled in-service for the 2018 mid-term studies and only the latter two measures were modeled in the 2022 long-term studies. Huntington Beach synchronous condensers were removed from the long-term studies (except in one sensitivity case as noted) because of proposed repowering plan of the Huntington Beach generation by AES Corporation that would require demolition of the existing site for units 3 and 4 to build a second block of combined cycle gas turbine plant.

[19] Not all entities in SCPPA are in ISO BAA.

3.5.4 Key Load Forecast and Resource Assumptions

The following is a summary of key load forecast and resource assumptions used for the studies.

Load Forecast Assumptions

The most recent CEC-adopted 2012-2022 mid-case demand forecast, posted on the agency's website in August 2012, was used for the studies. Consistent with the ISO reliability study methodology, a 1-in-10 year weather-related peak load was utilized for local capacity area reliability assessments. For system wide studies, ISO staff utilized a 1-in-5 year weather-related peak load. Future energy efficiency benefits of 8,000 MW statewide, including continued funding of utility programs, was embedded in the CEC demand forecast. The CEC demand forecast also included the impacts of an additional approximately 800 MW of behind-the-meter distributed generation, for a total of over 3,500 MW. (System-connected distributed generation is discussed in the resource section below.) The following tables provide a summary of the load forecast used in the studies.

Table 3.5-1: Summary of CEC demand forecasts used in the system studies

Area	System Studies (1-in-5 Weather-Related Load + Losses Forecast) (MW)	
	2018	2022
Northern California (NP26)	24,362	25,502
SCE	26,231	27,461
SDG&E	5,528	5,922

Table 3.5-2: Summary of CEC demand forecasts used in the Local Capacity Requirement Studies (LA Basin and San Diego Areas)

Area	Local Capacity Requirement Studies (1-in-10 Weather-Related Load Forecast) (MW)	
	2018	2022
SCE LA Basin Area	21,870	22,917
SDG&E	5,652	6,056

CPUC and CEC Renewable Portfolios

The CPUC's Commercial Interest portfolio was used as the base case for the assessment. The High Distributed Generation (High DG) portfolio was used as sensitivity study case for 2022 assessment to determine how much thermal generation requirements in the LA Basin and San Diego local reliability areas would be lowered if higher penetration of DG could materialize. For more discussions on the renewable portfolios, please refer to section 4.1.

Demand Response

Demand response is considered a supply resource and not a load modifier. This assessment is based on the CEC-adopted mid-case demand forecast with associated committed preferred demand resource programs (such as funded energy efficiency, etc.). Further discussions will take place with the state energy agencies to determine an appropriate level of demand response that could be utilized as mitigations in local reliability areas. Once this is done for specific local reliability areas, further studies can be performed to assess demand response effectiveness in mitigating grid reliability concerns.

3.5.5 Grid Reliability Assessment for the Absence of Diablo Canyon Nuclear Power Plant (DCPP)

A grid reliability assessment was evaluated for the absence of DCPP. This study determined that there was no material mid- or long-term transmission system impacts associated with the absence of Diablo Canyon. However, resource requirements, such as planning reserve criteria and flexible resource needs, would require further study.

The assessment included evaluating the potential transmission reliability concerns and mitigation options. The SONGS was modeled as on line in these studies. This study did not address any issues other than transmission system reliability.

An assessment was performed for the PG&E bulk transmission system with the same methodology that was used for the power flow and stability studies described in section 2.4 (PG&E Bulk Transmission assessment) and for the policy-driven assessment results and mitigations for PG&E area described in section 4.7. 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. The studies also included extreme events such as a Northeast-Southeast separation, outage of all three lines of Path 26 and outages of major substations, such as Los Banos, Tesla and Midway (500 and 230 kV busses).

The base case selected for the studies was the Commercial Interest portfolio from the policy-driven studies. Two timeframes were studied: years 2018 and 2022. For the 2022 scenario, both peak and off-peak conditions were studied while the 2018 scenario only used peak conditions because the off peak case was considered to be less critical. In the base cases with the DCPP off line, generation from the DCPP was replaced by PG&E thermal and peaking generation and hydro generation in the Northwest.

The following table summarizes assumptions about generation and load within the ISO in the case with and without DCPP.

Table 3.5-3: Generation and load assumptions in the Diablo Absence studies

Scenario	Generation		Demand		
	Area	(MW)	Load (MW)	Loss (MW)	Load+Losses (MW)
2018 Summer Peak No DCPP	PG&E	25,779	29,400	1,020	30,420
	SDG&E	3,838	5,351	177	5,528
	SCE	19,082	25,048	540	25,588
	ISO	48,699	59,799	1,737	61,536
2022 Summer Peak with DCPP	PG&E	28,411	30,645	1,093	31,738
	SDG&E	4,138	5,632	196	5,828
	SCE	19,649	25,905	617	26,522
	ISO	52,198	62,182	1,906	64,088
2022 Summer Peak No DCPP	PG&E	27,470	30,645	1,091	31,736
	SDG&E	4,138	5,632	199	5,831
	SCE	19,533	25,905	575	26,480
	ISO	51,141	62,182	1,865	64,047
2022 Summer Off-Peak with DCPP	PG&E	16,274	16,510	723	17,233
	SDG&E	2,230	2,816	65	2,881
	SCE	14,696	12,952	434	13,386
	ISO	33,200	32,278	1,222	33,500
2022 Summer Off-Peak No DCPP	PG&E	15,554	16,510	551	17,061
	SDG&E	2,230	2,816	69	2,885
	SCE	14,021	12,952	422	13,374
	ISO	31,805	32,278	1,042	33,320

Assumptions about the interface flows and Northern California hydro generation dispatch in the cases studied are shown in the table below.

Table 3.5-4: Interface flows in the DCPP Absence Studies

Parameter	2018 Summer Peak No DCPP	2022 Summer Peak with DCPP	2022 Summer Peak No DCPP	2022 Summer Off-Peak with DCPP	2022 Summer Off-Peak No DCPP
California – Oregon Intertie Flow (N-S) (MW)	4,640	4,038	4,662	-2,007	-1,476
Pacific DC Intertie Flow (N-S) (MW)	3,000	3,100	3,100	0	0
Path 15 Flow (S-N) (MW)	495	2,404	358	5,235	2,951
Path 26 Flow (N-S) (MW)	40	753	493	-2,909	-2,918
Northern California Hydro (% Dispatch of Nameplate)	80%	80%	80%	80%	80%

Post transient and transient stability studies were conducted for all the cases. For the post transient (governor power flow) studies, only transmission facilities 115 kV and higher were monitored because as the DCPP is connected on 500 kV, no significant impact of its absence on lower voltage facilities was expected.

The study results are discussed below with only those facilities that are negatively impacted by absence of DCPP.

3.5.5.1 Study Results and Discussion

Thermal Overloads

Round Mountain 500/230 kV transformer

The Round Mountain 500/230 kV transformer was identified as overloaded under off-peak load conditions with an outage of the Olinda 500/230 kV transformer (Category B contingency). This overload was also observed in the policy-driven studies, but in the case with DCPP absent the overload was higher (112 percent versus 107 percent in the Commercial Interest portfolio). The higher Round Mountain transformer loading is explained more by higher generation in this area that replaced DCPP generation than by the absence of the nuclear plant.

The mitigation solution for this overload is to modify the existing Colusa SPS to also monitor transformer outages and Round Mountain transformer overloads. The SPS mitigates the Round Mountain transformer overloads by tripping Colusa generation.

The Round Mountain area and the contingencies that may cause Round Mountain transformer overloads are shown in the following figure.

Figure 3.5-1: Northern California 500/230 kV transformer overloads

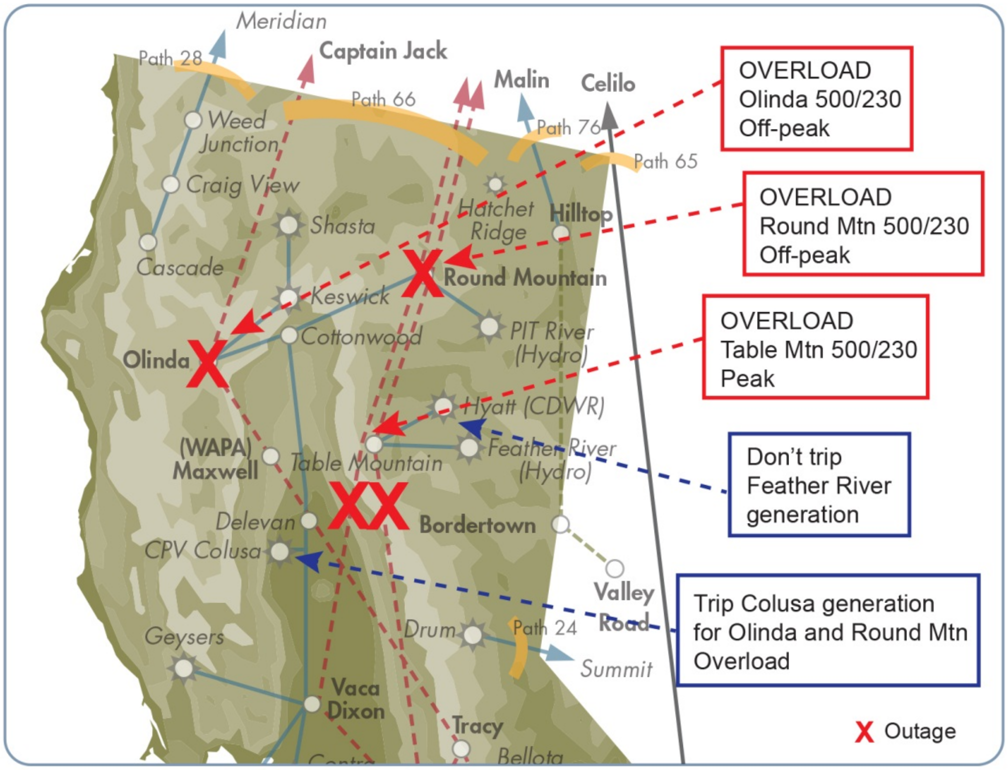


Table Mountain 500/230 kV transformer

The Table Mountain 500/230 kV transformer was identified as loaded up to 99 percent of its normal rating with a 500 kV double outage south of Table Mountain (Table Mountain-Vaca Dixon and Table Mountain – Tesla 500 kV lines) under peak load conditions in 2022. The Table Mountain transformer does not have emergency rating. The reason for the heavy loading was replacing the Diablo generation by Northwest hydro generation and thus higher COI flow. High loading on the Table Mountain 500/230 kV transformer was also identified in the reliability studies (see Chapter 2) with the same contingency and high COI flow.

The mitigation proposed in the reliability studies was to modify the existing RAS for the 500 kV double outage south of Table Mountain so that it would not trip Feather River (Hyatt and Thermalito) generation. This mitigation will also work if the DCPP is out of service.

The Table Mountain area and this contingency are shown in figure 3.5-1.

Olinda 500/230 kV Transformer

The Olinda 500/230 kV transformer was identified as overloaded with a Category B contingency (an outage of the Round Mountain 500/230 kV transformer) under off-peak load conditions. This overload was also identified in the policy-driven studies, but the loading if the DCPP is not generating is higher (112 percent of the transformer emergency rating versus 105 percent in the Commercial Interest portfolio). Higher loading is explained more by higher generation in the area that replaces DCPP generation than by the absence of the nuclear plant.

The mitigation solution to modify the existing Colusa SPS to trip Colusa generation also for transformer outages that is proposed in the policy-driven studies will also mitigate the Olinda 500/230 kV transformer overload in the absence of DCPP.

The Olinda area and the contingency that may cause Olinda transformer overloads are shown in figure 3.5-1.

Delevan-Cortina 230 kV Transmission Line

This transmission line is expected to overload by 1 percent of its emergency rating with an outage of the Olinda-Tracy 500 kV line (Category B) and to overload with several Category C contingencies, with a double outage of both Round Mountain-Table Mountain 500 kV lines being the most critical. The Category B and C overloads are expected under peak load conditions in 2022 and loading up to 100 percent of emergency rating is expected for Category C contingencies under peak load conditions in 2018. Heavy loading of the Delevan-Cortina 230 kV line with Category B and overloads with Category C contingencies were also observed in the policy-driven studies, but with the DCPP not generating, the loading was higher.

A potential mitigation for the overload is installing an SPS to trip generation from the Colusa power plant for Category B contingency and adding Colusa generation to existing SPS for Category C contingencies. Another solution is an upgrade of the Delevan-Cortina 230 kV transmission line. Congestion management that would reduce Colusa generation will also mitigate the overload. These are the same mitigation solutions that were proposed in the policy-driven studies; they will also mitigate the Delevan-Cortina 230 kV line overload if the DCPP is not in service.

The location of the Delevan-Cortina transmission line and the outages that cause its overload are illustrated in the figure below.

Figure 3.5-2: Delevan-Cortina 230 kV line overload

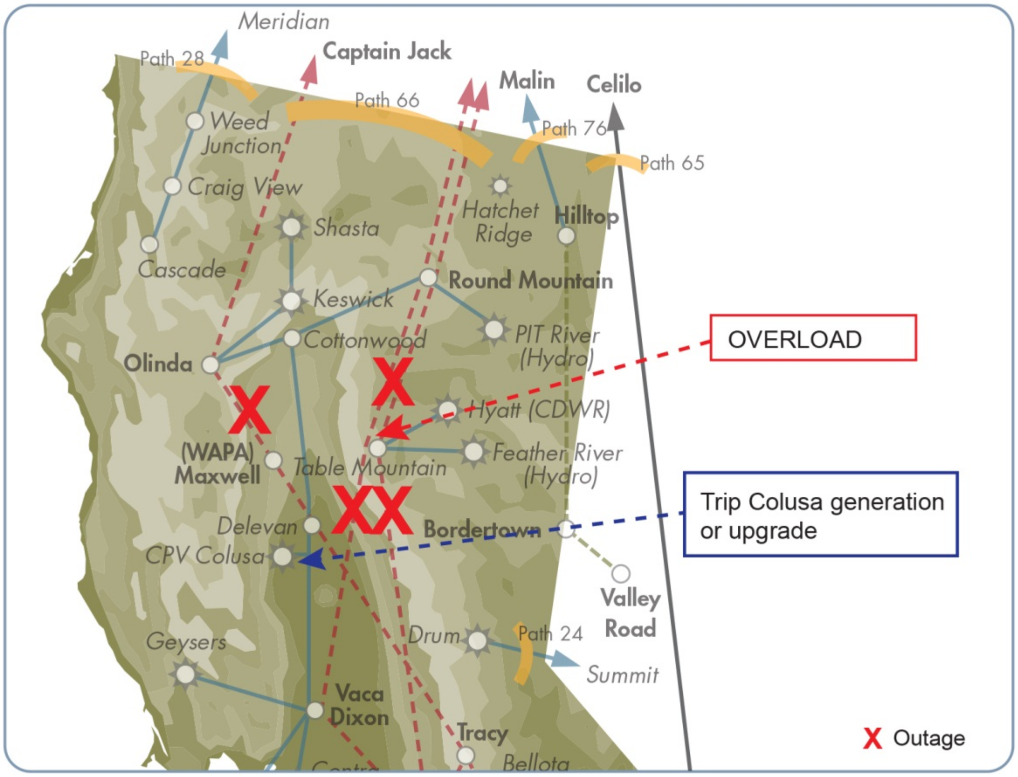


Table 3.5-5 summarizes the overloading concerns in the cases with DCPP and without DCPP in service. Only facilities where absence of DCPP increases overloads or creates new overloads are shown. No overload was identified with the Table Mountain 500/230 kV transformer outage if the existing SPS is applied under off-peak load conditions.

Table 3.5-5: Summary of study results without DCPP

Overloaded Facility	Contingency	Category	Category Description	Loading (%)					
				2018 Summer peak		2022 Summer peak		2022 Summer Off-peak	
				w/out Diablo	with Diablo	w/out Diablo	with Diablo	w/out Diablo	with Diablo
DELEVN - CORTINA 230.0	Olinda-Tracy 500 kV	B	L-1	98.1%		101.0%	99.0%		
	DLO 500 kV Round Mt-Table Mtn #1&2	C	L-2	99.7%		102.8%	103.7%		
	DLO 500 kV south of Table Mtn	C	L-2	99.5%		102.7%	100.7%		
	Table Mtn 500 kV stuck breaker	C	BRK			96.0%	95.6%		
	Tesla 500 kV stuck breaker	C	BRK			95.9%	96.4%		
ROUND MTN 500/230	Olinda 500/230 kV	B	T-1					112.3%	107.4%
OLINDA 500/230 kV	Round Mtn 500/230 kV	B	T-1					112.0%	104.9%
TABLE MTN 500/230	DLO 500 kV south of Table Mtn	C	L-2			98.8%			
RIO OSO - BRIGHTON 230	Table Mtn 500/230 no RAS	B	T-1					105.6%	102.7%
ATLANTC - GOLDHILL 230		B	T-1					100.6%	97.2%

Voltage and Reactive Margin Issues

Voltage and Voltage Deviation Concerns

No voltage or voltage deviation concerns were identified on the PG&E bulk system in the studies without DCPP if all the RAS and SPS are applied. However, with the extreme events (Category D contingencies), such as an outage of the Midway 230 kV substation, tripping of more load may be required if the DCPP is absent, as the absence of the reactive support from DCPP reduces reactive margin in the system.

Although the studies did not show insufficient reactive margin with Category B and C contingencies for the conditions studied, additional studies are required to determine if the system has sufficient reactive margin with higher load.

Transient Stability Concerns

Transient stability studies without DCPP did not identify any additional concerns compared with the policy-driven studies. Compared with the results of the reliability studies described in chapter 2, additional concerns were identified in the policy-driven studies with an outage of the Table Mountain 500/230 kV transformer under off-peak load conditions. They are described in chapter 4. However, the absence of DCPP did not exacerbate these concerns. The same mitigations proposed in the policy-driven studies (modify SPS for the Table Mountain transformer outage and congestion management to limit reverse flow through the Table Mountain transformer) will also mitigate transient frequency concerns if the DCPP is absent. The proposed modified SPS is not expected to cause any overload with the absence of DCPP.

Conclusions for Grid Reliability Assessment of Diablo Canyon Absence Scenarios

The absence of the DCPP appears not to have negative impact on the reliability of the ISO transmission system with the assumption that there is sufficient deliverable generation within the ISO controlled grid.

The absence of DCPP results in avoiding several overloads on the PG&E bulk system during off-peak load conditions (i.e., Westley-Los Banos 230 kV and Gates-Midway 230 kV line overloads).

Category D contingencies will require more load tripping if DCPP is absent because of reduced reactive margin. Additional studies are required to determine if the system has sufficient reactive margin with higher load.

Additional sensitivity studies with lower renewable generation other than CPUC RPS portfolios may be required to confirm these conclusions.

3.5.6 Grid Reliability Assessments for the Absence of San Onofre Nuclear Generating Station (SONGS)

3.5.6.1 2013 SONGS Absence Study

As mentioned previously, the mid-term (2018) and long-term (2022) evaluation included mitigation plans identified and recommended for the short-term (2013) without SONGS scenario. The completed report, which is an addendum to the ISO's 2013 LCR studies for the scenario without SONGS, was posted on the ISO website (link provided here). Transmission reliability study results were included in the "2012-2013 Reliability Assessment: Final Study Results" also posted on the ISO website (link provided here). The 2013 SONGS absence studies included the following recommendations:

- Install one 79.2 MVAR capacitor bank each at Johanna and Santiago Substations, and two 79.2 MVAR capacitor banks at Viejo Substation;
- Re-configure Barre-Ellis 230kV lines from two to four circuits
- Convert Huntington Beach Units 3 and 4 to 2x140 MVAR synchronous condensers;

The capacitor bank projects and the Barre-Ellis re-configurations were approved by the ISO Management for summer 2013 preparedness after a Board of Governors briefing on September 13, 2012 on "2013 Summer Outlook". The capacitor bank projects are expected to be in-service by July 1, 2013. The reconfiguration of the Barre-Ellis lines is expected to be completed by the end of 2013, and be available for the summer of 2014. Authorization to proceed with reliability must run contracts with the Huntington Beach 3 and 4 as synchronous condensers was also approved by the ISO Board of Governors for summer 2013 on September 13, 2012, and the completion of the conversion work on units 3 and 4 prior to summer 2013 is uncertain at this time. Based on this information, the above mitigation measures were modeled in-service for the 2018 mid-term studies. However, for the 2022 long-term studies, only the Barre-Ellis reconfiguration project was modeled and not the Huntington Beach synchronous condensers. Based on AES Corporation's Application for Certification of repowering plan for Huntington Beach power plant, Huntington Beach units 3 and 4 would need to be removed to build a second block of proposed combined cycle gas turbine plant. The exact timing of the start of construction of Block 2 would be dependent on such factors as timing of the CEC decision on the AFC permit, whether the repowering project would have Power Purchase Agreements with Load Serving Entities approved by the CPUC. Therefore to be prudent, the ISO at this time assessed the 2022 long-term grid reliability with the assumptions that these two units (3 and 4) would be removed and unavailable because of the planned construction of the new Block 2 CCGT on the same site.

3.5.6.2 Mid-Term (2018) Reliability Assessment

Local reliability assessments were performed for the LA Basin and its sub-areas (i.e., West LA and Ellis), as well as San Diego-Imperial Valley and San Diego sub-LCR areas. Table 3.5-7 and Table 3.5-8 list the study results for these LCR and sub-LCR areas. Studies were performed initially without the following once-through cooled generating units based on compliance schedule with state OTC policy: El Segundo units 3 and 4, and Encina units 1 - 5. The capacity of these units, as well as SWRCB compliance date and scheduled retirement date, are summarized in the following table.

Table 3.5-6: Capacity of El Segundo and Encina generating units

Generating Plant	**Total Plant Capacity (MW)**	**Individual Unit Capacity (MW)**	**LCR Area**	**SWRCB Compliance Date**	**Scheduled Retirement Date***
El Segundo	670	Unit 3 (335) Unit 4 (335)	LA Basin	12/31/2015 (for both units)	Unit 3 (Q1 2013)**
Encina	946	Unit 1 (106) Unit 2 (103) Unit 3 (109) Unit 4 (299) Unit 5 (329)	San Diego	12/31/2017 (for all of these units)	

Notes:

* Only publicly announced retirement is indicated in the table

**El Segundo Unit 3 is required to shut down to offset air emission credits needed for the El Segundo Energy Center (564 MW) with a target on-line date of June 1, 2013. However, Power Purchase Tolling Agreement (PPTA) with SCE does not start until August 1, 2013.

The following is the summary of these study results:

- For the LA Basin LCR area, the most critical contingency is the overlapping Category C (N-1-1) contingency of Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink (SWPL) 500 kV line. This contingency would cause post-transient voltage instability in the southern region.
- For the Western LA sub-LCR area, the most critical contingency is the Category C contingency of overlapping outage of Serrano – Lewis #1 and Serrano – Villa Park #2 230 kV lines, causing Serrano – Villa Park #1 230 kV line to be overloaded. However, the area has sufficient generation to mitigate this loading concern.
- For the Ellis sub-LCR area, the most critical contingency is the Category C contingency of N-2 of either Barre-Ellis #1 & #2 230 kV lines, or Barre-Ellis #3 & #4 lines, overloading the adjacent Barre-Ellis double circuit tower lines. The area, however, has sufficient generation to mitigate this loading concern.
- For the San Diego sub-LCR area, the following critical reliability concerns were identified:
  - Normal overloads on the Miguel – Bay Blvd. 230kV line, causing a generation deficiency of about 2,132 MW (this overload was also identified in generation interconnection studies and in the policy-driven transmission need assessment);
  - Post transient voltage instability because of overlapping outage of Sunrise Powerlink, followed by SWPL line. With this constraint, this sub-LCR area has a generation deficiency of about 1,835 MW;
  - Thermal overloading concerns for 19 various facilities with voltages from 69 kV to 230 kV. This is due to the absence of SONGS and San Diego northwest generation (for a combined total of 3,211 MW of generation).
- For the San Diego-Imperial Valley LCR area, the most critical contingency is the Category B outage with overlapping G-1 of Otay Mesa and Imperial Valley – North Gila 500 kV line, causing post-transient voltage deviation at SCE-owned Viejo substation. This area, however, has sufficient generation to mitigate the identified reliability concern.

The following are the mid-term mitigation alternatives.

Mitigations (for both Alternative 1 and Alternative 2 below)

Table 3.5-8 lists the transmission facility loading concerns identified in the study with and without various mitigation measures. Two alternative mitigation plans were designed during the course of the study that would mitigate the voltage and facility loading concerns identified. The two alternative mitigation plans were designed with the intent of representing a reasonable range of possible alternatives. Also, during the course of the study the ISO discovered that two particular mitigation measures were highly effective at mitigating a large number of the loading and voltage concerns. It was found that continued reactive support was needed at Huntington Beach in both identified mitigation scenarios. It was also found that over half of the identified loading concerns could be mitigated with a new transmission line connected between the Sycamore and Penasquitos substations. Therefore the following projects listed below are identified as common mitigations to both of the alternative mitigation plans:

- The ISO assumed that the Huntington Beach synchronous condensers will be available for the intermediate (i.e., 2018) time frame and will assume their continued use or equivalent support. This was identified as part of the need for the SONGS absence scenario for summer 2013.
- Installation of 80 MVAR of shunt capacitor each for Johanna and Santiago Substations, and 160 MVAR of shunt caps for Viejo Substation. This was identified as part of the mitigation for the SONGS absence scenario for summer 2013
- Reconfiguration of the Barre – Ellis 230kV lines from two to four circuits. This was also identified in the SONGS absence scenario for summer 2013.
- Constructing an 11-mile 230 kV line from Sycamore to Penasquitos will mitigate over half of the identified thermal loading concerns. This was identified as common mitigation for the Mid-Term alternatives.

Given the long lead time for the Sycamore to Penasquitos line and the need for this line in a reasonable range of possible alternative mitigation plans, next steps for proceeding with the development of this line would need to commence immediately to address the identified mid-term and long-term needs. It is also important to note that, although it was assumed that the Huntington Beach synchronous condensers would be available through 2018, it is still uncertain if this project can be completed. In addition, the ISO has identified that a dynamic reactive support located at SONGS would provide equivalent reactive support. Therefore, in addition to a mid-term and long-term need for dynamic reactive support at SONGS, there is also a potential short-term need as a backup project to the Huntington Beach synchronous condenser project.

Mid-Term Alternative #1

- Add new or replace 820 MW of northwest San Diego generation.
- Add new 300 MW of generation in the southeast San Diego area.
- Install a total of 650 MVAR of dynamic reactive support (i.e., static VAR compensator or synchronous condensers) at SONGS (or its proximity) and San Luis Rey[20] Substations.
- Common mitigations (Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line)

Mid-Term Alternative #2

- Add new or replace 965 MW of northwest generation in San Diego.
- Install a total of 1,460 MVAR of SVC or SC for dynamic reactive support at SONGS, Talega, Penasquitos, San Luis Rey and Mission Substations.
- Common mitigations (Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line)

The figure below provides an illustration of the above mitigation alternatives.

[20] San Luis Rey is the first preferred location; if this is not feasible, second preferred location is Talega Substation. SDG&E submitted the proposed Talega synchronous condensers into the ISO Request Window.

Figure 3.5-3: Mid-term mitigation alternatives for loss of SONGS

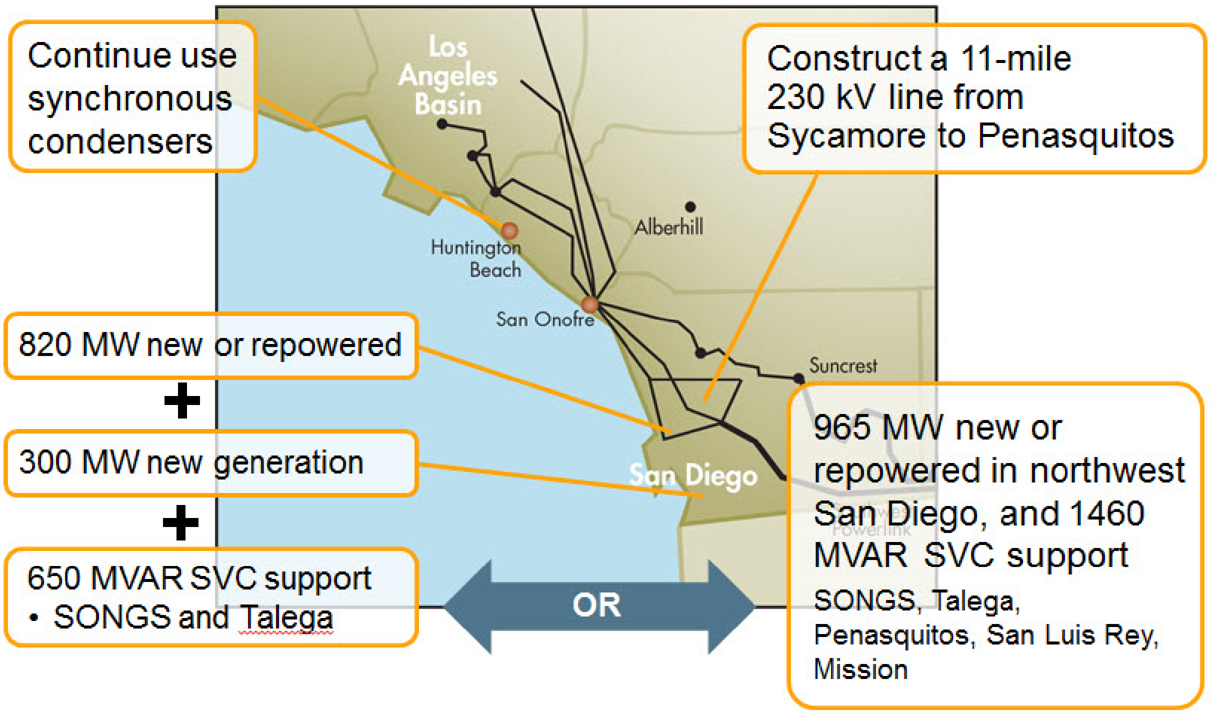


Table 3.5-7: 2018 Local reliability assessment of LA Basin and San Diego areas

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Total Generation (MW)	10,918	6,540		2,135	4,361
Category A	N/A	N/A	N/A	Normal conditions	N/A None other than the ones identified in the San Diego sub-area
Identified Reliability Concerns				Normal overloads on Miguel - Bay Blvd. 230kV line (20%)	
Required Generation (MW)				4,267	
Deficiency (MW)				(2,132)	
Category B	N/A Category C contingency is the overriding contingency for LCR need for this area	N/A Category C contingency is the overriding contingency for LCR need for this sub-area	N/A	G-1/N-1: Palomar CCGT/Miguel-Mission 230kV #1 line	G-1/N-1: Otay Mesa/IV-N.Gila 500kV
Identified Reliability Concerns	Category C reliability concerns established LCR needs	Category C reliability concerns established LCR needs	Category C reliability concerns established LCR needs	Emergency overloads on Miguel - Bay Blvd. 230kV line (10%)	Post-transient voltage deviation beyond 7% at SCE's Viejo 230kV
Required Generation	See notes above	See notes above	See notes above	3,382	4,191
Category C	N-1-1: Sunrise, system adj., followed by SWPL	N-1-1: Serrano-Lewis #1, followed by Serrano-Villa Park #2 230kV	N-2: Barre-Ellis #1&2 or Barre-Ellis #3&4 230kV lines	N-1-1: Sunrise, system adj., followed by SWPL	Category B contingency is the overriding contingency for LCR need for this area
Identified Reliability Concerns	Post-transient voltage instability	Overloading concern on the Serrano-Villa Park #1 230kV line	Overloading of the remaining DCTL Barre-Ellis 230kV lines	Post-transient voltage instability	See notes above

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Description of Mitigations	(1) Continue using HB synchronous condensers AND replace or add new generation in San Diego (820 MW in the northwest and 300 MW in the southeast) AND install 650 MVAR of SVC/SC support at SONGS and Talega; (2) Continue using HB synchronous condensers AND replace or add new 965 MW generation in the northwest San Diego AND install total of 1460 MVAR of SVC/SC support at SONGS, Talega, Penasquitos, San Luis Rey and Mission	Existing generation is adequate to mitigate identified reliability concerns		(1) Replace or add new generation in San Diego (820 MW in the northwest and 300 MW in the southeast) AND install 650 MVAR of SVC/SC support at SONGS and Talega; (2) Replace or add new 965 MW generation in the northwest San Diego AND install total of 1460 MVAR of SVC/SC support at SONGS, Talega, Penasquitos, San Luis Rey and Mission	
LCR Area's Total Required Generation	(1) Total 10,846 MW (included 251 MW DG) - Option 1 (2) Total 10,846 MW - Option 2	Total 4,931 MW (included 251 MW D.G.)	48 MW	(1) 3,255 MW (=2,135 + 820 + 300) (2) 3,100 MW (=2,135 + 965)	See notes above
Deficiency (MW)	(1) None - Option 1 (2) None - Option 2	None	None	If there is no mitigation measure, the local area would be subject to a deficiency of (1,835) MW (1) None if mitigating 1,120 MW generation deficiency (820 MW northwest and 300 MW southeast)	See notes above

	LA Basin	W. LA	Ellis	San Diego	SD/IV
				(2) None if mitigating 965 MW generation deficiency (northwest S/D generation)	

Table 3.5-8: Identified thermal loading concerns for 2018 base case study and evaluation of mitigation measures

	From	kV	To	kV	ck	2018 Loading Concerns (absence of S/D northwest generation and SONGS)	2018 with San Diego northwest generation on-line	2018 with San Diego northwest generation and SONGS generation on-line	2018 with absence of S/D northwest generation and SONGS - Construct Sycamore-Penasquitos 230kV line	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 520 MW S/D northwest generation	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 820 MW S/D northwest generation	Column at immediate left with IID renewable related upgrades	Outage description
1	B	69	SILVERGT	69	2	1.010	0.973	0.935	0.954				Line B 69.0 to SILVERGT _Line SILVERGT 69.0 to URBAN
2	BAY BLVD	230	MIGUEL	230	1	1.198	1.089	0.945	0.994	0.947			Base system (n-0)
3	BAY BLVD	230	MIGUEL	230	1	1.003	0.907	0.774	0.783				Line PEN 230.0 to SYCAMORE 230.0 Circuit 1
4	CHCARITA	138	SHADOWR	138	1	1.167	0.690	0.774	1.077	0.398			Line BATIQTP 138.0 to PENSQTOS _Tran ENCINA 230.00 to ENCINA
5	ESCNDIDO	69	SANMRCOS	69	1	1.166	1.057	0.918	0.896				Line BERNDOTP 69.0 to R.SNTAFE _Line PEN 230.0 to ENCINATP
6	IMPRLVLY	230	ELCENTRO	230	1	1.295	1.052	0.727	1.311	1.176	1.101	0.556	Line LRP-U1-A 230.0 to INTB _Line N.GILA 500.0 to IMPRLVLY

	From	kV	To	kV	ck	2018 Loading Concerns (absence of S/D northwest generation and SONGS)	2018 with San Diego northwest generation on-line	2018 with San Diego northwest generation and SONGS generation on-line	2018 with absence of S/D northwest generation and SONGS - Construct Sycamore-Penasquitos 230kV line	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 520 MW S/D northwest generation	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 820 MW S/D northwest generation	Column at immediate left with IID renewable related upgrades	Outage description
7	MIGUEL	230	MIGUEL	500	2	1.067	0.957	0.797	1.042	0.965			Line BORDER 69.0 to LRKSP_BD _Tran MIGUEL 230.00 to MIGUELMP
8	MIGUEL	230	MIGUEL60	138	1	1.060	0.989	0.927	1.009	0.976			Line BERNDOTP 69.0 to R.SNTAFE _Line PRCTRVLY 138.0 to MIGUEL
9	MIGUEL	500	MIGUELMP	500	1	1.078	0.964	0.800	1.053	0.974			Tran MIGUEL 230.00 to MIGUEL 500.00 Circuit 2
10	MIGUEL	230	MISSION	230	1	1.030	0.928	0.790	0.805				Line BORDER 69.0 to BORDERTP _Line BAY BLVD 230.0 to MIGUEL
11	MIGUEL	230	MISSION	230	2	1.024	0.922	0.786	0.800				Line BORDER 69.0 to BORDERTP _Line BAY BLVD 230.0 to MIGUEL
12	OLD TOWN	230	MISSION	230	1	1.086	0.948	0.844	0.608				Line BORDER 69.0 to BORDERTP _Line BAY BLVD 230.0 to MIGUEL

	From	kV	To	kV	ck	2018 Loading Concerns (absence of S/D northwest generation and SONGS)	2018 with San Diego northwest generation on-line	2018 with San Diego northwest generation and SONGS generation on-line	2018 with absence of S/D northwest generation and SONGS - Construct Sycamore-Penasquitos 230kV line	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 520 MW S/D northwest generation	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 820 MW S/D northwest generation	Column at immediate left with IID renewable related upgrades	Outage description
13	PENSQTOS	230	OLD TOWN	230	1	1.021	0.757	0.501	0.260				Base system (n-0)
14	POWAY	69	POMERADO	69	1	1.114	1.086	0.998	0.996	0.985			Line ARTESN 69.0 to SYCAMORE _Line SYCAMORE 69.0 to BERNARDO
15	POWAY	69	R. CARMEL	69	1	1.291	1.262	1.181	1.194	1.179			Line ARTESN 69.0 to SYCAMORE _Line SYCAMORE 69.0 to BERNARDO
16	SWEETWTR	69	MONTGYTP	69	1	1.024	0.950	0.865	0.893				Line BORDER 69.0 to SALT CREEK _Line SILVERGT 230.0 to BAY BLVD
17	SWEETWTR	69	SWTWTRTP	69	1	1.241	1.125	0.977	1.031	0.935			Line SILVERGT 230.0 to BAY BLVD 230.0 Circuit 1
18	SYCAMORE	230	PENASQUITOS	230	1	N/A	N/A	N/A	0.967				Base system (n-0)
19	SYCAMORE	69	BERNARDO	69	1	1.045	1.021	0.944	0.941				Line ARTESN 69.0 to SYCAMORE _Line POWAY 69.0 to

	From	kV	To	kV	ck	2018 Loading Concerns (absence of S/D northwest generation and SONGS)	2018 with San Diego northwest generation on-line	2018 with San Diego northwest generation and SONGS generation on-line	2018 with absence of S/D northwest generation and SONGS - Construct Sycamore-Penasquitos 230kV line	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 520 MW S/D northwest generation	2018 with absence of SONGS - Construct new Syc.-Penasq. 230kV line, Replaced or New 820 MW S/D northwest generation	Column at immediate left with IID renewable related upgrades	Outage description
													POMERADO
20	SYCAMORE	138	CHCARITA	138	1	1.536	0.324	0.418	1.440	0.683			Line BATIQTP 138.0 to PENSQTOS _Tran ENCINA 230.00 to ENCINA
21	SYCAMORE	69	SCRIPPS	69	1	1.195	1.067	0.965	0.739				Line BERNDOTP 69.0 to R.SNTAFE _Line BAY BLVD 230.0 to MIGUEL
22	SYCAMORE	230	SYCAMORE	69	3	1.002	0.970	0.932	0.800				Line BERNARDO 69.0 to FELCTATP _Tran SYCAMORE 230.00 to SYCAMORE

Long-Term (2022) Reliability Assessment

For the long-term reliability assessment of the LA Basin, San Diego/Imperial Valley and their LCR sub-areas, the mid-term (2018) mitigation plans were included in the long-term (2022) study cases prior to performing contingency studies. The following OTC plants in the LA Basin, in addition to the list in the mid-term assessment, were assumed to be off line in the starting 2022 study cases because of the compliance schedule as reflected in the state's OTC policy (the need for these plants would be characterized in the mitigation plans as the need for replacement generation without reference to specific names of the generating units):

Table 3.5-9: Capacity of OTC generating units in the LA Basin

Generating Plant	Total Plant Capacity (MW)	Individual Unit Capacity (MW)	LCR Area	SWRCB Compliance Date	Scheduled Retirement Date*
Alamitos	2011	Unit 1 (175) Unit 2 (175) Unit 3 (332) Unit 4 (336) Unit 5 (498) Unit 6 (495)	LA Basin	12/31/2020	
Huntington Beach	904	Unit 1 (226) Unit 2 (226) Unit 3 (225) Unit 4 (227)	LA Basin	12/31/2020	Unit 3 (11/2012)** Unit 4 (11/2012)**
Redondo Beach	1343	Unit 5 (179) Unit 6 (175) Unit 7 (493) Unit 8 (496)	LA Basin	12/31/2020	

Notes:

* Only publicly announced retirement is indicated in the table

**Huntington Beach Units 3 and 4 were retired in January 2012 to provide offsets for emission credits required by the new Walnut Creek Energy Center (500 MW), scheduled to be on-line in June 2013. However, these two units were brought back to service for the summer 2012 due to extended outage of SONGS.

Table 3.5-12 provides the results of the local reliability assessments. In summary, the following are identified reliability concerns:

- For the LA Basin LCR area, the most critical contingency is the same as in 2018 studies (i.e., Category C of overlapping outage of the Sunrise Powerlink, system readjusted, followed by the outage of the SWPL line). The constraint is post-transient voltage instability.
- For the Western LA sub-area, the most critical contingency continues to be Category C of overlapping outage of the Serrano-Lewis #1, followed by the Serrano-Villa Park #2 230 kV line. The constraint is thermal overloads on the Serrano-Villa Park #1 230 kV line.
- For the Ellis sub-area, the constraint is due to normal overloads on the Barre-Lewis 230 kV line (7 percent).
- For the San Diego sub-area, the most critical contingency is the same as of the LA Basin (i.e., N-1-1 of Sunrise, followed by SWPL line). The constraint is post-transient voltage instability.
- For the San Diego/Imperial Valley LCR area, the most critical contingency is the Category B outage of the overlapping G-1 of Otay Mesa, followed by an outage of the Imperial Valley-N.Gila 500kV line. The constraint is post-transient voltage deviation at various transmission buses in SCE area.

There are two major mitigation plans evaluated for the long-term, which include two generation alternatives and a combination of transmission and generation alternative. They are described in the following.

Generation Alternatives

Two generation mitigation strategies were explored, as set out below.

<u>Generation Alternative No. 1: Minimizing Generation in San Diego</u>

This mitigation strategy explored minimizing generation in the San Diego area, and then determining generation requirements in the LA Basin.

For this option, Huntington Beach synchronous condensers are assumed not available because of AES Corp. repowering plan.

- Replace existing and add new generation, totaling 4,300 MW – 4,600 MW in the LA Basin to mitigate post-transient voltage instability following the Category C contingency in San Diego.
- To simultaneously mitigate thermal loading concerns in the Western LA sub-area, approximately 2,460 MW of the replaced and/or new generation would need to be sited in the southwestern part of the LA Basin to be most effective. It can be seen in Table 3.5-10 that this condition would be satisfied from this action.
- The maximum amount of generation requirements above can be reduced by about 300 MW if installing an additional 550 MVAR of SVC is feasible at the San Onofre 230 kV switchyard (or in an electrically equivalent location).

Generation Alternative No. 2: Minimizing Total Generation in LA Basin and San Diego

This mitigation strategy explored minimizing total generation requirements in the LA Basin due to potential air emission credit constraints.

For this option, Huntington Beach synchronous condensers are assumed to be available.

- Replace existing and add new generation with about 1,360 MW in the northwestern LA Basin and 2,460 MW in the southwestern LA Basin area. As in the above, to simultaneously mitigate thermal overloading concerns in the Western LA Basin sub-area, about 2,460 MW of this generation would need to be sited in the southwestern part of the LA Basin to be most effective, which appears to be satisfied based on the amount of generation need for the area.
- Continue to rely on the Huntington Beach synchronous condensers, which would reduce the total amount of generation repowering planned for Huntington Beach plant by half.
- Add about 920 MW of new or replaced generation in the San Diego area. The locations for these generation additions are indicated in table 3.5-8.

A summary table (Table 3.5-10) is provided below to show the generation need, as well as dynamic reactive support need by the sub-areas in LA Basin and San Diego LCR areas. This table provides a summary of generation and dynamic reactive support need for the Mid-Term (2018) and the incremental need for the Long-Term (2022) Generation alternatives. The left half of the table lists the amount of OTC generation replacement and new generation assumptions as well as dynamic reactive support need identified for the Mid-Term (2018) mitigation. The middle section of the table lists incremental generation need, as well as incremental dynamic support need, for the Long-Term (2022) mitigation. The total generation and dynamic reactive support need by 2022 is summarized in the far right of the table. The critical contingency that requires these mitigations is the Category C contingency (i.e., N-1-1 of Sunrise, followed by SWPL line out[21]), which causes post-transient voltage instability. The mitigations were tested by applying the mandated WECC post-transient study methodology, in which a positive margin must be obtained successfully for the system modeled with 2.5 percent more loads under a Category C contingency.

It is noted that the new Sycamore – Penasquitos 230kV line is mitigation common to the Mid-Term and Long-Term mitigation identified in the following table.

[21] Cross-tripping of the Otay Mesa – Tijuana 230kV line was also simulated as part of the existing SPS in response to the N-1-1 contingency to avoid overloading the CFE transmission system.

Table 3.5-10– Summary of Mid-Term and Long-Term (generation) options

Summary of Generation & Dynamic Reactive Support Need (No SONGS Analyses) - Mid-Term and Long-Term (Generation) Options

	2018 (Mid-Term)^			2022 (Long-Term) - Generation Options (Incremental Need)			Total Generation & Dynamic Support Need By 2022	
Area	OTC Replacement Assumptions (MW)	New Generation* (MW)	Dynamic Reactive Support Need (MVAR)	OTC Replacement Assumptions (MW)	New Generation* (MW)	Dynamic Reactive Support Need (MVAR)	Total Dynamic Support Need (MVAR)	Total Generation Need (MW)
Alternative #1								
Southwestern LA Basin	0	0	280 (HB)! + 400/500**	2900	1000 - 1200	550 #	500 - 1050 #	3915 - 4115
Northwestern LA Basin	0	0	0	0	300	0	0	300
Eastern LA Basin	0	0	0	0	100 - 200	0	0	100 - 200
Subtotal LA Basin			*280 (HB)! + 400/500 ***	*4315 - 4615 ◊ #*		*550 #*	*500 - 1050*	*4315 - 4615 #*
Northwest San Diego	620/820 +	0	240 !!	++ ◊	0	240 !!	480	620/820 ++ ◊
Southwest San Diego	0	0	!!	0	0	2x240 !!	480	0
Southeast San Diego	0	300	0	0	0	0		300
Subtotal San Diego	*920/1120*		*240 !!*	*(Minimum 920 carried from 2018)*		*720 !!*	*960*	*920/1120 ◊*
Alternative #2								
Southwestern LA Basin	0	0	280 (HB)! + 500	2460	0	0	280 (HB)! + 500	2460
Northwestern LA Basin	0	0	0	1360	0	0	0	1360
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin	*0*		*280 (HB)! + 500*	*3820*			*280 (HB)! + 500*	*3820*
Northwest San Diego	965 $	0	2x240 (new)	520 $	0	0	480	1485
Southwest San Diego	0	0	2x240 (new)	0	0	0	480	0
Southeast San Diego	0	0	0	400 $	0	0	0	400
Subtotal San Diego	*965*		*960*	*920*			*960*	*1885*

Notes: ^ Common transmission line need: Sycamore-Penasquitos 230kV line

* New generation can replace OTC generation if in the same vicinity area
** Need: 400 MVAR with design provision for future expansion for additional 100 MVAR (may need to be upgraded to 500 MVAR between 2018 - 2022 time frame)
# Generation need may be reduced by 300 MW by adding an additional 550 MVAR SVC at San Onofre switchyard
+ This can be accomplished by combining a minimum of 620 MW generation replacement/repowering; the remaining (200 MW) generation need is OTC-extended until further development in the long term
++ Need a minimum of 620 MW OTC permanent replacement or new geneneration in the N/W S/D vicinity area (this part is carried over from the larger 2018 mitigation)
! ISO assumes HB synchronous condensers to be available for 2018 (for 2022 if HB repowering occurs for one CCGT block only)
!! Reactive support need to be expanded with additional 720 MVAR in San Diego between 2018 - 2022 time frame for a total of 960 MVAR in San Diego in 2022
$ If total San Diego generation replacement and new generation is 1120 MW for mid-term (2018), then the additional need is 765 MW for 2022
◊ Approximately 200 MW of generation in the West LA Basin can be lowered if 200 MW if generation is developed in San Diego

Combined Transmission and Generation Alternative

This mitigation strategy tested the effectiveness of adding a major 500 kV reinforcement in the area, and minimizing overall generation requirements.

Table 3.5-11 below provides a summary of generation and dynamic reactive support need for the Mid-Term (2018) and the incremental need for the Long-Term (2022) Combined Transmission and Generation alternatives. The left half of the table lists the amount of OTC generation replacement and new generation assumptions as well as dynamic reactive support need identified for the Mid-Term (2018) mitigation. The middle section of the table lists incremental generation need, as well as incremental dynamic support need, for the Long-Term (2022) mitigation. The total generation and dynamic reactive support need by 2022 is summarized in the far right of the table. The critical contingency that requires these mitigations is the Category C contingency (i.e., N-1-1 of Sunrise, followed by SWPL line out[22]), which causes post-transient voltage instability. The mitigations were tested by applying the WECC post-transient study methodology, in which a positive margin must be obtained for the system with 2.5 percent more loads under a Category C contingency.

The following transmission line was modeled as common mitigation for the combined transmission & generation alternatives:

- Construct a new 65-mile 500kV line between Alberhill and Suncrest Substation with 70 percent compensation to reduce reactive power losses contributing to voltage stability concerns during contingencies because of high flows from the SCE to the SDG&E electric system.

[22] Cross-tripping of the Otay Mesa – Tijuana 230kV line was also simulated as part of the SPS in response to the N-1-1 contingency to avoid overloading the CFE transmission system.

Table 3.5-11– Summary of Mid-Term and Long-Term (combined transmission & generation) alternatives

Summary of Generation & Dynamic Reactive Support Need (No SONGS Analyses) - Combined Transmission & Generation Alternatives

	2018 (Mid-Term)^			2022 (Long-Term) - Combined Transmission Line and Generation Option (Incremental Need)			Total Generation & Dynamic Reactive Support Need by 2022	
Area	**OTC Replacement Assumptions (MW)**	**New Generation* (MW)**	**Dynamic Reactive Support Need (MVAR)**	**OTC Replacement Assumptions (MW)**	**New Generation* (MW)**	**Dynamic Reactive Support Need (MVAR)**	**Total Dynamic Support Need (MVAR)**	**Total Generation Need (MW)**
Alternative #1								
Southwestern LA Basin	0	0	280 (HB)! + 400/500 **	2915	0	0	500	2915
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin	*0*		*280 (HB)! + 400/500 *****	*2915*			*500*	*2915*
Northwest San Diego	820	0	240 !!	360	0	240 !!	480	1180
Southwest San Diego	0	0	!!	0	0	2x240 !!	480	0
Southeast San Diego	0	300	0	0	100	0	0	400
Subtotal San Diego	*1120*		*!!*	*460*		*720 !!*	*960*	*1580*
Alternative #2								
Southwestern LA Basin	0	0	280 (HB)! + 500 (new)	2915	0	0	500	2915
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin			*280 (HB)! + 500 (new)*	*2915*			*500*	*2915*
Northwest San Diego	965	0	2x240	215	0	0	480	1180
Southwest San Diego	0	0	2x240	0	0	0	480	0
Southeast San Diego	0	0	0	0	400	0	0	400
Subtotal San Diego	*965*		*960*	*615*			*960*	*1580*

Notes: ^ Common transmission line need: Sycamore-Penasquitos 230kV line

* New generation can replace OTC generation if in the same vicinity area

** Need: 400 MVAR with design provision for future expansion for additional 100 MVAR (may need to be upgraded to 500 MVAR between 2018 - 2022 time frame)

\+ Can be accomplished by combining a minimum of 620 MW replacement/repowering and the remaining generation need is OTC-extended until further generation development in the long term (2022)

++ Need a minimum of 620 MW OTC replacement or new geneneration in the N/W S/D vicinity area (this part is carried over from the larger 2018 mitigation),(see notes + above for residual need in 2018)

! ISO assumes HB synchronous condensers to be available for 2018 (for 2022, assumes that all HB units would be repowered)

!! Reactive support need to be expanded with additional 720 MVAR in San Diego between 2018 - 2022 time frame for a total of 960 MVAR in San Diego in 2022

◊ Approximately 100 MW of generation in the West LA Basin can be lowered if 100 MW if generation is developed in San Diego

The following two figures illustrate the generation and combined transmission and generation alternatives. Note that both assume the mid-term mitigations were put in place and remain in place.

Figure 3.5-4: Long-term generation alternatives

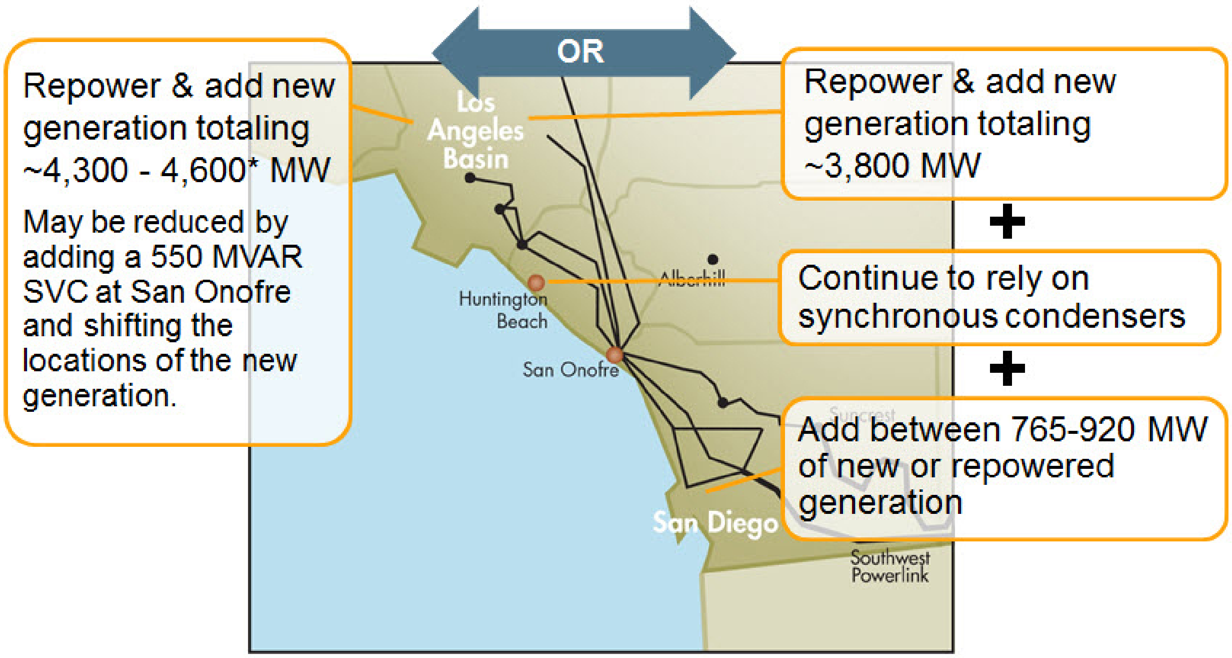
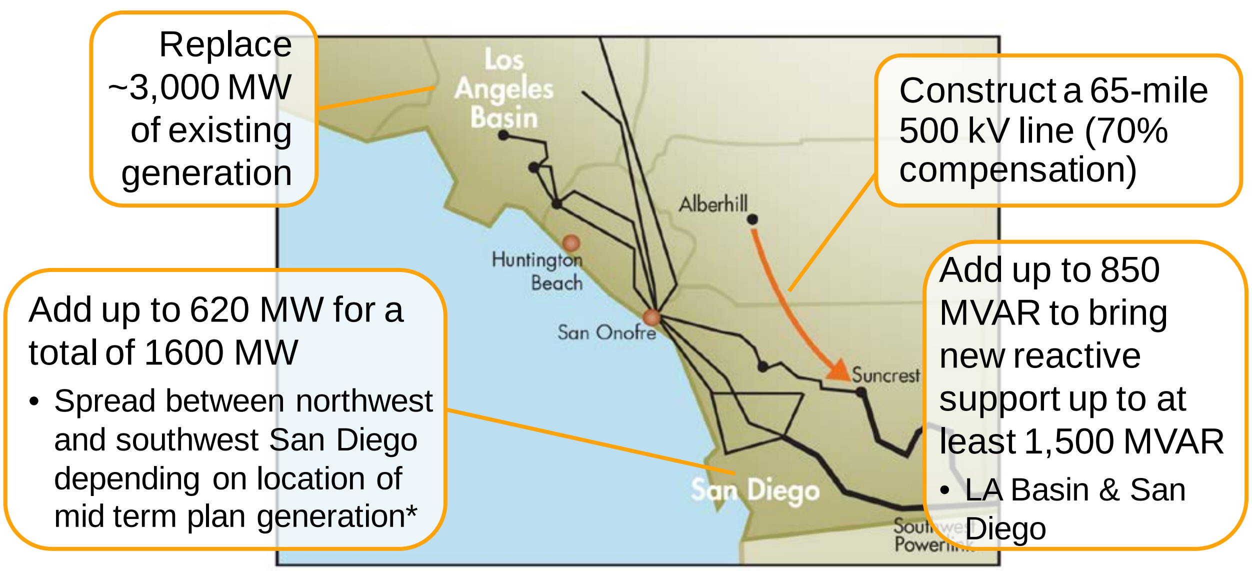


Figure 3.5-5: Long-term combined transmission and generation alternative



***Approximately 700 MW of generation in San Diego can be displaced by additional reactive support, transformer upgrades and 66 kV transmission upgrades in the LA Basin and upgrading line series capacitors and additional transformer upgrades.**

Table 3.5-12: 2022 Local reliability assessment of LA Basin and San Diego areas

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Total Generation (MW)	7,112	2,734		3,100	4,361
Category A	N/A	N/A	One Category A – normal overloads	N/A Category C contingency is the overriding contingency for LCR need for this sub-area	N/A None other than the ones identified in the San Diego sub-area
Identified Reliability Concerns			Barre-Lewis 230kV line (7% overloads)		
Required Generation (MW)			543 MW (386 MW thermal/157 MW DG)		
Deficiency (MW)			(386)* *This is mitigated by any of the mitigation plans for Category C (N-1-1) for LA Basin and San Diego areas if this portion of generation addition is in the southwest area of LA Basin		
Category B	N/A Category C contingency is the overriding contingency for LCR need for this area	N/A Category C contingency is the overriding contingency for LCR need for this sub-area	N/A	Same notes as above	G-1/N-1: Otay Mesa/IV-N.Gila 500kV
Identified Reliability Concerns	Category C reliability concerns established LCR needs	Category C reliability concerns established LCR needs	Category A reliability concerns establish LCR needs	Same notes as above	Post-transient voltage deviation beyond 7% at SCE's Viejo 230kV

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Required Generation	See notes above	See notes above	See notes above	N/A	5,304* *The deficiency of 943 MW (=4361-5304) would be mitigated by any of the mitigation plans for Category C (N-1-1) for LA Basin and San Diego areas
Category C	N-1-1: Sunrise, system adj., followed by SWPL	N-1-1: Serrano-Lewis #1, followed by Serrano-Villa Park #2 230kV	See notes above	N-1-1: Sunrise, system adj., followed by SWPL	Category B contingency is the overriding contingency for LCR need for this area
Identified Reliability Concerns	Post-transient voltage instability	Overloading concern on the Serrano-Villa Park #1 230kV line (36% overloads)	See notes above	Post-transient voltage instability	See notes above
Description of Mitigations – **Generation Options**	(1) Replace and add new generation totaling 4,300 – 4,600 MW* Notes: * the maximum generation level may be reduced by adding another 550 MVAR SVC at San Onofre 230kV bus (or in new substation in proximity of the existing switchyard) (2) Replace and add new generation totaling 3,800	In association with LA Basin mitigation, if 2,460 MW of OTC generation is replaced or new generation is added in the southwestern part of the LA Basin, the thermal loading concern for Western LA sub-area would be mitigated.		Generation Options (see LA Basin for coordinated plan) (1) No new additional generation in San Diego area (2) Add between 765 – 920 MW of new or replaced generation	

	LA Basin	W. LA	Ellis	San Diego	SD/IV
	MW, AND Continue to rely on HB synchronous condensers, AND Add between 765 – 920** MW of new or replaced generation in San Diego (**lower number corresponds to higher generation addition/replacement in 2018 in San Diego area and vice versa), AND Add 820 MVAR of additional dynamic reactive support in LA Basin and San Diego areas if 2018 plan has minimum amount of voltage support				
LCR Area's Total Required Generation – for Generation Options	(1) Total 11,412 – 11,712 MW (included 251 MW DG) – lower number corresponds to scenario if additional 550 MVAR SVC can be installed at San Onofre 230kV bus (2) Total 10,912 MW in LA Basin	Total 5,099MW		(1) Total 3,100 MW (2) Total 3,865 – 4,020 MW (=3,100+765 or +920)	See notes above

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Deficiency (MW)	Without additional new or replaced generation, the area would be subject to 3,800 – 4,600 MW of resource deficiency (1) With Gen. Option 1 - none (2) With Gen. Option 2 - none	(2,460)* *This deficiency is mitigated by new or replaced generation in the LA Basin, if 2,460 MW of new or replaced generation is sited in Southwestern LA area	None		See notes above
Description of Mitigations – Combined Transmission & Generation Option	3.2.1 Replace 3,000 MW of existing generation in the southwestern LA Basin, AND 3.2.2 Construct a 65-mile 500kV line (70% compensation) from Alberhill to Suncrest substations, AND 3.2.3 Add up to about 660 MW for a total of 1600 – 1700 MW of new or replaced generation in San Diego area, AND Add up to 850 MVAR to bring new reactive support up to at least 1,500 MVAR in LA Basin and San Diego areas			Please see mitigation plan under LA Basin area for common plan between LA Basin and San Diego LCR areas	

3.5.6.3 Grid Reliability Assessment of the Absence of SONGS Scenarios Conclusions

Uncertainty in the Studies

In performing the reliability assessment without SONGS for the mid-term and long-term mitigation considerations, there is significant uncertainty inherent in the studies and conclusions as follows:

- future status of SONGS;
- status of pending and future SDG&E generation procurement;
- status of converting Huntington Beach 3 and 4 to synchronous condensers;
- status of meeting flexible generation requirements;
- increasing levels of energy efficiency on top of funded programs in the CEC-adopted demand forecast; and
- potential successful deployment of improved demand response programs.

Least-Regret Considerations for the Mid-Term Needs

Because of the uncertainty factors listed above, ISO management's conclusions reflect the following least-regret considerations:

- The Sycamore – Penasquitos 230kV line provides mitigation for the absence of SONGS, as well as mitigation of policy-driven needs as set out in chapter 4; and
- A total of approximately 700 MVAR of dynamic reactive support in both LA Basin and San Diego areas provides mitigation for the absence of SONGS in a wide range of conditions, and an SVC at SONGS in particular can also provide a backup in the near term if the Huntington Beach synchronous condensers do not materialize.

Given the long lead time for the Sycamore to Penasquitos line and the need for this line in a reasonable range of possible alternative mitigation plans, the ISO is recommending proceeding with the development of this line. Given the uncertainty regarding the Huntington Beach synchronous condensers, the ISO has identified that dynamic reactive support located in the vicinity of SONGS would provide equivalent reactive support, and is also recommending this upgrade as a backup project to the Huntington Beach synchronous condenser project. Additional dynamic reactive support in the San Diego area could also provide immediate reliability benefits, so the ISO is recommending moving forward with these projects as well.

Further Study Works in the ISO 2013/2014 Transmission Planning Cycle for refinement of the Long-Term Needs

The following are ISO's preliminary considerations for additional studies in the upcoming transmission planning cycle:

- work with the CEC to develop refined energy efficiency assumptions;
- work to advance demand response programs that are suited for transmission mitigations;
- consider the need for additional mitigation; and
- consider further studies to evaluate resource requirements, such as planning reserve criteria and flexible resource needs.

3.5.7 Combined Diablo Canyon and SONGS Absence Grid Reliability Studies

To address concerns whether there are any transient stability issues for the scenario without Diablo Canyon and SONGS as base-load generation, additional transient stability studies were performed for some of the most critical contingencies in the Western Interconnection system. The CPUC Commercial Interest (i.e., base case) portfolio was evaluated for the 2022 Summer Peak load conditions. In addition, a sensitivity evaluation with the 2022 Off-Peak load conditions was evaluated with the CPUC High Distributed Generation (High D.G.) portfolio. This sensitivity study was performed to check whether there would be adequate inertia in the system under the conditions studied in response to critical contingencies in the WECC system. As expected, the results for the 2022 Off-Peak load High D.G. study case indicated slower damping response, especially for some generating units in San Diego area, than in the summer peak case because of less generation inertia in the WECC system, but the results did not exhibit system wide transient stability concerns. The following tables provide summary of the transient study results. In addition, transient angular plots for several generators are provided for some of these critical contingencies are included in appendix E.

Table 3.5-13: Summary of transient stability study results for the 2022 Commercial Interest Summer Peak Load study case (no nuclear generation scenario)

	Contingency	Meeting WECC Criteria?	
		Transient Voltage	Transient Frequency
1	IPPDC Bi-pole	√	√
2	Midway-Vincent double line outage (N-2)	√	√
3	PDCI Bi-pole	√	√
4	Palo Verde G-2	√	√
5	Red Bluff – Devers double line outage (N-2)	√	√
6	Overlapping Sunrise and SWPL line outage (N-1-1)	√ *	√ *

Note:

*Meets WECC transient stability voltage and frequency criteria with proposed least-regret 2018 transmission mitigation plan without SONGS (2013 mitigation is also assumed to be in service).

Table 3.5-14: Summary of transient stability study results for the 2022 High D.G. Off-Peak Load study case (no nuclear generation scenario)

	Contingency	Meeting WECC Criteria?	
		Transient Voltage	Transient Frequency
1	IPPDC Bi-pole	√	√
2	Midway-Vincent double line outage (N-2)	√	√
3	PDCI Bi-pole	√	√
4	Palo Verde G-2	√	√
5	Red Bluff – Devers double line outage (N-2)	√	√
6	Overlapping Sunrise and SWPL line outage (N-1-1)	√ *	√ *

Note:

*Meets WECC transient stability voltage and frequency criteria with proposed least-regret 2018 transmission mitigation plan without SONGS (2013 mitigation is also assumed to be in service)

3.5.8 Sensitivity Analyses with CPUC High D.G. Portfolio for 2022 Summer Peak Load Conditions for LA Basin and San Diego LCR Areas

This section addresses the results of a sensitivity analyses based on the CPUC High D.G. portfolio for 2022 Summer Peak load conditions for the LA Basin and San Diego LCR areas. The ISO also has been requested by the state energy agencies (i.e., CEC and CPUC) as well as the California Air Resources Board (CARB) to perform additional sensitivity studies with incremental uncommitted energy efficiency (EE) beyond the committed portion that was included in the Commission's adopted demand forecast and potential incremental combined heat and power (CHP). These additional sensitivity analyses regarding uncommitted programs were requested by the state agencies in support of AB 1318 study-related works will be performed outside of this process and may be included in the final report, or addendum to the final report, depending on when it is available.

Sensitivity analyses were performed with the High D.G. portfolio for the 2022 Summer Peak power flow case to determine how much reduction of the thermal generation requirement, as identified for the CPUC Commercial Interest (base case) portfolio, would be achieved with a higher level of distributed solar PV in the LA Basin and San Diego LCR areas.

Post-transient voltage stability evaluation for the Category C contingency in San Diego area (i.e., N-1-1 of the Sunrise, followed by SWPL) was performed for the generation alternative with the highest new and replaced generation in the LA Basin (i.e., the 4,600 MW generation addition and replacement alternative in the LA Basin).

The amount of D.G. for the CPUC Commercial Interest and High D.G. portfolios for the 2022 Summer Peak case is summarized below.

Table 3.5-15: Distributed generation in 2022 Commercial Interest and High D.G. Summer Peak Case

	Commercial Interest		**High D.G.**	
Area	**Dispatched Capacity (MW)**	**Installed Capacity (MW)**	**Dispatched Capacity (MW)**	**Installed Capacity (MW)**
LA Basin LCR Area	243	486	769*	1,538
San Diego Sub-LCR Area	202*	404	245*	490

Notes:

*Dispatched capacity was derived by applying a 50 percent NQC factor provided by the CPUC for small solar PV technology

The assessment with the High D.G. portfolio resulted in a total new generation addition and replacement requirements of 4,112 MW in the LA Basin, representing a reduction of about 488 MW compared with the Commercial Interest portfolio. When compared with the Commercial Interest's D.G. amount in the LA Basin and San Diego areas, the High D.G. portfolio represents an increase of 569 MW of production from D.G. capacity. With a reduction of 488 MW of thermal generation requirements with the High D.G. portfolio, the results appear to indicate that for every MW of production from D.G. capacity in the studied area, it would reduce the amount of thermal generation by about 0.85 MW. In terms of installed capacity, the comparison ratio would be 1 MW D.G. to 0.43 MW of thermal generation.

The above evaluation is greatly dependent on the net qualifying capacity (NQC) conversion factor from the CPUC. A high NQC conversion factor helps in this case. Observations from the utilities, particularly in the northern area seems to indicate that at the time of peak load (i.e., close to 5 p.m.) the solar PV output would appear to be about 35 percent of its installed capacity. Further observations and evaluations would be needed to improve the conversion factor from installed capacity to net dependable capacity at peak loads for the renewable generation.

3.6 Review of Existing SPS

Within the ISO controlled grid there are a significant number of Special Protection Systems (SPS) in operation. These SPS are related to a wide variety of system operating conditions such as, bulk system performance requirements, local area performance requirements and generator interconnection. As a part of the 2012-2013 Transmission Planning Process (TPP), the ISO conducted an assessment of the existing SPS that are in operation in the ISO Controlled Grid. The objective of the SPS review was to assess the existing SPS that are in operation on the transmission system to ensure that they meet the current needs of the system and as we plan transmission development on the system. The following provides the steps taken in conducting this review of existing SPS.

- Document the list of existing SPS in the ISO controlled grid.
- Identify for each SPS the associated contingency, action initiated, load drop, generation drop, arming, complexity, security, consequences if fail to operate.
- Develop criteria for design and protection coordination review.
- Functional Review of existing SPS.
    - Is functionality current, and does the SPS meet current criteria?
    - Even if so, is the risk of system impact acceptable?

The review of the exiting SPS considered the performance, operation and design of the existing SPS on the system to determine if they need to be modified, removed or replaced due to:

- Planned transmission developments;
- Changes in transmission utilization; and/or
- Changes in risk tolerance.

The review of the existing SPS was done in two stages set out below and was performed under the planning paradigm to supplement the reliability assessment of the ISO controlled grid within the annual TPP:

- Stage-1: Review (Documentation)
- Stage 2: Review (Functional Review)

As part of the annual reliability assessment in the TPP, the ISO performed Stage-1 and Stage-2 reviews for all SPS in each local area. The review of the existing SPS is to develop recommendations of actions, if any, that are required to maintain reliability of the ISO controlled grid and coordination with adjacent interconnected systems.

- leaving the SPS in place as is;
- removing the SPS from service;
- modifying functionality of the existing SPS; or
- replacing the existing SPS with a transmission capital solution.

Table 3.6-1 summarizes the of recommendations for each SPS reviewed as a part of this assessment

Table 3.6-1: Summary of recommendations for each SPS

SPS Name	PTO	Area	Recommendation
Mesa and Santa Maria Undervoltage SPS	PG&E	Central Coast / Los Padres	The need for these two interim SPS solutions prior to the implementation of the approved *New Andrew Project* in 2019 is necessary in order to avoid severe to total voltage collapse conditions in the Mesa 115 kV system under the specified Category C contingency conditions.
Divide Undervoltage SPS	PG&E	Central Coast / Los Padres	The need for this interim SPS solution prior to the implementation of a more permanent solution is necessary in order to avoid severe to total local area-wide voltage collapse conditions in the Divide-Cabrillo-Sisquoc area under the specified Category C contingency conditions.
Temblor-San Luis Obispo 115 kV Overload Scheme (TBD)	PG&E	Central Coast / Los Padres	The need for this SPS is necessary in order to avoid overloading the Temblor-San Luis Obispo 115 kV Line.
COI RAS	PG&E	Bulk	The need for this SPS in future years is evident in order to avoid overloading of facilities in Northern California and Northwest under N-2 contingency conditions and to avoid system collapse. Under some operating conditions, such as low COI and PDCI flow or flow in the opposite (South-to-North) direction, the COI RAS is not required. Under high south-to-north flow, the COI South-to-North RAS is needed.
Colusa SPS	PG&E	Bulk	Colusa SPS may be needed if new renewable generation projects develop in the North Valley area. This SPS may need to be modified to also protect Round Mountain 500/230 kV transformer for the Captain Jack-Olinda outage and for an outage of the Olinda 500/230 kV transformer. It is recommended to leave the SPS in place and to consider its modification if the new generation in the area develops.
Diablo Canyon SPS	PG&E	Bulk	The need for this SPS is clearly evident and hence the recommendation is to have this SPS in-service all the time.

SPS Name	PTO	Area	Recommendation
Gates 500/230 kV Bank #11 SPS	PG&E	Bulk	The need for this SPS is evident and hence the recommendation is to leave it in place.
Midway 500/230 kV Transformer Overload SPS	PG&E	Bulk	The need for this SPS is not clear and hence the recommendation to study other system conditions for which the SPS may be needed. If the SPS appears not to be needed, the recommendation will be to remove it from service.
Path 15 IRAS	PG&E	Bulk	The need for this RAS in future years is evident in order to avoid overloading of PG&E transmission facilities under N-2 contingency conditions. However, it was observed that the RAS may not be required under some operating conditions when the flow on Path 15 is low. Since the Path 15 IRAS is armed according to the nomogram and it was shown to be needed it is recommended to leave the RAS in place as it is.
Path 26 RAS North to South	PG&E	Bulk	The need for the Path 26 RAS in the current and future years is evident in order to avoid overloading of the Midway-Whirlwind 500 kV line under N-2 contingency condition. However, it was observed that the SPS may not be required under all operating conditions; it is required only on peak with high north-to-south Path 26 flow. The RAS is armed according to nomograms; therefore risk of unintended operation is low. It is recommended to leave this RAS in place as it is.
Path 26 RAS South to North	PG&E	Bulk	The need for this RAS in the current and future years is evident in order to avoid overloading of the Midway-Whirlwind 500 kV line under N-2 contingency conditions with high south-to-north flow on Path 26. However, the 2012-2013 Transmission Plan studies did not show the need for this RAS because the level of Path 26 flow was not that high. The RAS may still be needed if the flow on Path 26 is higher, which may be the case in the future when more renewable generation will develop in Southern California. Considering that the risk on unintended consequences of the Path 26 RAS is low and it is armed according to the Path 26 nomogram, it is recommended to leave the Path 26 South-to-North RAS in place as it is.

SPS Name	PTO	Area	Recommendation
Table Mt 500/230 kV Bank #1 SPS	PG&E	Bulk	Even if the need for this SPS under low load and high generation conditions is evident, its operation has unintended consequences of high transient frequency dip which is a violation of the WECC criteria. In addition, the SPS is cut-in manually which cannot prevent for human errors that may result in the SPS operating when it is not required or not operating when it is required. It is recommended to re-evaluate the SPS and consider measures other than tripping Hyatt and Thermalito generation. Possible solutions may be upgrades of the overloaded transmission lines or installation of Distributed FACTS devices to re-distribute power flow and mitigate the overloads. Then, the SPS will not be needed. The Distributed FACTS devices may also help to mitigate overloads in the Table Mountain-Rio Oso area that may occur with a 500 kV double outage south of Table Mountain and eliminate the need for tripping Feather River generation with this contingency. Another solution may be to trip generation other than Hyatt and Thermalito by the SPS to avoid violations of the WECC transient frequency criteria.
Drum (Sierra Pacific) Overload Scheme (Path 24)	PG&E	Central Valley	Although the need for this SPS is not evident based on the results of the 2012-2013 reliability assessment, this SPS could still be needed to protect Drum – Rio Oso #1, Drum – Rio Oso #2, Gold Hill – Placer #1 and Gold Hill – Placer #2 115kV lines during high export to Sierra Pacific and low Drum area generation conditions. More studies are needed to see if there are credible system conditions in Sierra Pacific system that could result in high import into Sierra Pacific given that the network topology changed from the time this SPS was originally designed. As such, the recommendation for this SPS is to leave it in place as is.
Stanislaus – Manteca 115 kV Line Load Limit Scheme	PG&E	Central Valley	The need for this SPS is evident in order to avoid overloading of the Stanislaus-Manteca 115 kV lines under Category C contingency conditions. As such, the recommendation for this SPS is to leave it in place as is.

SPS Name	PTO	Area	Recommendation
Vaca-Suisun 115 kV Lines Thermal Overload Scheme	PG&E	Central Valley	The need for this SPS is evident in order to avoid overloading of the Vaca-Suisun-Jameson 115 kV line under N-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is.
West Sacramento 115 kV Overload Scheme	PG&E	Central Valley	Although a need for this SPS was not found in any years and scenarios studied for the N-1 contingency condition that this SPS was originally designed for, this SPS could be used to some extent to protect the 115 kV lines in the area under some Category C events until the Vaca-Davis conversion project is implemented. As such, the recommendation for this SPS is to leave it in place as is until the project gets implemented and consider taking this SPS out of service following the transmission upgrade project implementation.
West Sacramento Double Line Outage Load Shedding SPS Scheme	PG&E	Central Valley	The need for this SPS is evident until the Vaca-Davis 115 kV voltage conversion project is implemented. However, the SPS, as designed, is not sufficient to mitigate overload on the Brighton-Davis 115 kV line. As such, the recommendation for this SPS is to modify the design to include tripping of third distribution transformer as well at West Sacramento substation and leave it in place until the transmission upgrade project gets implemented.
Ashlan SPS	PG&E	Greater Fresno Area	The need for this SPS in future years should not be needed once the Gregg-Ashlan 230kV and Herndon-Ashlan 230kV lines are reconductored. Mis-operation of this SPS only causes Ashlan to be single sourced with no other consequences. Keep SPS in place until completion of project to reconductor Gregg-Ashlan 230kV and Herndon-Ashlan 230kV lines.

SPS Name	PTO	Area	Recommendation
Atwater SPS	PG&E	Greater Fresno Area	The need for this SPS is evident and hence the recommendation is to leave it in place until completion of the Wilson 115kV Area Reinforcement project. It is also recommended that the set point to trip Atwater-El Capitan 115kV be reviewed, as it seems too low to prevent exceeding Emergency ratings for the lines noted above.
Gates Bank 11 SPS	PG&E	Greater Fresno Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Helms HTT RAS	PG&E	Greater Fresno Area	The need for this SPS is evident and hence the recommendation is to leave it in place. Further review is necessary to determine why the T-129 PI screen and results above differ. New projects included in the planning base cases may account for the shift.
Helms RAS	PG&E	Greater Fresno Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Henrietta RAS	PG&E	Greater Fresno Area	The need for this SPS is not completely evident and further study is needed. • Can LTCs be locked at Henrietta? • Capital transmission solution to eliminate 230kV taps at Henrietta?
Herndon-Bullard SPS	PG&E	Greater Fresno Area	Per email from ISO and PG&E OE, this SPS was removed when the limiting switches were upgraded.
Kerckhoff 2 RAS	PG&E	Greater Fresno Area	This SPS should be reviewed by protection, since the description says that Kerckhoff #1-Kerckhoff #2 115kV (CB142) is one of the monitored elements. This line is a radial gen-tie between Kerckhoff #1 & Kerckhoff #2. It should probably monitor CB182, which is the Chowchilla-Kerckhoff 2 115kV line. Recommendation is keep this SPS in place to avoid reducing generation by control room personnel during spill conditions.

SPS Name	PTO	Area	Recommendation
Reedley SPS	PG&E	Greater Fresno Area	This SPS needs to be reviewed/updated by Operations Engineering to include the new Sanger-Reedley 115kV line that was converted from 70kV to 115kV in 2012. Substation at Reedley has been sufficiently upgraded that the CB numbers in the SPS document no longer make sense when looking at the one-line.
Metcalf SPS	PG&E	Greater Bay Area	The need for this SPS is not evident based on the conditions studied in the planning assessment. The recommendation is to leave it in place normally cut-out until further study is conducted.
SF RAS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
South of San Mateo SPS	PG&E	Greater Bay Area	The need is evident until the capacity project is complete.
Metcalf-Monta Vista 230kV OL SPS	PG&E	Greater Bay Area	The need for this SPS is not evident at the time and hence the recommendation is to leave it in place until further study is conducted.
San Mateo-Bay Meadows 115kV line OL	PG&E	Greater Bay Area	The need for this SPS is not evident at the time and hence the recommendation is to leave it in place until further study is conducted.
Moraga-Oakland J 115kV line OL RAS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Grant 115kV OL SPS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Oakland 115 kV C-X Cable OL RAS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Oakland 115kV D-L Cable OL RAS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Sobrante-Standard Oil #1 & #2-115kV line	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Gilroy SPS	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.

SPS Name	PTO	Area	Recommendation
Transbay Cable Run Back Scheme	PG&E	Greater Bay Area	The need for this SPS is evident and hence the recommendation is to leave it in place.
Humboldt – Trinity 115kV Thermal Overload Scheme	PG&E	Humboldt	Although the need for this SPS does not exist anymore based on the conditions studied in the planning assessment of the Humboldt system, the SPS can be left in service to protect the Humboldt – Trinity 115 kV line against thermal overloads for any system conditions that are not covered under the planning studies.
Caribou Generation 230 kV SPS Scheme #1	PG&E	North Valley	The need for this SPS is evident in order to avoid overloading of the Caribou-Palermo 115 kV line under N-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is.
Caribou Generation 230 kV SPS Scheme #2	PG&E	North Valley	The need for this SPS is evident in order to avoid instability in Caribou area under N-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is.
Cascade Thermal Overload Scheme	PG&E	North Valley	The need for this SPS is evident in order to avoid overloading of the Cascade-Benton-Deschute 60 kV line under N-1-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is.
Hatchet Ridge Thermal Overload Scheme	PG&E	North Valley	The need for this SPS is evident in order to avoid overloading of the Pit #1-Cottonwood 230 kV line under N-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is.
Coleman Thermal Overload Scheme	PG&E	North Valley	The need for this SPS is evident until the New 230/60 kV substation and new 60 kV lines to Red Bluff and Tyler substations project is implemented in order to avoid overloading of the Coleman-Red Bluff 60 kV line under N-1 contingency condition. As such, the recommendation for this SPS is to leave it in place as is until the project gets implemented and consider taking this SPS out of service following the project implementation.
Antelope-RAS	SCE	Antelope-Bailey	The recommendation for this SPS is to remove the SPS from service.

SPS Name	PTO	Area	Recommendation
Big Creek / San Joaquin Valley RAS	SCE	Big Creek Corridor	The need for this SPS is evident. The current SPS needs modification due to Cross-Valley loop in project. Hence the recommendation is to modify existing SPS.
Bishop RAS	SCE	North of Lugo	The need for this SPS is evident and hence the recommendation is to leave it in place.
High Desert Power Project RAS	SCE	North of Lugo	The need for this SPS is evident for Lugo-Victor No.1 and No.2 220 kV and for Lugo 1AA and 2AA Banks 500/220 kV contingency and hence the recommendation is to leave it in place. For Lugo-Victor No.1 or No.2 220 kV and Lugo 1AA or 2AA Banks 500/220 kV outage; the RAS need was not identified with the given system conditions. Additional study needs to be performed on the cases to verify the need of RAS for Lugo-Victor No.1 or No.2 220 kV and Lugo 1AA or 2AA Banks 500/220 kV contingency.
Kramer RAS	SCE	North of Lugo	The need for this SPS is evident for monitored outages except for Kramer-Lugo No.1 or No.2 220 kV. Also, the current SPS needs modification to maintain stability in the system. Hence the recommendation is to modify existing SPS. For Kramer-Lugo No.1 or No.2 220 kV outage; the RAS need was not identified with the given system conditions. Additional study needs to be performed on the cases to verify the need of RAS for Kramer-Lugo No.1 or No.2 220 kV contingency.
Lancaster N-2 Line Loss Tripping Scheme	SCE	Antelope-Bailey	The need for this SPS is evident and hence the recommendation is to leave it in place.
Palmdale N-2 Line Loss Tripping Scheme	SCE	Antelope-Bailey	The need for this SPS is evident and hence the recommendation is to leave it in place.
Pastoria Energy Facility Existing RAS	SCE	Antelope-Bailey	The need for this SPS is evident and hence the recommendation is to leave it in place.
Reliant Energy Cool Water Stability Tripping Scheme	SCE	North of Lugo	The need for this SPS is evident. The current SPS needs modification to maintain stability in the system. Hence the recommendation is to modify existing SPS.

SPS Name	PTO	Area	Recommendation
West-of-Devers Remedial Action Scheme	SCE	Eastern Area	The WOD RAS was installed as a temporary solution until re-conductoring of the WOD 230 kV lines can be completed. The in-service date of the WOD upgrades is estimated to be in the year 2019. Modifications are needed to this SPS to accommodate new transmission and generation coming on-line prior to 2019.
Blythe Energy RAS - Thermal Overload Scheme	SCE	Eastern Area	The need for this SPS is evident and hence the recommendation is to leave it in place. Operating procedures and flow limits need to be updated to ensure compatibility with the SPS.
Blythe Energy RAS – Low Voltage Scheme	SCE	Eastern Area	The ISO recommends this SPS be removed from service. Flow limits need to be implemented to ensure area voltages and voltage deviations are within limits following an outage of Palo Verde–Colorado River 500 kV line.
Eagle Mountain Thermal Overload Scheme	SCE	Eastern Area	The ISO recommends this SPS be removed from service once flow limits are implemented to ensure the line protected by the SPS remains within its thermal rating following an outage of Palo Verde–Colorado River 500 kV line.
El Nido N-2 Remedial Action Scheme	SCE	Metro Area	The need for this RAS is evident in order to avoid overloading of the remaining 230 kV line under loss of any two of the three monitored 230 kV lines for the Category D contingency of G-1/N-2. It is recommended to leave the RAS in place.
Mountainview Power Project Remedial Action Scheme	SCE	Metro Area	The need for this RAS is evident in 2014 and 2017 under high output of the Mountainview Power Project and low load at the San Bernardino and El Casco Substations. However, the study did not identify the need of the RAS after the West-of-Devers Upgrade Project (re-conductoring of the West-of-Devers 230 kV lines) is completed. This is estimated to be sometime in 2018. In addition, it is recommended that the RAS settings (e.g. arming threshold) be reviewed before the Interim West-of-Devers Project (installing series reactors on the West-of-Devers 230 kV lines) is in service.

SPS Name	PTO	Area	Recommendation
South of Lugo N-2 Remedial Action Scheme	SCE	Metro Area	The need for this RAS is evident before the new Mira Loma-Vincent 500 kV Line is in service. However, the study did not identify the need of the RAS after the new Mira Loma-Vincent 500 kV Line is in service. It is recommended to keep the RAS normally disabled after the Mira Loma-Vincent 500 kV Line is in service and to enable it under critical system conditions. It is also recommended that SCE review and update (if needed) the RAS settings before each of the following transmission upgrades is in place. • Segments of Tehachapi Renewable Transmission Project (TRTP) in the LA Basin area • Devers-Palo Verde No.2 Project (California portion) • Interim West-of-Devers Project • West-of-Devers Upgrade Project
Mira Loma Low Voltage Load Shedding	SCE	Metro Area	The need for this RAS is evident. It is recommended that the SPS be reviewed and updated before each of the following transmission upgrades are in place. • Segments of Tehachapi Renewable Transmission Project (TRTP) in the LA Basin area • Devers-Palo Verde No.2 Project (California portion) • Interim West-of-Devers Project • West-of-Devers Upgrade Project
Santiago N-2 Remedial Action Scheme	SCE	Metro Area	The need for this RAS is evident under stressed system conditions (e.g. the Category D contingency of N-2 in addition to a forced outage of Huntington Beach Units 1 & 2). It is recommended that the arming threshold of the RAS be reviewed and updated before and after the following upgrades: (a) Barre – Ellis 230 kV Reconfiguration (to four 230 kV lines) and (b) Johanna & Santiago 230kV Capacitor Banks.

<table>
<tr><th>SPS Name</th><th>PTO</th><th>Area</th><th>Recommendation</th></tr>
<tr><td>Valley Direct Load Trip Remedial Action Scheme</td><td>SCE</td><td>Metro Area</td><td>The need for the VDLT RAS is not evident in the study. The following major system reinforcements were or will be in place to improve voltage stability in the Valley area after the VDLT RAS was in service.
Valley No.5 and No.6 500 kV shunt capacitors (already in service)
Inland Empire Energy Center (IEEC) (already in service)
Devers-Valley No.2 500 kV Line (estimated in-service date: 2013)
It is recommended to normally disable the RAS and to enable it under critical system conditions. In addition, it is needed to modify the monitored transmission lines after the Alberhill Substation is in service.</td></tr>
<tr><td>230kV Otay Mesa Energy Center Generation SPS</td><td>SDG&E</td><td>SDG&E</td><td>The need for this SPS in future years is evident in order to avoid overloading of facilities in CFE under N-2 contingency condition.</td></tr>
<tr><td>ML (Miguel) Bank 80/81 Overload SPS</td><td>SDG&E</td><td>SDG&E</td><td>The need for this SPS is evident under an outage of TL50003 line and hence the recommendation is to activate it when TL5003 is out-of-service.</td></tr>
<tr><td>CFE SPS to protect lines from La Rosita to Tijuana</td><td>SDG&E</td><td>SDG&E</td><td>The need for this SPS in future years is evident in order to avoid overloading of facilities in CFE under N-2 contingency (TL50001 and TL50003) and any other conditions which can result in overloads on CFE internal system.</td></tr>
<tr><td>TL 50001 IV Generator SPS</td><td>SDG&E</td><td>SDG&E</td><td>The need for this SPS is evident under an outage of TL50003 line and hence the recommendation is to activate it when TL5003 is out-of-service.</td></tr>
<tr><td>Path 44 South of SONGS Safety Net</td><td>SDG&E</td><td>SDG&E</td><td>This scheme would prevent voltage collapse caused by extreme (Category D) contingencies by shedding up to 800 MW load. The need for such a scheme is evident in all study years.</td></tr>
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Chapter 4

4 Policy-Driven Need Assessment

4.1 Study Assumptions and Methodology

4.1.1 33% RPS Portfolios

The CPUC and the CEC sent a letter on March 12, 2012 formally recommending the renewable portfolios for use in the ISO 2012-2013 transmission planning process. The portfolios were updated in a March 23, 2012 letter. At the April 2, 2012, transmission planning stakeholder meeting, the CPUC and CEC presented four proposed RPS portfolios: Commercial Interest, Cost Constrained, Environmentally Constrained and High DG. In response to stakeholders comments the two commissions in the letter to the ISO dated May 16, 2012, revised the portfolios and recommended that the ISO study the Commercial Interest portfolio 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 Tariff section 24.4.6.6.

The proposed renewable portfolios, as modified by the ISO, were studied in the policy-driven transmission planning assessments on the ISO controlled grid.

The installed capacity and energy per year of each portfolio by location and technology are shown in the following tables.

Table 4.1-1: Commercial interest portfolio – base portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Baja								100	100
Carrizo South					900				900
Central Valley North		63			145				208
DG-NCA Muni						42			42
DG-SCA Muni						112			112
Distributed Solar - PG&E						1,005			1,005
Distributed Solar - SCE						487			487
Distributed Solar - SDGE						405			405
El Dorado					250		500		750
Imperial	15		474		1,356	30		265	2,140
Kramer			64		320	74	250	56	765
Los Banos					370				370
Merced	5				60				65
Mountain Pass					300		365		665
Nevada C			142						142
NonCREZ	104	7	15		56	72		3	256
Northwest								330	330
Palm Springs						16		182	198
Riverside East					800	5	701		1,506
Round Mountain									0
San Bernardino - Lucerne					45	19		42	106
San Diego South								384	384
Solano	3				28			474	505
Tehachapi	10				1,255	142		1,988	3,395
Westlands		49			1,293	158			1,500
Grand Total	**136**	**119**	**695**	**0**	**7,728**	**2,567**	**1,816**	**4,274**	**17,335**

Table 4.1-2: Cost constrained portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Baja									0
Carrizo South					900				900
Central Valley North		63			235				298
DG-NCA Muni									0
DG-SCA Muni									0
Distributed Solar - PG&E						1,047			1,047
Distributed Solar - SCE						599			599
Distributed Solar - SDGE						405			405
El Dorado					250				250
Imperial	15		725		370	30			1,140
Kramer						20	42		62
Los Banos									0
Merced	5				15				20
Mountain Pass					680		365		1,045
Nevada C			142						142
NonCREZ	110	7	15		246	22		143	542
Northwest								330	330
Palm Springs						6		182	188
Riverside East					1,467		400		1,867
Round Mountain									0
San Bernardino - Lucerne					219			52	271
San Diego South								384	384
Solano	3				28			474	505
Tehachapi	10				2,501	57		1,998	4,566
Westlands	5	49			1,366	80			1,500
Grand Total	**147**	**119**	**882**	**0**	**8,828**	**2,266**	**807**	**4,013**	**17,061**

Table 4.1-3: Environmentally constrained portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Baja									0
Carrizo South					900				900
Central Valley North		63			235				298
DG-NCA Muni									0
DG-SCA Muni									0
Distributed Solar - PG&E						1,837			1,837
Distributed Solar - SCE						1,978			1,978
Distributed Solar - SDGE						426			426
El Dorado									0
Imperial	15		474		1,356	30		265	2,140
Kramer						2	62		64
Los Banos					370				370
Merced	5				60				65
Mountain Pass							365		365
Nevada C			116						116
NonCREZ	110	135	15	21	56	74		3	413
Northwest								290	290
Palm Springs						16		182	198
Riverside East					959	5	400		1,364
Round Mountain		34							34
San Bernardino - Lucerne	7				45	14		42	108
San Diego South								384	384
Solano	3				28			474	505
Tehachapi	10				1,255	122		1,988	3,375
Westlands		49			1,162	289			1,500
Grand Total	**149**	**281**	**605**	**21**	**6,975**	**4,792**	**827**	**4,078**	**17,728**

Table 4.1-4: High DG portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Baja									0
Carrizo South					900				900
Central Valley North		63			135				198
DG-NCA Muni						50			50
DG-SCA Muni						231			231
Distributed Solar - PG&E						3,591			3,591
Distributed Solar - SCE						2,995			2,995
Distributed Solar - SDGE						490			490
El Dorado					250		500		750
Imperial	15		725		370	30			1,140
Kramer						20	42		62
Los Banos									0
Merced	5				15				20
Mountain Pass					300		365		665
Nevada C			142						142
NonCREZ	104	7	15		56	22		3	206
Northwest								290	290
Palm Springs						6		77	83
Riverside East					1,234		276		1,510
Round Mountain									0
San Bernardino - Lucerne					145			42	187
San Diego South									0
Solano	3				28			474	505
Tehachapi	10				1,302	57		1,060	2,429
Westlands	0	49			861	80			990
Grand Total	**136**	**119**	**882**	**0**	**6,146**	**7,572**	**1,183**	**2,396**	**18,434**

4.1.2 Assessment Methods for Policy-Driven Transmission Planning

4.1.2.1 Power Flow and Stability Assessment

NERC and WECC reliability standards and ISO Planning Standards were followed in the policy-driven transmission planning study, which are described in chapter 2 of this plan. All required assessments, including power flow contingency analysis, post transient voltage stability analysis, and transient stability analysis, were performed as well. The contingencies that were 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 assessment. In all cases, curtailing renewable generation following the first contingency can mitigate the impact of renewable generation flow prior to the second contingency. Given high transmission equipment availability, 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 excessive renewable generation curtailments were assessed. Outages that potentially impact system-wide stability were extensively simulated and investigated. 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 performance deficiencies identified in the studies and the plans were investigated to verify their effectiveness. Multiple alternatives were compared to identify the preferred mitigations. If a concern was identified in the ISO Annual Reliability Assessment for NERC Compliance but was aggravated by 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 original identified reliability mitigation or a different alternative, was then included as part of the comprehensive plan.

4.1.2.2 Deliverability Assessment

Deliverability of the renewable generators studied in the RPS portfolios was assessed following the ISO Generator Deliverability Assessment Methodology. Necessary transmission upgrades were proposed to make all renewable generation in the portfolios deliverable. If there is any identified upgrade in the deliverability assessment, it is included in the final mitigation plans.

The details of the deliverability assessment are discussed in section 4.2.

4.1.2.3 Production Cost Simulation

The production cost simulation results were used to identify the generation dispatch and path flow patterns in the 2022 study year after the renewable portfolios were modeled in the system. Generation exports from renewable generation study areas were monitored as well as major transfer path flows. This information was used to identify high transmission system usage patterns during peak and off-peak load conditions. Selected high transmission usage patterns were used as reference in power flow and stability base case development. 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 2022 load forecast as well. ABB GridView was used to perform the production cost simulations in the policy-driven transmission planning study.

The details of this production cost simulation analysis are discussed in chapter 5.

4.1.3 Base Case Assumptions

4.1.3.1 Starting Base Cases Comparison of All portfolios

The consolidated peak and off-peak base cases for 2022 in the ISO Annual Reliability Assessment for NERC Compliance were used as the starting points for developing the base cases used in the policy-driven transmission planning study.

4.1.3.2 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 the RPS portfolios to identify 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 May 2012 was used. A typical off-peak 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 as show in Table 4.1-5.

Table 4.1-5: Load condition by areas

Area in Basecases	**1-in-5 coincident peak load (MW)**
Area 30 (PG&E)	31,420
Area 24 (SCE)	26,536
Area 22 (SDG&E)	5,823

4.1.3.3 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); and
- Sentinel Peaker Project (850 MW).

Resources were not modeled in the base cases if their retirement has been officially announced. The once-through cooling units were modeled in the base cases consistent with the OTC replacement need amounts identified in the OTC study performed by the ISO in 2011-2012 planning cycle.

4.1.3.4 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 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 by comparing portfolios discussed in section 4.1 and previous generator interconnection studies results.

Table 4.1-6 and

Table 4.1-7 summarize the transmission projects with CPUC approval or in executed LGIAs that are modeled in the policy-driven transmission planning base cases. The details of these transmission projects are described in the report sections focused on the areas of the ISO system where the projects are modeled.

Table 4.1-6: 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	NOC effective
Eldorado-Ivanpah	LGIA	Approved
Valley-Colorado River	Approved	Approved
West of Devers Upgrade	LGIA	not yet filed
Tehachapi	Approved	Approved
South of Contra Costa reconductoring	LGIA	not yet filed
Borden-Gregg 230 kV line reconductoring	LGIA	not yet filed
Mirage-Devers 230 kV lines upgrade	Approved	not yet filed
Whirlwind #2 and #3 transformers	LGIA	Not applicable
Imperial #3 transformer	LGIA	Not applicable
Humboldt 60 kV upgrades	LGIA	not yet filed

Table 4.1-7: 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-Highline and Imperial Valley-Dixie 230 kV lines	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 4.1-8 and for interconnecting new generation projects that have executed LGIA. These substations are listed in the table below.

Table 4.1-8: 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	For interconnection new resources; Lugo – Pisgah 230 KV #1 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

4.1.4 Power Flow and Stability Base Case Development

4.1.4.1 Modeling Renewable Portfolio

4.1.4.1.1 Power Flow Model and Reactive Power Capability

As discussed in section 4.1.1, the CPUC and CEC's renewable portfolios were used to represent RPS portfolios in the policy-driven transmission planning study. The commissions have assigned renewable resources by technology to geographic areas, including CREZs and locations of non-CREZ areas, and specific substations for some distributed generation resources. Based on the general locations provided, the ISO represented renewable resources in the power flow model based on information from generator interconnection studies performed by the ISO and utilities. The objective of modeling generation projects this way is not meant to endorse any particular generation project, but rather to streamline the transmission analysis.

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 was used that matches the capacity as listed in the portfolios. When an equivalent model was used for large scale wind turbine or solar PV generation, it was assumed that the generation could regulate bus voltage within a power factor range of 0.95 lagging to leading. The unity power factor was assumed for solar PV distributed generation. For all other new generation modeled, typical data was used in the equivalent model with a power factor range of 0.90 lagging and 0.95 leading.

4.1.4.1.2 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 used.

If dynamic models were not available, then 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 and governor models. For wind turbine and PV solar generators, generic GE Positive Sequence Load Flow Software models were used. In this study, Type 3 wind turbine generator model for doubly fed induction generators 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 were set such that the generators have adequate low voltage ride through and low frequency ride through capability.

4.1.4.2 Generation Dispatch and Path Flow in Base Cases

Power flow and stability studies are normally based on the generation dispatch assumptions that are agreed upon using historical data and engineering judgment. Yet, as the system approaches the 33 percent RPS, generation dispatch and power flow patterns will substantially change. 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 with the results used as reference data to predict future dispatch and flow patterns.

Certain hours that represent stressed patterns of path flows in the 2022 study year were selected from the production cost simulation results with the objective to study a reasonable upper boundary on stressed system conditions. The following three critical factors were considered in selecting the stressed patterns:

- renewable generation output system wide and within renewable study areas;
- power flow on the major transfer paths in California; and
- load level.

For example, hours that were selected for reference purposes were time frames during which there were near maximum renewable generation output within key study areas (e.g., Tehachapi, Riverside, Imperial, Fresno, etc.) and near maximum transfers across major ISO transmission paths during peak hours or off-peak hours.

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 production cost simulation and the power flow and stability assessments, as well as the fact that the production cost simulation is based on the 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.

4.1.5 Base Cases and Scenarios for Power Flow and Stability Assessments

Multiple scenarios were studied for each renewable portfolio 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 the table below. Because the objective is to study stressed cases with high renewable production levels, the off-peak scenarios studied represent low load weekend daytime hours with high solar production.

Table 4.1-9: Renewable dispatch and path flow patterns by portfolios

Portfolio	Load scenario	New renewable output (MW)	Path 49	Path 26	Path 15	Path 66	Path 65
Commercial Interest	Peak	10,439	5,375	660	2,260	4,110	3,087
Commercial Interest	Off peak	13,507	2,350	-2943	4,651	-2,055	0
Cost Constrained	Peak	10,226	5,404	585	2,274	4,120	3,084
Cost Constrained	Off peak	13,495	2,368	-2,959	4,166	-1,873	0
Environmentally Constrained	Peak	10,636	5,437	223	2,746	4,195	3,096
Environmentally Constrained	Off peak	13,502	2,372	-2,999	4,262	-2,299	0
High DG	Off peak	13,940	-91	1,451	367	1,456	0

4.1.6 Testing Deliverability for RPS

An assessment was performed to verify the deliverability of the renewable resources modeled in the base portfolio f

or resource adequacy (RA) 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;
- test the deliverability of the new renewable resources in the base portfolio located within the ISO balancing authority; and
- identify network upgrades needed to support full deliverability of the new renewable resources and renewable resources in the portfolio utilizing the expanded MIC.

4.1.6.1 Deliverability Assessment Methodology

The assessment was performed following the on-peak Deliverability Assessment methodology . The main deliverability assessment steps are described below.

4.1.6.2 Deliverability Assessment Assumptions and Base Case

A master base case was developed for the on-peak deliverability assessment that modeled all the generating resources in the base portfolio. Key assumptions of the deliverability assessment 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 for the ISO balancing authority area load was modeled in the base case. Non-pump load was the 1-in-5 peak load level for ISO. Pump load was dispatched within expected range for summer peak load hours.

Generation capacity (Pmax) in the base case

The most recent summer peak NQC was used as Pmax for existing thermal generating units. For new thermal generating units, Pmax was the installed capacity. Wind and solar generation Pmax data were set to 20 percent or 50 percent exceedance production level during summer peak load hours. If the study identified 20 or more non-wind generation units contributing to a deliverability constraint, both wind and solar generations were assessed for maximum output of 50 percent exceedance production level for the deliverability constraint; otherwise up to a 20 percent exceedance production level was assessed.

Table 4.1-10: Wind and solar generation exceedance production levels (% of installed capacity) in deliverability assessment

Type	20% Exceedance		50% Exceedance	
	Northern California	Southern California	Northern California	Southern California
Wind	51%	64%	28%	40%
Solar	100%	100%	85%	85%

Initial Generation Dispatch

All the existing generators were dispatched at 80 percent to 92 percent of the capacity. The new generators were dispatched up to 80 percent of the capacity to balance load and maintain expected imports.

Import Levels

Imports are modeled at the maximum summer peak simultaneous historical level by branch group. The historically unused existing transmission contracts (ETCs) 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. Table 4.1-11 shows the import megawatt amount modeled on the given branch groups.

Table 4.1-11: Deliverability assessment import target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville-BG	N-S	1,432	141
COI_BG	N-S	3,770	548
BLYTHE_BG	E-W	45	0
CASCADE_BG	N-S	36	0
CFE_BG	S-N	-119	0
ELDORADO_MSL	E-W	1,213	0
IID-SCE_BG	E-W	1,500	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-38	0
MCCULLGH_MSL	E-W	7	316
MEAD_MSL	E-W	938	455
NGILABK4_BG	E-W	-131	168
NOB_BG	N-S	1,208	0
PALOVRDE_MSL	E-W	2,872	168
PARKER_BG	E-W	126	28
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	6	0
SYLMAR-AC_MSL	E-W	-164	368
Total		**12,599**	**2,192**

4.1.6.3 Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability and 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 DFAX region. These are expressed as follows:

- Distribution factor (DFAX) = (change in flow on the analyzed facility / change in output of the generating unit) *100 percent

  or

- Flow impact = (DFAX * capacity / applicable rating of the analyzed facility) *100 percent; where NQC represents the net qualifying capacity of a generating unit

Load flow simulations were performed, which studied the worst-case combination of generator output within each 5 percent circle.

4.1.6.4 Verifying and refining the analysis using AC power flow tool

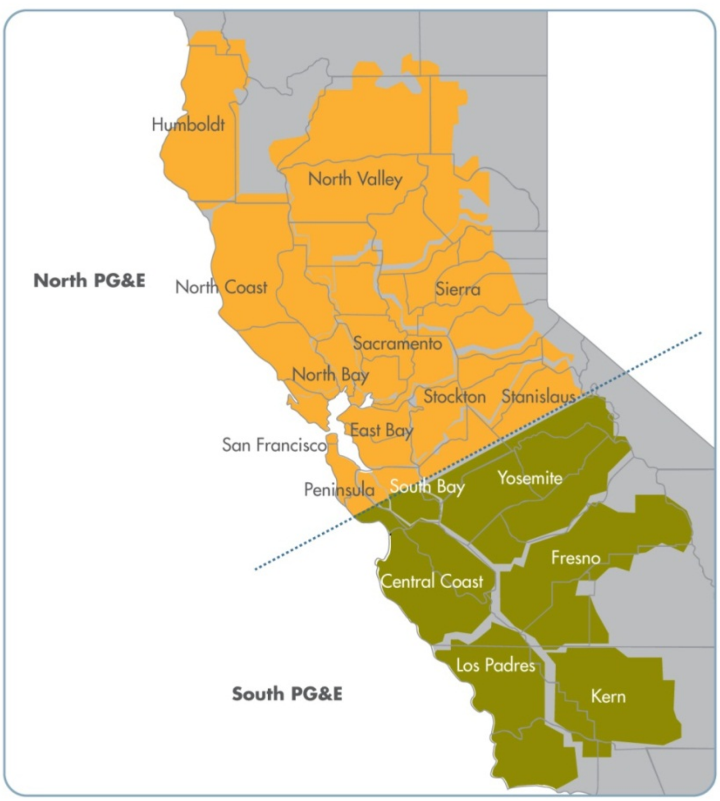
The outputs of capacity units in the 5 percent circle were increased starting with units with the largest impact on the transmission facility. No more than 20 units were increased to their maximum output. In addition, generation increases were limited to 1,500 MW or less. All remaining generation within the ISO balancing authority area 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 contributions to adder was negative, the impact was set to zero and the flow on the analyzed facility without applying the adder was reported.

4.2 Policy-Driven Assessment in PG&E Area

The renewable generation scenarios assessment included the four renewable portfolios evaluations described earlier: Cost Constrained, Commercial Interest, Environmentally Consrained and High DG. 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 2022 peak and off-peak conditions. For the bulk system and the southern areas of PG&E, the off-peak studies modeled the Helms Pump Storage Power Plant operating in the pumping modewith two units. The division of the PG&E area into northern and southern regions is shown in the figure below.

Figure 4.2:1: Northern and Southern areas of the PG&E system



4.2.1 Northern PG&E Policy-Driven Powerflow and Stability Assessment Results and Mitigations

The Northern PG&E area studies included assumptions on the renewable resources summarized in Table 4.2-1 and shows how these resources were distributed among the CREZs.

Table 4.2-1: 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
Commercial Interest	1,052	696	690
Cost Constrained	1,413	536	1,040
Environmentally Constrained	1,823	1,008	1,318
High DG	3,146	N/A	2,427

Table 4.2-2: North PG&E Renewable Generation by zones modeled to meet 33 percent RPS net short

Zones	Commercial Interest	Cost Constrained	Environmentally Constrained	High DG
Round Mountain	0	0	34	0
Solano	505	505	505	505
Central Valley North	207	298	298	198
DG - Muni	42	0	0	50
Non-Crez	134	418	284	88
Distributed Solar - PG&E	163	190	702	2,306
Total	**1,051**	**1,411**	**1,823**	**3,147**

Table 4.2-3: New Renewable generation output in North PG&E areas

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Commercial Interest	1,637	932	563
Cost Constrained	3,787	2,511	3,186
Environmentally Constrained	1,543	540	754
High DG	1,423	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, so, the following sections include only the study results and mitigations.

4.2.1.1 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 61 MW of renewable generation in the Humboldt area in the Commercial Interest case, including this wind project, as well as the existing 11 MW Blue Lake biomass project. The Environmentally Constrained portfolio had 11 MW of renewable generation in the Humboldt area. The Cost Constrained portfolio had 81 MW of renewable generation and the High DG scenario had 53 MW of renewables including 42 MW of distributed generation and 11 MW from the existing Blue Lake biomass plant.

4.2.1.1.1 Study Results and Discussion

Thermal Overloads

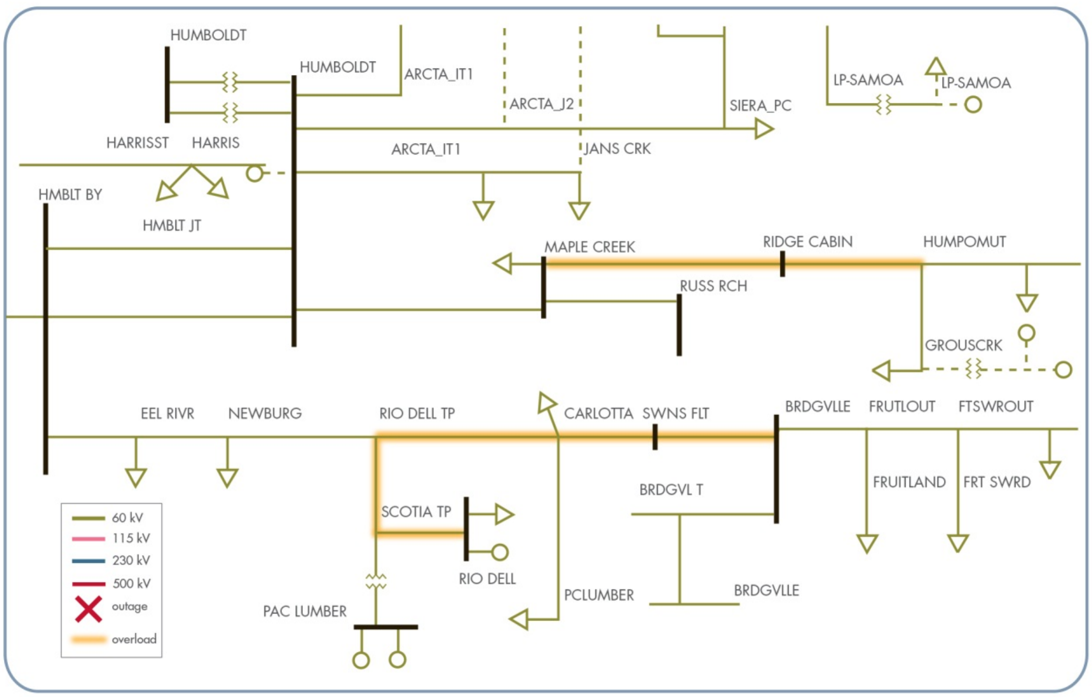
Trinity-Cottonwood 60 kV transmission line

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 Cost Constrained and Environmental portfolios under off-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 would eliminate the overload.

Rio Dell Junction-Bridgeville 60 kV transmission line

Multiple sections of the Rio Dell Junction-Bridgeville 60 kV transmission line may overload under Category B contingency conditions in the Commercial Interest portfolio. Overloads have been seen on the Rio Dell – Carlotta, Carlotta – Swans Flat and Swans Flat – Bridgeville sections of the line. These overloads were also observed in the reliability studies described in chapter 2. They are caused by a new renewable generation project modeled in the studies. The studies assumed that this project would reconductor the Rio Dell Tap 60 kV line to which it plans to connect. To mitigate the overloads with contingencies, the ISO proposed to install an SPS that would trip the new renewable project in case of overload if this project materializes. The observed thermal overload problems and their solutions are illustrated in Figure 4.2:2.

Figure 4.2:2: 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.

4.2.1.2 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 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 the project connected to the Geysers # 3-Cloverdale 115 kV line was modeled in all the portfolios but the project connected to the Lakeville # 2 line was not modeled. In addition, one other The renewable project was modeled in the North Coast area along the coast in the Cost Constrained portfolio and several new projects were modeled along the Coast, in North Bay and in the Sonoma County in the Environmentally Constrained portfolio. The High DG portfolio had multiple small renewable projects modeled around the area.

4.2.1.2.1 Study Results and Discussion

The scope of this analysis was limited to reporting the transmission issues resulting exclusively because of the renewable portfolio. Results of the North Coast and North Bay reliability analysis have already been presented in chapter 2. The study results of this powerflow and stability analysis provide details 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 contingencies. The analysis of the renewable portfolios found that all the constraints that were identified with the renewable portfolios modeled were also identified in the reliability assessment. Additionally it was also determined that the mitigations that were identified in the reliability assessment would also solve the thermal and voltage constraints that were seen in the analysis with renewable portfolios modeled.

Thermal Overloads

As mentioned above, the power flow analysis with the renewable portfolios modeled showed that all the thermal constraints identified were also seen in the reliability analysis discussed in chapter 2. The mitigations that were identified to resolve the issues were also seen to be effective for the cases in which renewable portfolios were modeled. No other thermal issues incremental to what have already been identified in the reliability assessment were seen in this analysis.

Voltage Issues

Voltage and Voltage Deviation Concerns

No voltage or voltage deviation issues in addition to what have already been identified in the reliability analysis discussed in chapter 2 were identified in this analysis. Voltage violation issues that are local in nature may arise depending on where the renewable generators will actually connect to the grid. Such issues can be sufficiently mitigated by requiring all renewable 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.

4.2.1.3 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. In addition to the Hatchet Ridge plant, the renewable portfolio studies included 7 MW of new renewable resources in the base and cost-constrained portfolios. In the environmentally-constrained portfolio, 106 MW of new renewable resources were modeled in North Valley area and 295 MW of renewable resources were modeled in the high DG portfolio.

4.2.1.3.1 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

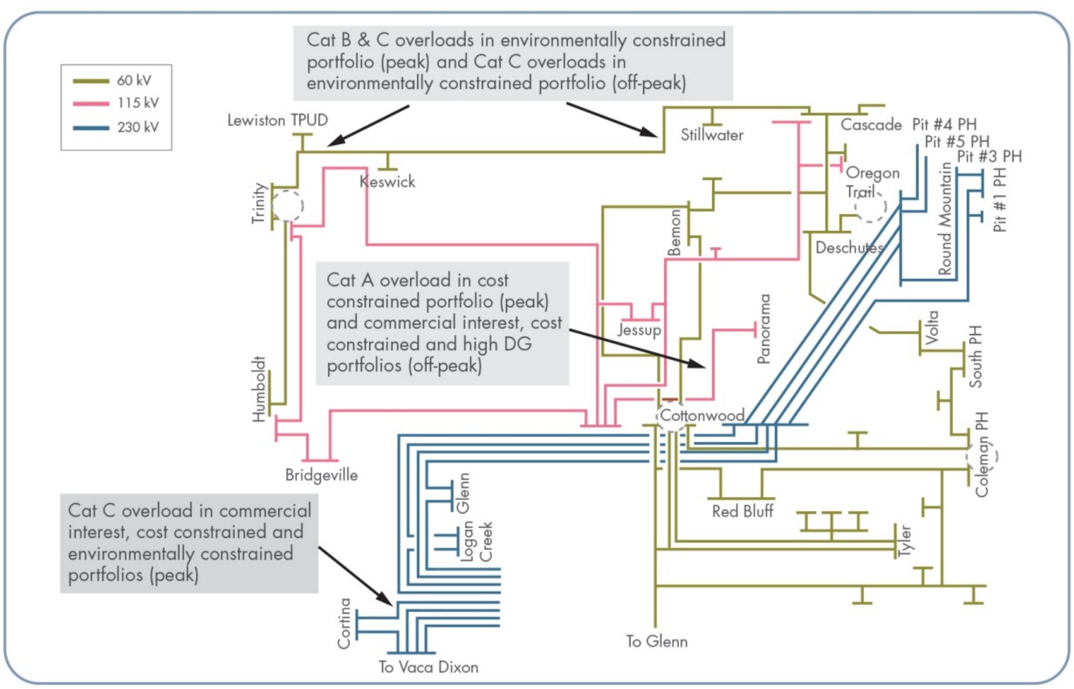
Cottonwood-Panorama 115 kV Line

The Cottonwood-Panorama 115 kV line is expected to overload under normal condition in the Commercial Interest and Cost Constrained portfolios in summer peak and in all four portfolios under off-peak conditions. The overload on this line is due to the over dispatch of the existing Simpson Power unit and can be mitigated by congestion management.

Trinity-Keswick & Keswick-Cascade 60 kV Line

The Trinity-Keswick & Keswick-Cascade 60 kV lines are expected to overload under categories B & C contingency conditions in the Environmentally Constrained portfolio in summer peak and under Category C conditions in off-peak. This is a localized issue caused by specific resource and will be addressed in the generator interconnection process.

Figure 4.2:3: Overload concerns in the North Valley area



Voltage Issues

No additional voltage issues were identified on top of what has been identified in the reliability assessment.

4.2.1.4 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, 814 MW of renewable resources were modeled in the Central Valley area (including 505 MW in Solano CREZ). In the Cost Constrained portfolio, 858 MW of new renewable resources were modeled in the Central Valley area (including 505 MW in Solano CREZ). In the Environmentally Constrained portfolio, 947 MW of new renewable resources were modeled in Central Valley area (including 505 MW in Solano CREZ). In the High DG portfolio, 1568 MW of new renewable resources were modeled in the Central Valley area (including 505 MW in Solano CREZ).

4.2.1.4.1 Study Results and Discussion

The following summarizes 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 contingencies. 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 in the Sierra and Stockton areas in the Commercial Interest, Cost Constrained and the Environmentally Constrained portfolios.

Stockton 'A' #1 and Stockton 'A'-Weber #3 60 kV Lines

The Stockton 'A' #1 and Stockton 'A'-Weber #3 60 kV lines are expected to overload under normal condition in the Commercial Interest and Cost Constrained portfolios in summer peak conditions. The Stockton 'A' #1 60 kV line is also overloaded under normal condition in the Commercial Interest, Cost Constrained and High DG portfolios in off-peak conditions. This is a localized issue caused by specific resource and will be addressed in the generation interconnection process generator interconnection process.

Tesla-Salado-Manteca and Tesla-Salado #1 115 kV

The Tesla-Salado-Manteca 115 kV line is expected to overload under normal condition in the Cost Constrained portfolio in summer peak conditions. The Tesla-Salado-Manteca and Tesla-Salado #1 115 kV lines are also overloaded under normal condition in the Cost Constrained portfolio in off-peak conditions. This is a localized issue caused by specific resource and will be addressed in the generation interconnection process generator interconnection process.

Drum-Rio Oso #1 & #2 and Drum-Higgins 115 kV lines

The Drum-Higgins 115 kV line is expected to overload under Category C contingency condition in Cost Constrained portfolio in summer peak conditions. Drum-Rio Oso #1 & #2 and Drum-Higgins 115 kV lines are also overloaded under categories B & C contingency conditions in all four portfolios in off-peak conditions. These overloads are due to high dispatch of Drum area hydro generation. Either the existing ISO operating procedure or congestion management will mitigate these overloads.

Table Mountain - Pease 60 kV Line

The overload on the Table Mountain - Pease 60 kV line is exacerbated under Category B contingency condition in High DG portfolio in off-peak conditions. The newly approved Second Pease 115/60 kV transformer project will mitigate this overload.

Tesla - Schulte 115 kV Line No. 2

The Tesla - Schulte 115 kV Line #2 line is expected to overload under Category C contingency condition in Commercial Interest, Cost Constrained and High DG portfolios in summer peak conditions. The overload is due to backing down of existing local resources and can be mitigated by pre-dispatching the GWF Tracy units.

Bellota-Riverbank-Melones 115 kV Line

The Bellota-Riverbank-Melones 115 kV line is expected to overload under Category C contingency condition in High DG portfolio in off-peak conditions. The overload can be mitigated by adding a sectionalizing breaker at Tesla 115 kV bus.

Figure 4.2:4: Overload concerns in the Northern Sierra area

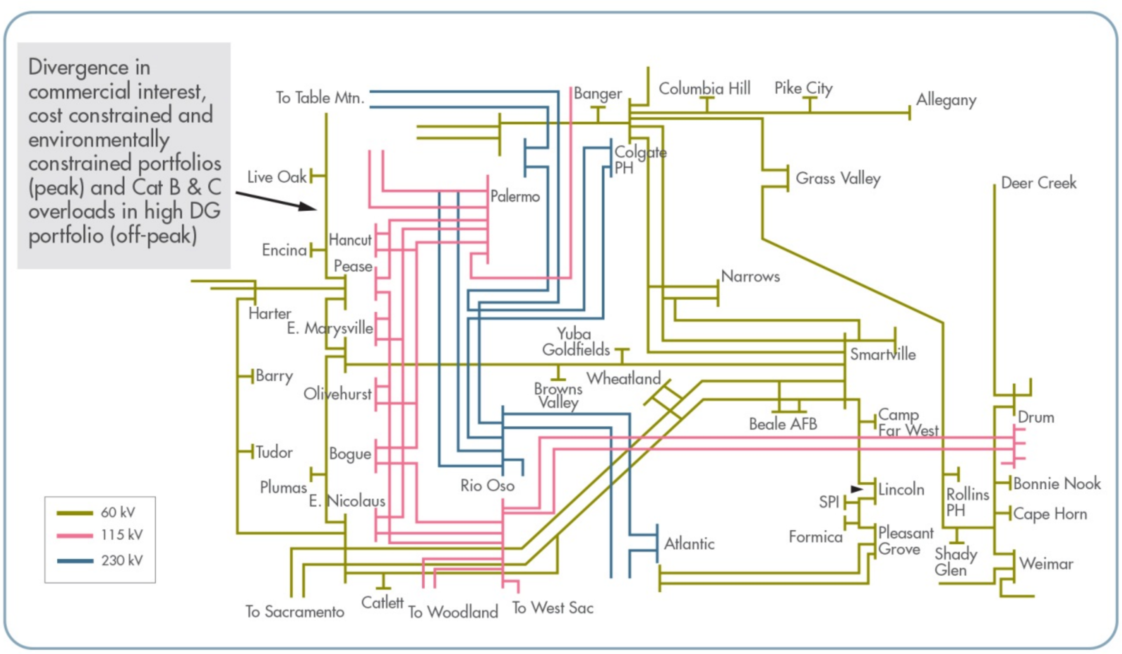


Figure 4.2:5: Overload concerns in the Southern Sierra area

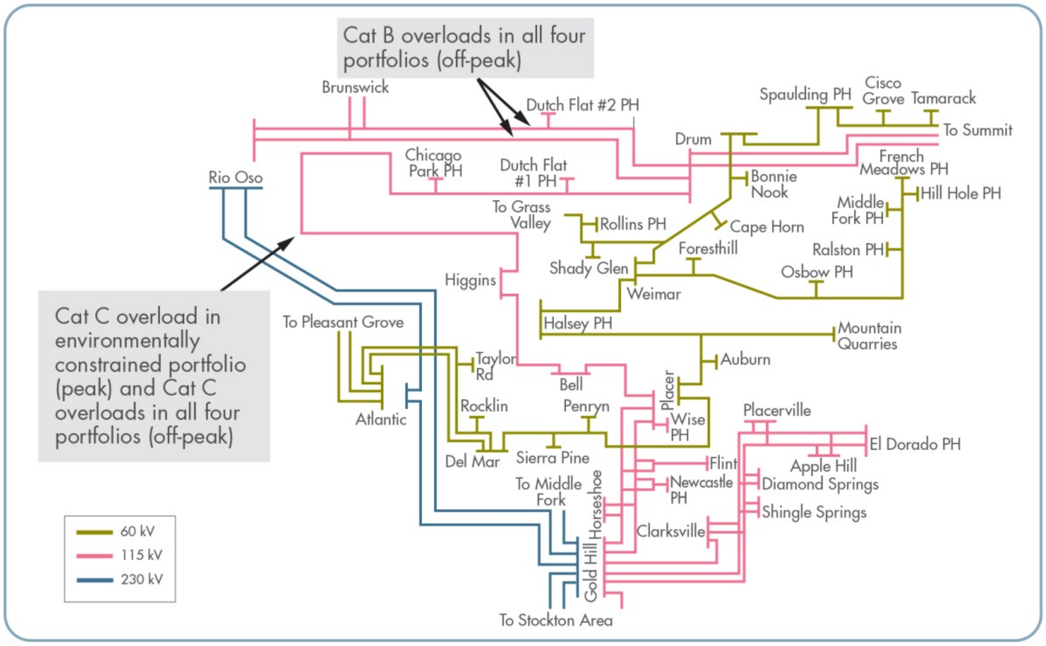
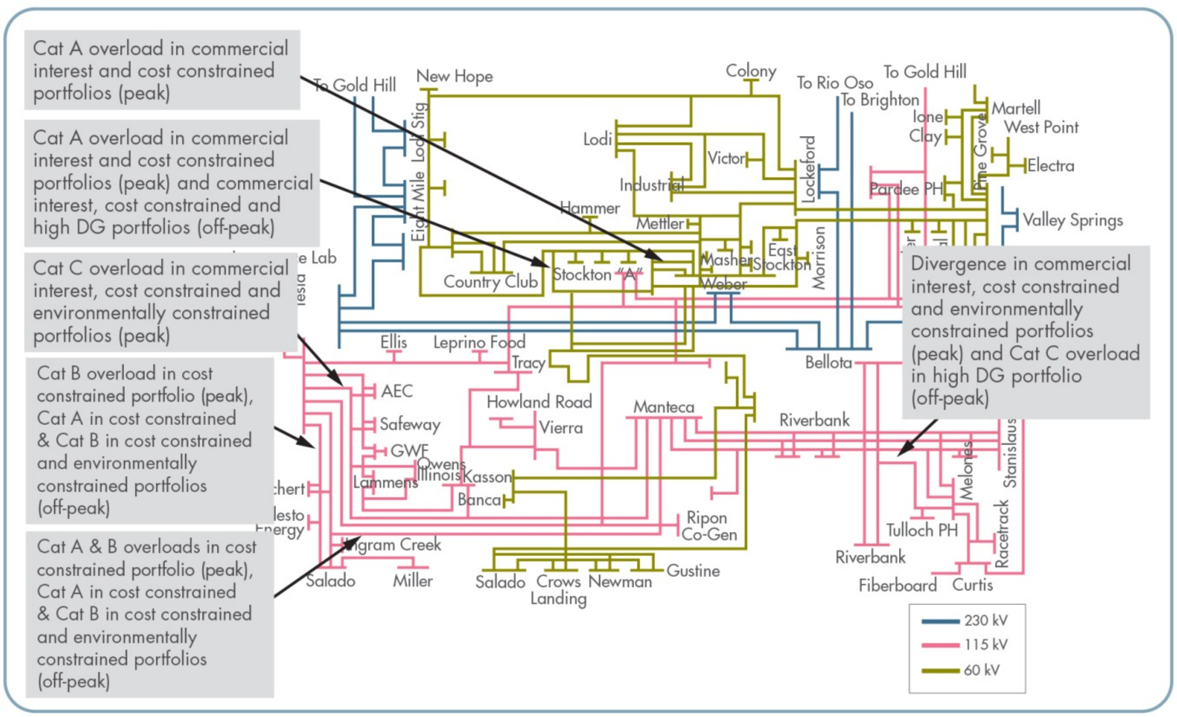


Figure 4.2:6: Overload concerns in the Stockton area



Voltage Issues

Voltage and Voltage Deviation Concerns

The study determined high voltage deviation at Bogue 115 kV bus under Category B contingency condition in Environmentally Constrained portfolio in summer peak conditions. The high voltage deviation is due to backing down of existing local resources and can be mitigated by pre-dispatching the FREC units. The study also determined high voltage deviation at Placerville area 115 kV buses under Category B contingency condition in Commercial Interest and Cost Constrained portfolios in summer peak conditions. The high voltage deviation is due to backing down of existing local resources and can be mitigated by pre-dispatching the Eldorado PH units.

The study also determined high voltages at Drum and Stockton 115/60 kV areas and Stanislaus 115 kV area under normal condition in all four portfolios during off-peak conditions. The Drum area high voltage is due to over dispatch of the Drum area hydro generation and can be mitigated by reducing the Drum area hydro dispatch. The Stockton and Stanislaus area high voltages can be mitigated by having 0.95 power factor reactive capability for the DG in the area.

The study also determined case divergence potentially due to voltage collapse under two Category C contingencies. These potential voltage collapses are due to backing down of existing local resources and can be mitigated by pre-dispatching the YCEC and GWF units.

4.2.1.5 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. Renewable portfolio studies included additional renewable generation capacity in the Bay area.

The High DG Portfolio had 297 MW of new renewable generation in the Alameda County, 70 MW in the San Mateo County, 198 MW of new renewable generation in the Santa Clara County, 249 MW of new renewable generation in the Contra Costa County, and 11 MW of new renewable generation in San Francisco-Peninsula.

The Environmental Constraint Portfolio had 222 MW of new renewable generation in the Alameda County, 71 MW in the San Mateo County, 191 MW of new renewable generation in the Santa Clara County, 206 MW of new renewable generation in the Contra Costa County, and 11 MW of new renewable generation in San Francisco-Peninsula.

The Commercial Interest portfolio had 6.6 MW of new renewable generation in the Alameda County, 1 MW in the San Mateo County, 138 MW of new renewable generation in the Santa Clara County, 120 MW of new renewable generation in the Contra Costa County, and no new renewable generation in San Francisco-Peninsula.

The Cost Constrained portfolio had 6.6 MW of new renewable generation in the Alameda County, 1 MW in the San Mateo County, 155 MW of new renewable generation in the Santa Clara County, 120 MW of new renewable generation in the Contra Costa County, and no new renewable generation in San Francisco-Peninsula.

The majority of the renewable projects modeled in the Bay area were small distributed photovoltaic generators.

Table 4.2-4: Summary of renewable generation capacity in PGE Greater Bay Area

Area by County	Renewable Generation Capacity by portfolio (MW)			
	Cost Constrained	Commercial Interest	Environmentally Constrained	High DG
Alameda	6.6	6.6	222	297
Contra Costa	120	120	206	249
Santa Clara	155	138	191	198
San Francisco	0	0	11	11
San Mateo	1	1	71	70
Total	**282.6**	**265.6**	**701**	**825**

Table 4.2-5: Summary of renewable generation dispatch in PGE Greater Bay Area

Portfolio	Renewable Capacity, MW	Output on peak, MW	Output off-peak, MW
Cost Constrained	282.6	38.2	55.7
Commercial Interest	265.6	34.2	51.4
Environmental	701	279.7	252.4
High DG	825	N/A	529.3

4.2.1.5.1 Study Results and Discussion

The following summarizes 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 contingencies. 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 and two transformer banks in the San Jose area were identified as overloaded.

Metcalf - Morgan Hill 115 kV transmission line

Metcalf - Morgan Hill 115 kV transmission line may overload with Category B and C contingencies in the Commercial Interest and Environmentally Constrained portfolios. The most critical single contingency is an outage of the Metcalf-Llagas 115 kV transmission line. The most critical Category C contingency is an outage at BUS FAULT AT 35642 MTCALF 2D 115.00. A mitigation solution to this overload is to pre-dispatch the Gilroy Generation in case of the overload. Another alternative would be the upgrade of the Metcalf - Morgan Hill 115 kV transmission line.

Llagas – Morgan Hill 115 kV transmission line

Llagas – Morgan Hill 115 kV transmission line is expected to overload under Category B and C contingency conditions. Category B and C overloads are expected in the in the Commercial Interest and Environmentally Constrained portfolios. The most critical single contingency is an outage of the Metcalf-Morgan Hill 115 kV transmission line. These overloads are explained by lack of local generation in the Gilroy area. Pre-dispatching the local Gilroy Generation would mitigate the overloads. Another alternative is to upgrade the Llagas – Morgan Hill 115 kV transmission line.

Metcalf 230/115 kV Bank 1

Metcalf 230/115 kV Bank 1may overload with an outage of the CB FAULT AT METCALF SUB 115 circuit breaker 492 (Category C). This overload is expected in all renewable portfolios. Possible mitigation solutions are to pre-dispatch LECEF for or re-sizing the bank or to trip some load at the San Jose Area with this contingency.

Metcalf 230/115 kV Bank 4

Metcalf 230/115 kV Bank 1may overload with an outage of the CB FAULT AT METCALF SUB 115 circuit breaker 502 (Category C). This overload is expected in all renewable portfolios. Possible mitigation solutions are to pre-dispatch LECEF for or re sizing the bank or to trip some load at the San Jose Area with this contingency.

Under peak load conditions, six transmission lines in the East Bay area were identified as overloaded.

Moraga - Station X 115 kV Transmission Line 1

Moraga – Station X 115 kV Transmission Line #1 may overload with Category C contingencies in all portfolios. The most critical single contingency is an outage of the CB FAULT AT 32780 CLARMNT 115 circuit breaker 122. A mitigation solution to this overload is to pre-dispatch the Oakland Generation in case of the overload. Another alternative would be the upgrade of the Moraga – Station X 115 kV Transmission Line #1.

Moraga - Station X 115 kV Transmission Line 2

Moraga – Station X 115 kV Transmission Line #2 may overload with Category C contingencies in all portfolios. The most critical single contingency is an outage of the CB FAULT AT 32780 CLARMNT 115 circuit breaker 122. A mitigation solution to this overload is to pre-dispatch the Oakland Generation in case of the overload. Another alternative would be the upgrade of the Moraga – Station X 115 kV Transmission Line #2.

Moraga - Station X 115 kV Transmission Line 3

Moraga – Station X 115 kV Transmission Line #1 may overload with Category C contingencies in all portfolios. The most critical single contingency is an outage of the CB FAULT AT 32780 CLARMNT 115 circuit breaker 122. A mitigation solution to this overload is to pre-dispatch the Oakland Generation in case of the overload. Another alternative would be the upgrade of the Moraga – Station X 115 kV Transmission Line #3.

Moraga - Claremont 115 kV Transmission Line 1

Moraga - Claremont 115 kV Transmission Line 1 may overload with Category C contingencies in all portfolios. The most critical single contingency is an outage of the CB FAULT AT 32790 STATIN X 115 circuit breaker 372. A mitigation solution to this overload is to pre-dispatch the Oakland Generation in case of the overload. Another alternative would be the upgrade of the Moraga - Claremont 115 kV Transmission Line 1.

Moraga - Claremont 115 kV Transmission Line 2

Moraga - Claremont 115 kV Transmission Line 2 may overload with Category C contingencies in all portfolios. The most critical single contingency is an outage of the CB FAULT AT 32790 STATIN X 115 circuit breaker 372. A mitigation solution to this overload is to pre-dispatch the Oakland Generation in case of the overload. Another alternative would be the upgrade of the Moraga - Claremont 115 kV Transmission Line 2.

Under non-peak load conditions, one transmission lines in the San Jose area was identified as overloaded.

Trimble - San Jose B 115 kV Line Transmission Line 1

Trimble - San Jose B 115 kV Line Transmission Line #1 may overload with Category C contingencies in all portfolios. The most critical single contingency is a double line outage of the Los Esteros - Trimble 115 kV Transmission Line and Los Esteros - Montague 115 kV Transmission Line. A mitigation solution is the upgrade of the Trimble - San Jose B 115 kV Line Transmission Line #1.

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 4.2:7 shows the simplified Bay Area diagram and the identified overloads.

Figure 4.2:7: Greater Bay area thermal overload concerns

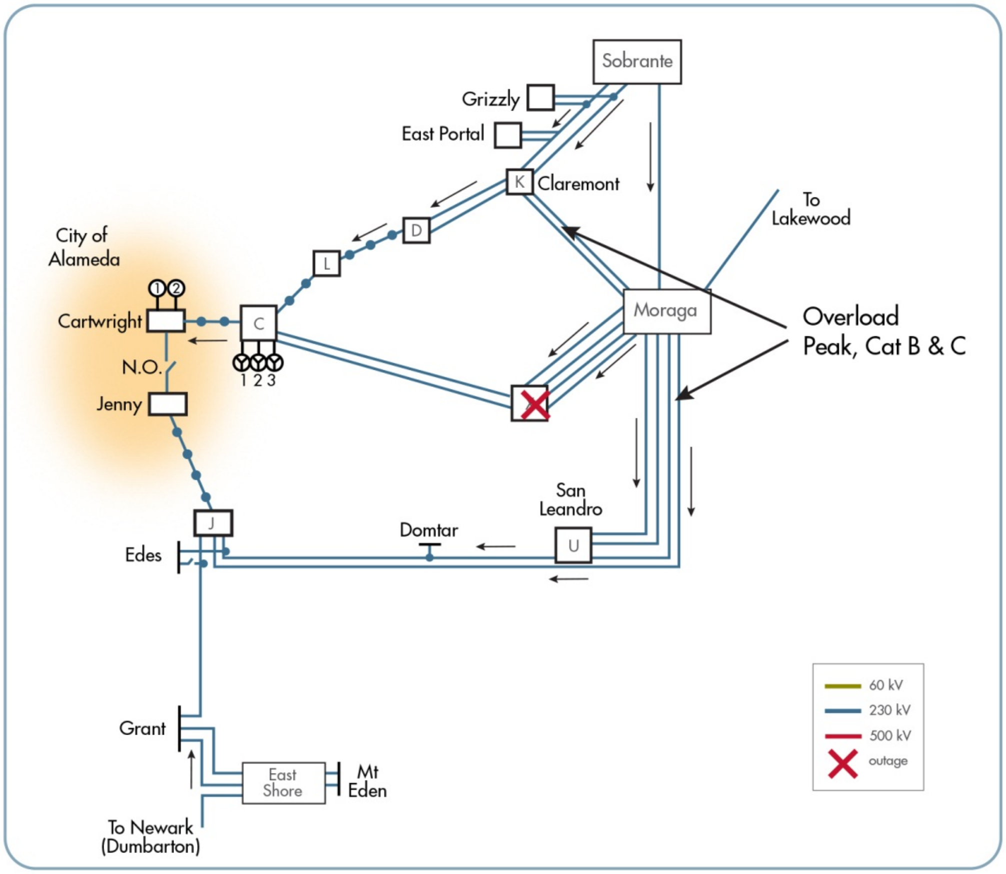
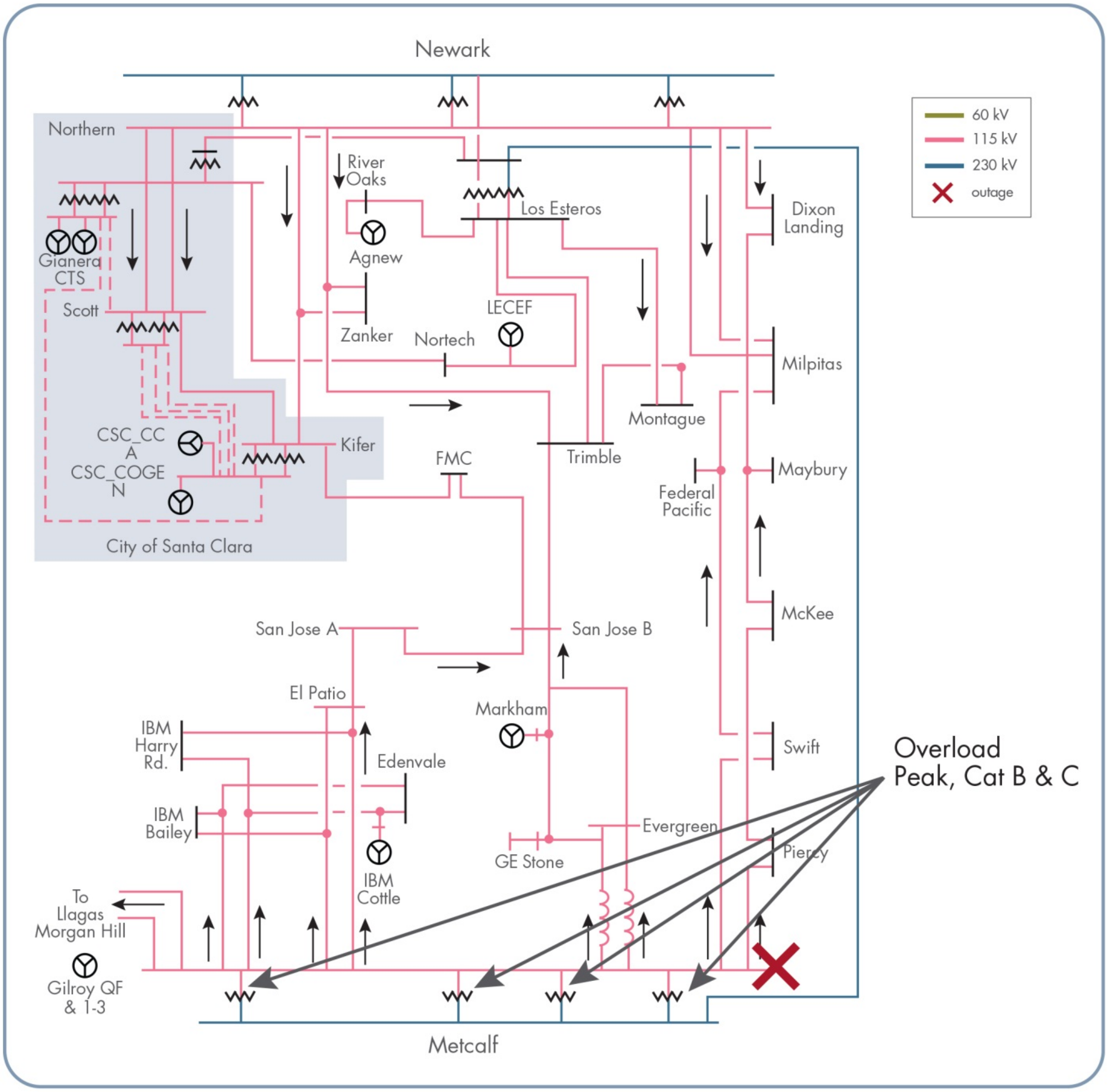


Figure 4.2:8: Greater Bay area overload concerns



Voltage Issues

Voltage and Voltage Deviation Concerns

Under peak load conditions, low voltages and voltage deviation were observed in the San Jose Morgan Hill & Llagas Area 115 kV system in all portfolios.

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 San Jose areas. Another alternative is to pre-dispatch Gilroy Generation for voltage support.

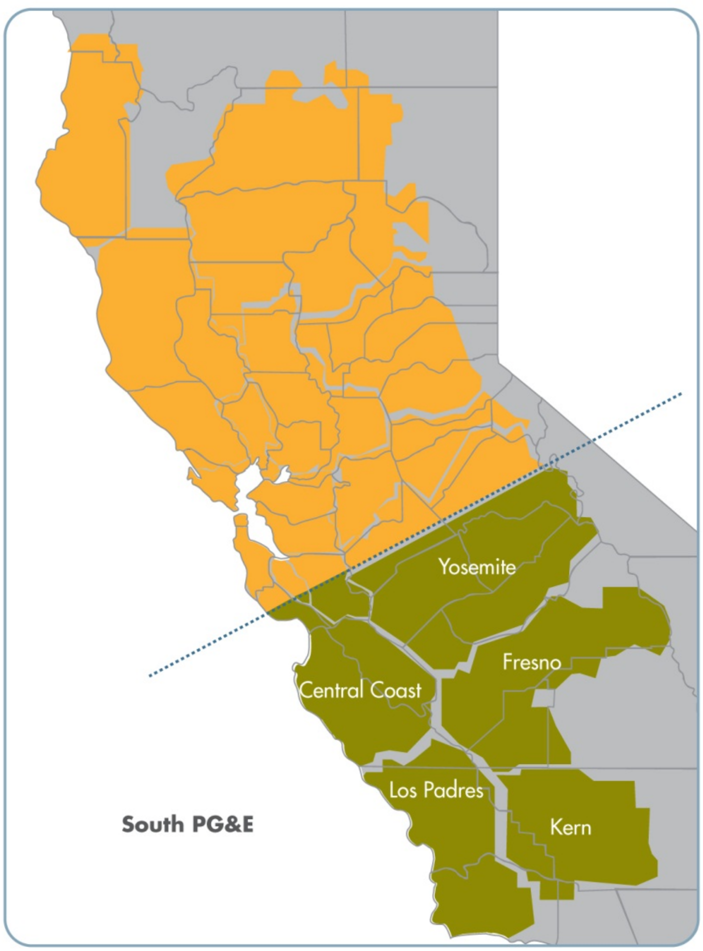
Under off-peak load conditions, low voltages and voltage deviation were observed in the Mission Area 115 kV system in all portfolios.

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 San Jose areas. Another alternative is to pre-dispatch Russell City Generation for voltage support.

4.2.2 Southern PG&E Policy-Driven Powerflow and Stability Assessment Results and Mitigations

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. The South PG&E division is shown in the figure below. The details of all the individual areas have already been captured in chapter 2.

Figure 4.2:9: Southern PGE system



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 in the tables below, respectively.

Table 4.2-6: Summary of renewable generation in South PG&E area

Area	**Renewable Generation by portfolio (MW)**			
	Cost Constrained	**Commercial Interest**	**Environmentally constrained**	**High DG**
PG&E South (CREZ)*	2,400	2,400	2,400	1,890
PG&E South (Non-CREZ)	3	3	3	3
PG&E South (DG)	870	1270	1560	1300
Total	**3,273**	**3,673**	**3,962**	**3,193**

* Carrizo South & Westland CREZ

Table 4.2-7: Summary of renewable generation dispatch in PGE south

Portfolio	**Renewable Capacity, MW**	**Output on peak, MW**	**Output off-peak, MW**
Cost Constrained	3,273	2,259	1,734
Commercial Interest	3,673	2,551	1,852
Environmental	3,962	2,689	1,928
High DG	3,193	N/A	2,564

4.2.2.1 Fresno and Kern Area

4.2.2.1.1 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

Wilson-Le Grand 115 kV and Dairyland-Le Grand 115 kV lines

These line sections were found to be overloaded under Category C1 contingencies in the Cost, Commercial and Environmentally Constrained portfolios under peak conditions. Wilson-Le Grand was also constrained under a C1 contingency during off-peak conditions. Reconductoring of the 115 kV path would alleviate this constraint.

Schindler-Huron-Gates 70 kV line

This section of the line was found to be overloaded under Category C2 contingencies in the Cost, Commercial and Environmentally Constrained portfolios peak conditions. Sectionalizing the Panoche 115 kV bus would correct this problem, as well as several other overloads caused by this contingency. This is a local concern that should be addressed during the generator interconnection process.

Borden-Gregg #1 230 kV line

This section of the line was found to be overloaded under Category C2 contingencies in the Cost and Commercial Constrained portfolios peak conditions. Sectionalizing the bus at Herndon 230 kV and Herndon 115 kV solves this overload condition. PG&E has submitted a project that includes sectionalizing the Herndon 230 kV bus.

Schindler-Coalinga #2 70 kV and Schindler-Huron-Gates 70 kV lines

These lines were found to be overloaded under Category C5 contingencies in the Cost, Commercial and Environmentally Constrained portfolios under peak and off-peak conditions. There are no generation solutions that could be used to mitigate either of these overloads for this C5 contingency, so an SPS to reduce renewables in this area is recommended. This is a local concern that should be addressed during the generator interconnection process.

Manchester-Airways-Sanger 115 kV line

This overload was observed in off-peak Cost, Commercial, & Environmental Constrained portfolios for two C5 contingencies as well as a C2 contingency in the peak Environmental case. Reconductoring of the 115 kV path from Herndon to Sanger would correct this overload. The North Fresno 115 kV Reinforcement Project may mitigate this and further study will be necessary.

Kearney-Herndon 230 kV line

This overload was observed in the Commercial off-peak case. The worst overload was observed for the Category C5 contingency, Gates-Gregg and Gates-McCall 230 kV lines. Some potential mitigation projects are to reconductor the transmission line or modify the HTT/RAS to trip another pump for this C5 contingency. 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.

Voltage Issues

Off-Peak Voltage and Voltage Deviation Concerns

There were no low voltage problems in the Fresno area. Four off-peak high voltage issues were seen in Fresno in all portfolios. Three of these were observed under normal conditions. One high voltage problem at Borden 70 kV was found after a C5 contingency. In the Kern area, there were no high voltages, but there was one Category A low voltage problem at the Chevron Lost Hills 70 kV bus in all off-peak cases. There were no off-peak voltage deviation problems in Fresno or Kern areas.

Borden 70 kV bus

This deviation was observed in the all off-peak cases for a C5 contingency. To mitigate this voltage deviation, an SPS to decrease renewable generation in the area would need to be developed.

On-Peak Voltage and Voltage Deviation Concerns

In the Fresno area, seven Category C contingency low voltage violations were observed in all portfolios under peak conditions. These problems were in the Merced 70 kV area for C1 contingencies of Exchequer 115 kV bus or Le Grand 115 kV bus. Two of these problems were seen in both the peak and off-peak cases at the Merced 70 kV and Oakhurst 115 kV areas.

Mariposa 70 kV bus

This voltage problem was observed in the Cost and Environmental Constrained portfolios peak cases for a C1 contingency. To mitigate this low voltage, reactive support at Mariposa might have to be added in the generator interconnection process for the renewables in this area.

There were two voltage deviations for Category C1 contingencies in the Fresno area and none seen in the Kern area.

Bonita 70 kV bus

This deviation was observed in the all peak cases for a C1 contingency. The Environmentally Constrained case was the worst. To mitigate this voltage deviation, reactive support on the Merced 70 kV system might need to be added in the generator interconnection process for the renewables in this area.

Oakhurst 115 kV bus

This deviation was observed in the all peak cases for a C1 contingency. The Cost Constrained case was the worst. To mitigate this voltage deviation, reactive support at the Oakhurst 115 kV bus might need to be added in the generator interconnection process for the renewables in this area.

4.2.2.2 Central Coast and Los Padres Area

4.2.2.2.1 Study Results and Discussion

Following 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 voltage performance requirements under normal and various system contingency conditions. The discussion includes proposed mitigation plans for these reliability concerns.

Thermal Overload

Morro Bay-Solar Switching Station 230 kV #1 and #2 lines

These facilities were observed to be loaded at 106 percent-107 percent under the off-peak conditions for all the renewable portfolio scenarios with the exception of the High DG Constraint, which was loaded at 99.9 percent following the loss of the Midway-Caliente Switching Station 230 kV #1 & 2 double circuit tower lines.

For the peak conditions, the Morro-Solar Switching Station 230 kV #1 Line was also found to be overloaded more than 10 percent (110.8 percent - 112.7 percent) following a circuit breaker outage (Category C2) at the Morro Bay 230 kV Substation (circuit breaker 622) for all the three studied scenarios (CI, CC and ENV).

For these identified thermal overloads, the recommendation is to develop an SPS to trip sufficient renewable generation, relocate the generation or reconductor the overloaded lines to mitigate the problem.

San Luis Obispo-Carrizo 115 kV #1 Line

This facility was identified as not meeting thermal loading performance requirements under Category 5 (double circuit tower lines) system contingency and peak conditions following loss of Morro Bay-Solar Switching Station 230 kV #1 & 2 Lines. The loading levels were between 119 percent and 121.4 percent.

The mitigation for this thermal overload is to install SPS to trip renewable generators, relocate the generation or reconductor the overloaded line.

Voltage Issues

The study identified the high side of the renewable generator step-up transformer as well as the associated point-of-Interconnection (TT2284 Sub) interconnecting to the Manville-Lompoc Jct 115 kV Line as not meeting the low voltage performance requirements under Category C (C5, C1 and C2) system contingency and peak conditions following loss of Morro Bay-Solar Switching Station 230 kV #1 & 2 Lines. The loading levels were 119 percent and 121.4 percent. Because of the significant low voltages, the recommendation is to install reactive support to be consistent with the CAISO 0.95 lead and 0.95 lag power factor requirements.

4.2.3 PG&E Bulk System Policy-Driven Powerflow and Stability Results and Mitigations

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. The studies also included extreme events such as a northeast and southeast separation, outage of all three lines of Path 26 and outages of major substations, such as Los Banos, Tesla and Midway (500 and 230 kV busses). Under the peak load conditions, three generation portfolios were studied: Commercial Interest, Cost Constrained and Environmentally Constrained. Under the off-peak load conditions, in addition to these three portfolios, the High DG portfolio was also studied. Studying this portfolio under peak load conditions was not necessary because it was not expected to be critical because of a large amount of distributed generation in this portfolio that relieved stress on the system during high loads. Under off-peak conditions, the concerns with this portfolio were high voltages and any other issues that may be caused by over generation.

For the peak load conditions, it was assumed that the Helms Pump Storage Power Plant operates in the generation mode with three units generating. 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 two units pumping in all portfolios.

Post transient and transient stability studies were conducted for all the cases and scenarios.

Transient stability studies for the peak load conditions did not identify any additional criteria violations or undamped oscillations compared with the reliability studies. On the contrary, transient voltage dip at Wind Gap with three-phase faults at the Midway 230 kV bus was not as large as in the reliability studies, and the oscillations were not as large also. Wind Gap pump load was not tripped by under-voltage or under-frequency relays with the Midway 230 kV Category C contingencies as it was observed in the reliability studies. The better system performance can be explained by the dynamic reactive support from the new generation projects located in the Midway area. However, the new projects were not sufficient to mitigate all the concerns. The contingencies involving three-phase faults at the Gates 230 kV bus also showed improved system performance compared with the reliability studies. None of the load connected to the Gates 115 kV bus was tripped for under-frequency and the frequency dip was not as large; however, the transient frequency concerns at the Gates 115 kV bus still remained in the 33 percent RPS studies for all portfolios and system conditions.

Compared with the reliability studies, the transient stability studies for the off-peak load conditions identified additional concerns regarding frequency dip with an outage of the Table Mountain 500/230 kV transformer.

For the post transient (governor power flow) studies, only transmission facilities 115 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.

4.2.3.1 Study Results and Discussion

Thermal Overloads

Round Mountain 500/230 kV transformer

Round Mountain 500/230 kV transformer was identified as overloaded under off-peak load conditions with Category B contingencies. The overload was identified in all portfolios except for the one with high distributed generation. The most critical contingency appeared to be an outage of the Olinda 500/230 kV transformer.

Mitigation solution for this overload is to modify the existing Colusa SPS to monitor also transformer outages and Round Mountain transformer overload. The SPS trips Colusa generation, which will mitigate the Round Mountain transformer overload.

The Round Mountain area and the contingencies that may cause Round Mountain transformer overload are shown in the figure below.

Figure 4.2:10: Northern California 500/230 kV transformer overloads

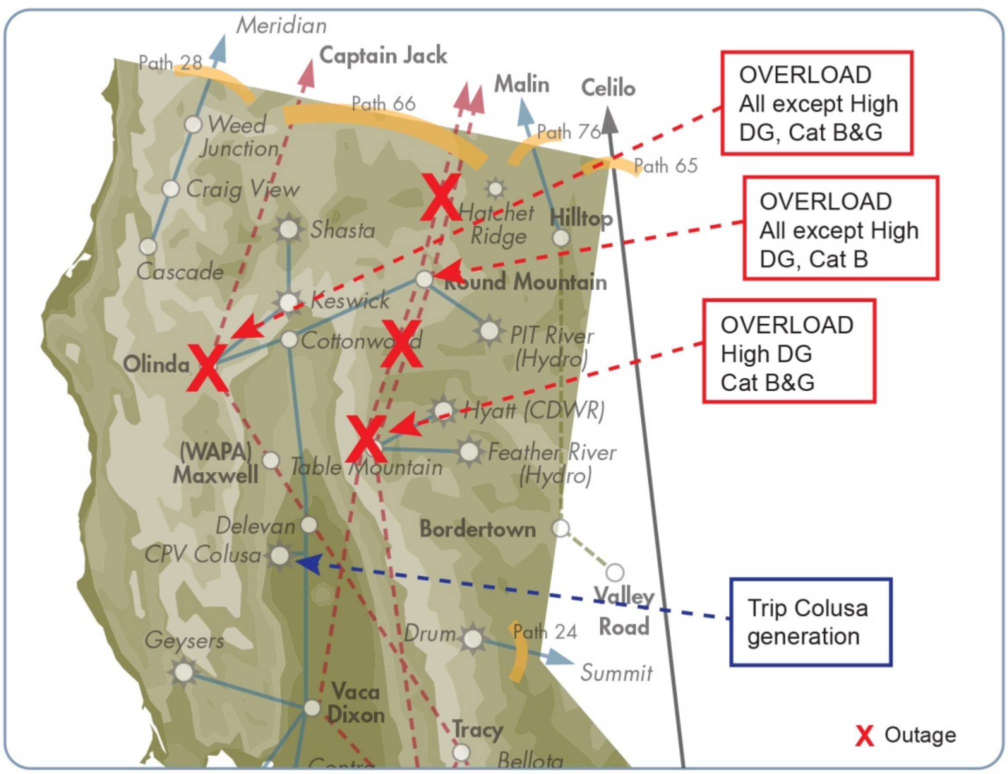


Table Mountain 500/230 kV transformer

This transformer was identified as loaded to 99 percent of its normal rating in the High DG portfolio off-peak case. Power flow through the transformer in this case was from the 230 kV bus to the 500 kV bus. High flow was caused by high renewable and hydro generation and relatively low load under off-peak load conditions. The Table Mountain transformer does not have an emergency rating. The Table Mountain 500/230 kV transformer was identified as overloaded in the same portfolio under the same load conditions for a Category B contingency of an outage of the Round Mountain 500/230 kV transformer and for Category C contingencies of a double outage of the Round Mountain-Table Mountain 500 kV transmission lines or a double outage of the Malin-Round Mountain 500 kV transmission lines.

Mitigation of the overload on the Table Mountain 500/230 kV transformer with contingencies can be tripping some of the generation units connected to its 230 kV bus, such as Hyatt or Thermalito. Another solution that will also reduce loading under normal conditions is congestion management that would limit flow through the Table Mountain transformer to 900 MW or lower. This will allow the avoidance of an overload under these contingency conditions.

The Table Mountain area and the contingencies that may cause Table Mountain transformer overload are shown in Figure 4.2:10.

Olinda 500/230 kV Transformer

The Olinda 500/230 kV transformer was identified as overloaded with a Category B contingency (an outage of the Round Mountain 500/230 kV transformer) in all portfolios except for the High DG. The Olinda transformer overload was also observed with a Category C contingency (double outage of the 500 kV Malin - Round Mountain transmission lines) in the Environmentally Constrained portfolio. All the overloads are expected under off-peak load conditions.

Mitigation solution is to modify the existing Colusa SPS to trip Colusa generation also for transformer outages. Tripping Colusa generation will mitigate the Olinda 500/230 kV transformer overload.

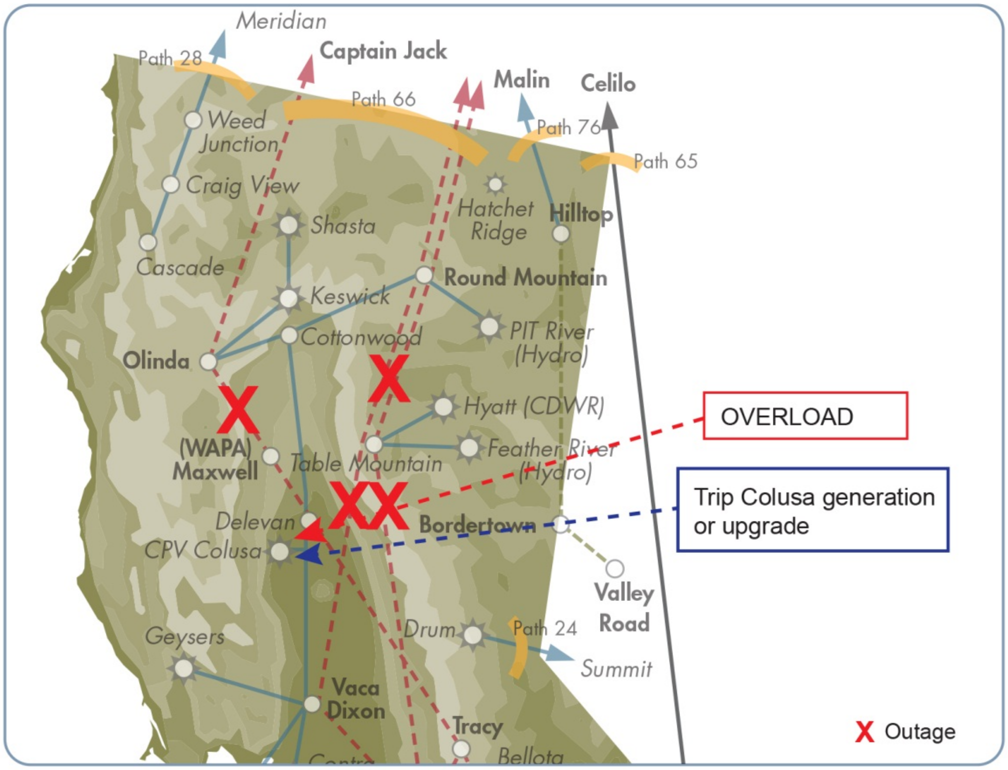
The Olinda area and the contingencies that may cause Olinda transformer overload are shown in Figure 4.2:10.

Delevan-Cortina 230 kV Transmission Line

This transmission line is expected to be loaded up to 99 percent of its emergency rating with an outage of the Olinda-Tracy 500 kV line (Category B) and to overload with several Category C contingencies with a double outage of both Round Mountain-Table Mountain 500 kV lines being the most critical. The overloads are expected under peak load conditions in the Commercial Interest and Cost Constrained portfolios.

The location of the Delevan-Cortina transmission line and the outages that cause its overload is illustrated in the figure below.

Figure 4.2:11: Delevan-Cortina 230 kV line overload



Potential mitigation for the overload is installing an SPS to trip generation from the Colusa power plant for Category B contingency and adding Colusa generation to existing SPS for Category C contingencies. Another solution is an upgrade of the Delevan-Cortina 230 kV transmission line. Congestion management that would reduce Colusa generation will also mitigate the overload.

Westley-Los Banos 230 kV Transmission Line

The Westley-Los Banos 230 kV line was also identified as overloaded in the reliability studies. However, the overload was identified in the reliability studies only for one Category C contingency under off-peak load conditions (500 kV double line outage north of Los Banos) and the overload was 15 percent over the line emergency rating. The policy-driven assessment cases have a generation project connected to the Westley-Los Banos line modeled in the Commercial Interest and Environmentally Constrained portfolios. The section of the Westley-Los Banos 230 kV line between Westley and the new project switching station was identified as slightly (1 - 2 percent) overloaded with Category C contingencies under peak load conditions in the Commercial Interest and Environmentally Constrained portfolios and severely (up to 35 percent) overloaded with Category C contingencies under off-peak load conditions in all portfolios except for the one with high distributed generation. Even if this section was not overloaded with Category B contingencies, its loading was observed to be as high as 99 percent of its emergency rating with the Tesla-Los Banos 500 kV line outage under off-peak load conditions in the Commercial Interest case. The section between the new project switching station and Los Banos was identified as overloaded under off-peak conditions for a Category C contingency, 500 kV double line outage north of Los Banos, in all portfolios except for the one with high distributed generation. The overload was as high as 28 percent in the Commercial Interest case. Figure 4.7.3-3 illustrates this overload.

Mitigation of the overload on the section between Westley and the new project switching station is planned within the large generator interconnection process. This line section will be upgraded as a delivery network upgrade for the new project interconnecting to the Westley-Los Banos line. Potential mitigation for overload on the section between the switching station and Los Banos can be upgrade of this section or modification of the RAS for the 500 kV double line outage north of Los Banos. Mitigation of the overload will require tripping of more generation south of Los Banos, including some generation in Southern California in case if tripping generation at Midway is not sufficient. Another solution can be installing a series reactor or a Flexible AC transmission system (FACTS) device on the overloaded section.

The ISO is working with PG&E on solutions to the Central California transmission system overloads that may include these or other mitigation alternatives.

Moss Landing – Panoche 230 kV Transmission Line

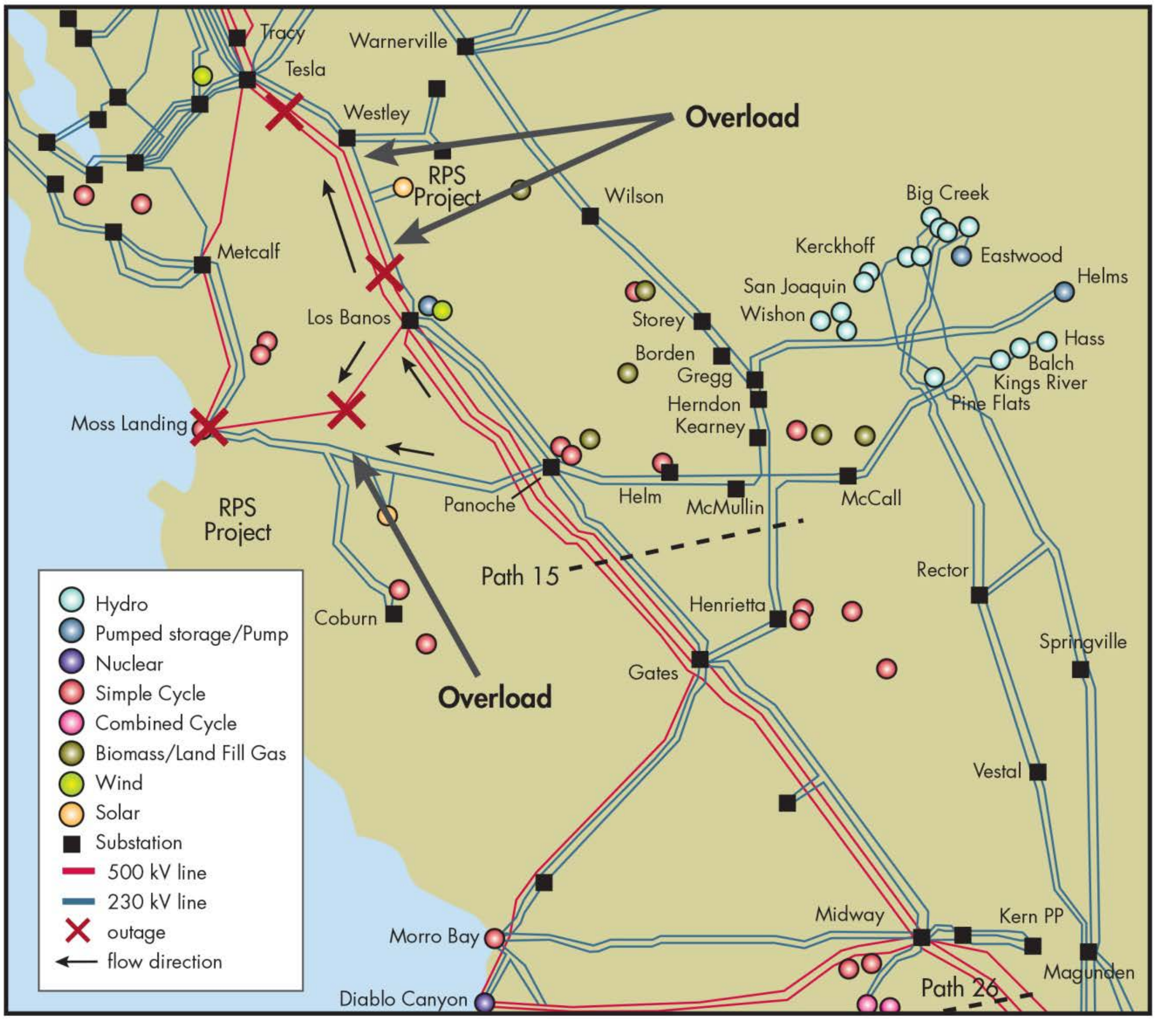
The policy-driven studies modeled a new generation project connected to the Moss Landing - Panoche and Coburn-Panoche 230 kV transmission lines. It was modeled in all portfolios except for the High Distributed Generation Portfolio.

The studies showed that the new project may cause overload on the section between Moss Landing and the Project's switching station for Category B contingencies (Moss Landing-Los Banos 500 kV outage and Moss Landing 500/230 kV transformer outage) under peak load conditions in the Environmentally Constrained portfolio and loading for up to 99 percent of this section emergency rating with the same contingencies under off peak conditions in the Commercial Interest portfolio.

Mitigation solution is to install an SPS that would trip generation from the new project in case of the Switching Station – Moss Landing section overload. Another alternative is to open the circuit breaker at the project's switching station that connects it with the Panoche substation if the overload occurs. This switching will mitigate the overload and at the same time avoid tripping generation.

The Central California area and the overloaded line are shown in the figure below.

Figure 4.2:12: Overloads in Central PG&E area



Kearney-Herndon 230 kV and Panoche-Gates # 1 and 2 230 kV Transmission Lines

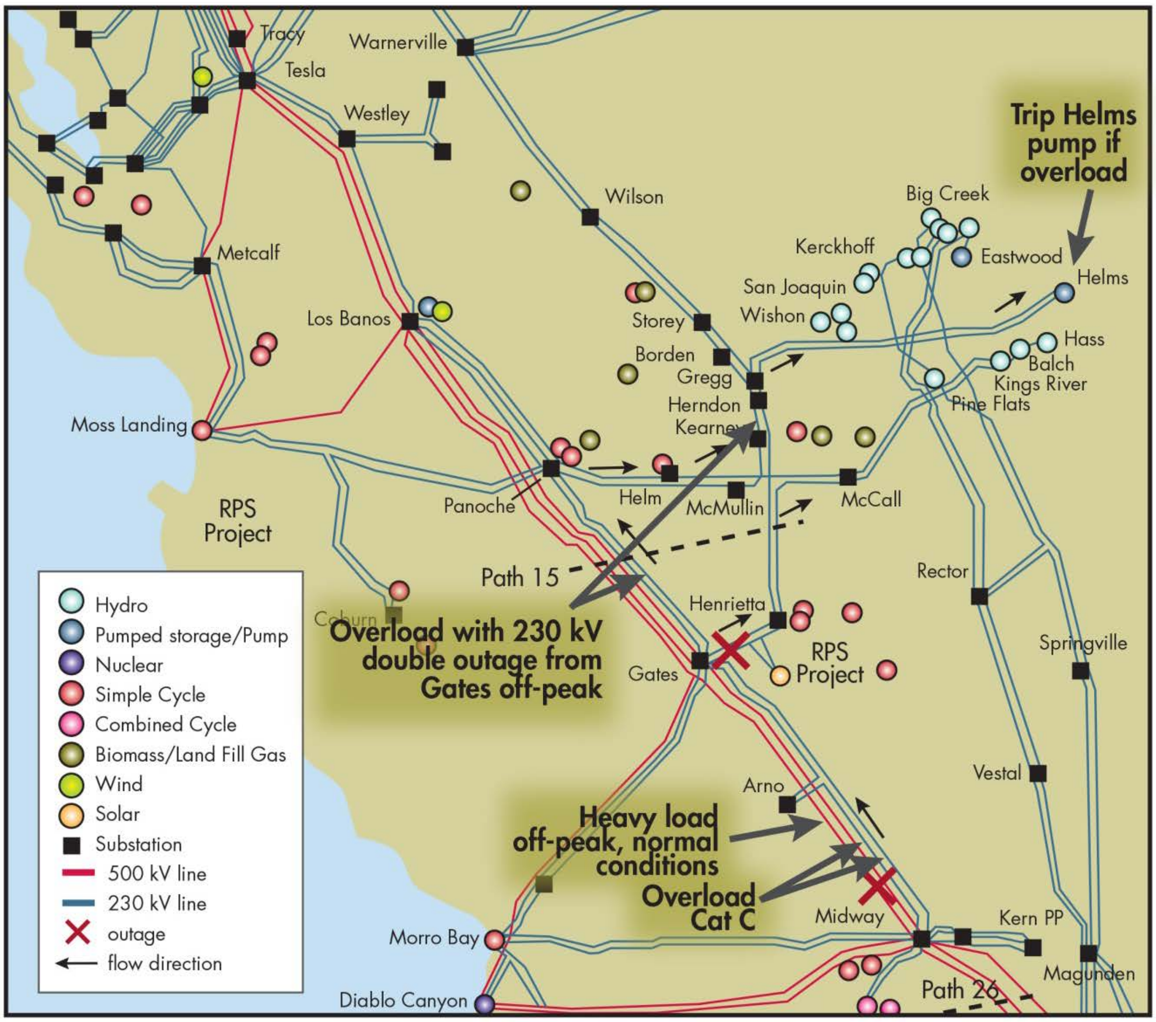
The policy-driven studies modeled a new generation plant connected to the Gates-Gregg and Gates-Mc Call 230 kV transmission lines between Gates and Henrietta. The project was modeled in all portfolios. It was assumed that both lines will be looped into this project's switching station. Having a switching station will change topology with a double outage of the Gates-Gregg and Gates-Mc Call 230 kV lines. Before the new project's interconnection, a fault on the Gates-Gregg and Gates-Mc Call 230 kV lines that are strung on the same towers from the Gates Substation to the Raisin Junction would take both lines out of service for their whole length because there are no circuit breakers on these lines except at the Gates, Gregg and Mc Call substations and the Henrietta substation has a tap connection to the lines. With the new switching station, only the sections between Gates and the switching station will be out if the fault occurs on this part of the lines. There is an existing SPS that trips Helms pumping load in case of the Gates-Gregg and Gates-Mc Call 230 kV double outage.

The studies showed that if this SPS is not applied, Kearney-Herndon 230 kV line may overload and both Panoche-Gates 230 kV circuits may load for up to 99 percent of their emergency ratings with a double outage of Gates-New Project Switching Station 230 kV lines. These overloads were identified under off-peak conditions in the Commercial Interest portfolio.

Mitigation solution is to trip one Helms pump (it was assumed that two pumps at Helms are on under off-peak conditions). A double outage of the 230 kV lines between the switching station and Gregg and the switching station and Mc Call will require tripping of two Helms pumps.

The system configuration in this area and the Gates-Gregg, Gates-McCall double outage are illustrated in the figure below.

Figure 4.2:13: Overloads in South PG&E



Gates-Midway and Arco-Midway 230 kV Transmission Lines

Overload on the Gates-Midway and Arco-Midway 230 kV transmission lines was identified with a 500 kV double outage north of Midway (Category C contingency). The overload was observed under off-peak conditions in all portfolios except for High Distributed Generation. In addition, the Midway-Gates 500 kV transmission line was loaded up to 99 percent of its normal rating under off-peak load conditions with all facilities in service in the Commercial Interest portfolio. The

Commercial Interest portfolio as the most critical for the overload on the Gates-Midway 230 kV and Arco-Midway 230 kV transmission lines.

These overloads are illustrated in Figure 4.2:13.

The Gates-Midway and Arco-Midway 230 kV lines have short-term (30-minutes) emergency rating. However, using this rating will not be sufficient for the Gates-Midway 230 kV line overload in the Commercial Interest and Environmentally Constrained portfolios. The existing RAS for the north of Midway 500 kV double outage will require modification to add tripping of more generation at Midway, including new renewable projects and tripping of all Helms pumps.

Voltage Issues

Voltage and Voltage Deviation Concerns

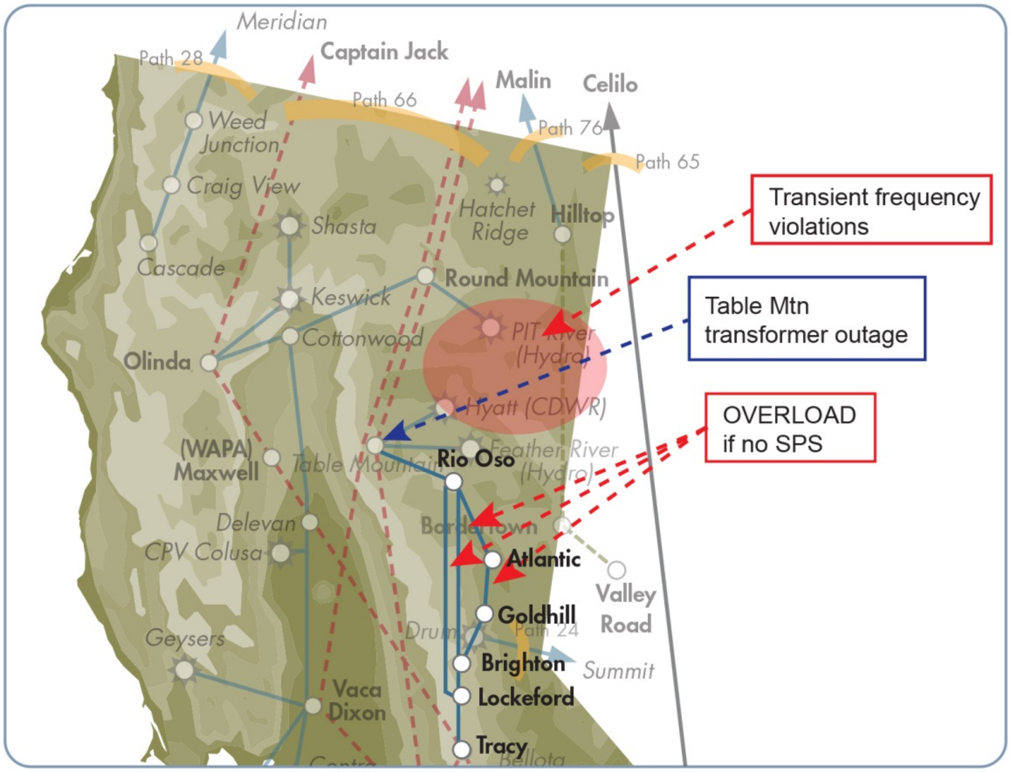
No voltage or voltage deviation concerns were identified on the PG&E bulk system in the studies in any renewable portfolios both under peak and off peak load conditions.

Transient Stability Concerns

Compared with the results of the reliability studies described in chapter 2, additional concerns were identified only with an outage of the Table Mountain 500/230 kV transformer under off-peak load conditions in all portfolios.

There is an existing SPS for the Table Mountain transformer outage that trips generation from the Hyatt and Thermalito hydro power plants. Tripping this generation is needed under off-peak load conditions to protect the underlying 230 kV and 115 kV transmission systems in the Table Mountain-Rio Oso area. The studies showed that if the SPS is not applied, the High Distributed Generation portfolio will be the most critical, but overloads are expected in all portfolios. Figure 4.2-14 illustrates these overloads.

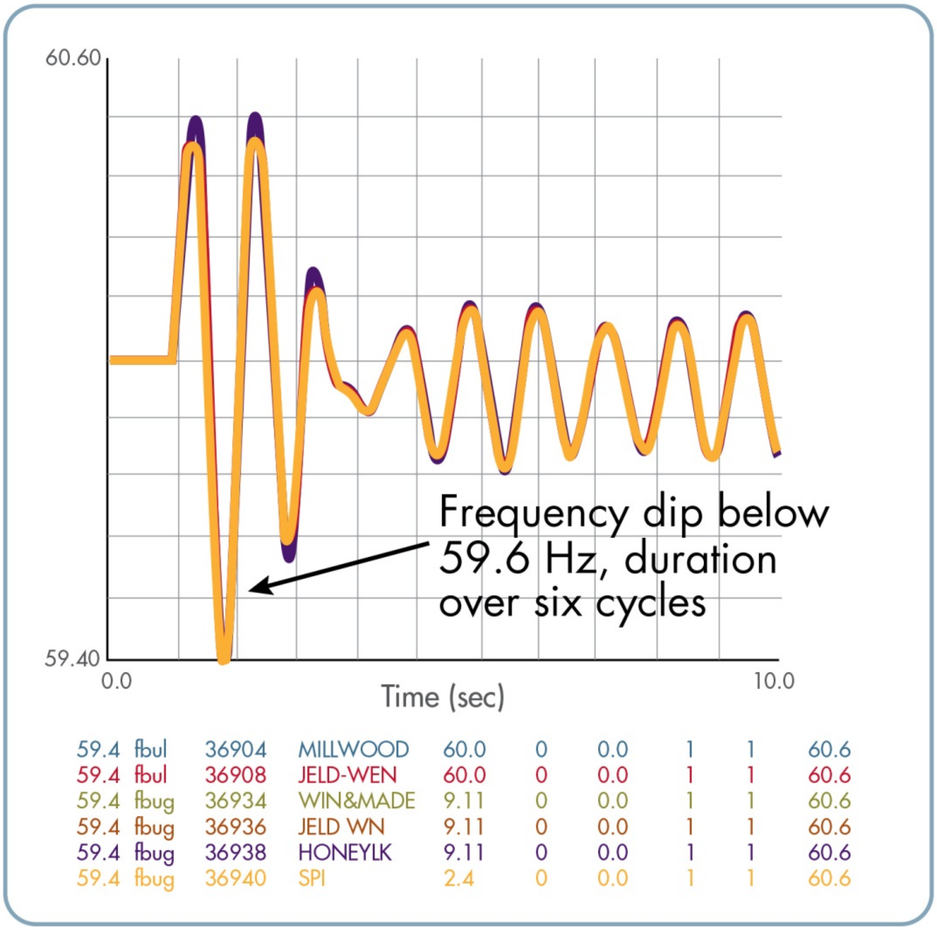
Figure 4.2:14: Table Mountain 500/230 kV transformer outage



In addition to the thermal overloads, an outage of the Table Mountain 500/230 kV transformer with a three-phase fault caused transient voltage and frequency criteria violations in the 115 kV and 60 kV systems in the Table Mountain area and around Quincy, Plumas and Feather River.

Tripping Hyatt and Thermalito generation by the existing SPS mitigates the overload and transient voltage dip, however, frequency criteria violations still remain. Figure 4.2:15 illustrates these concerns. This figure shows frequency plots with a three-phase fault on the 500 kV bus of the Table Mountain 500/230 kV transformer cleared by opening the transformer circuit breakers and the existing SPS applied. Six load buses with the lowest frequency are shown.

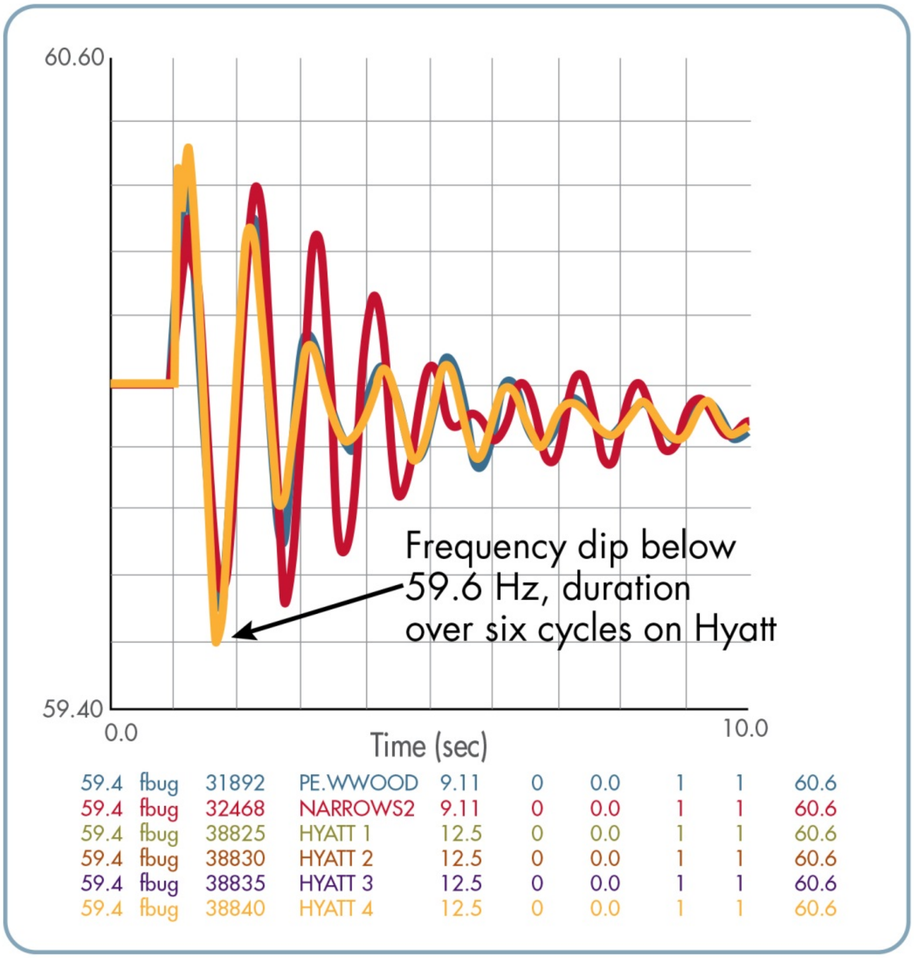
Figure 4.2:15: Frequency with Table Mountain transformer outage and existing SPS



Potential mitigation for the transient frequency concerns is to modify the Table Mountain transformer SPS so that this SPS would trip different units. Tripping Colgate, Poe, Butt Valley, Caribou 4, Forbs Town, De Sabla and Honey Lake generation instead of tripping Hyatt and Thermalito will mitigate both the overloads and the transient stability criteria violations. Total amount of the generation tripped by SPS will be approximately the same if the SPS is modified. In the case with high distributed generation, 657 MW was tripped from Hyatt and Thermalito by the existing SPS and 642 MW if the SPS is modified as described above. However, in such an extreme case as the one with high distributed generation, such modification to the SPS may not be sufficient. Even if the frequency performance significantly improved, there still were transient frequency criteria violations at the Hyatt power plant busses.

Figure 4.2:16 shows frequency on the six buses with lowest frequency for the Table Mountain transformer contingency in the High Distributed Generation portfolio and the SPS modified. As can be seen from the plot, the system performance significantly improved. In addition to the smaller frequency dip, the damping was also considerably better.

Figure 4.2:16: Frequency with Table Mountain transformer outage and modified SPS



In the High Distributed Generation portfolio the flow through the Table Mountain transformer was very high: 1,041 MW in the direction from 230 kV to 500 kV.

To mitigate the remaining frequency violations, power flow through the Table Mountain transformer should be limited. It can be achieved by congestion management, such as reducing generation output in the Table Mountain area. Limiting the flow through the Table Mountain 500/230 kV transformer in the direction from the 230 kV to the 500 kV to under 880 MW and modifying the SPS will eliminate all criteria violations.

4.2.4 Northern PG&E Policy-Driven Deliverability Assessment Results and Mitigations

Base Portfolio Deliverability Assessment Results

Deliverability assessment results for PG&E North area are shown in the table below.

Table 4.2-8: Base portfolio deliverability assessment results for PG&E North area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	Mitigation
Stockton ‘A’ 60 kV line #1	Normal	110%	Central Valley North	Localized concern. Should be addressed by generator interconnection process.
Stockton ‘A’-Weber 60 kV line #3	Normal	107%	Central Valley North	Localized concern. Should be addressed by generator interconnection process.
Trimble-San Jose ‘B’ 115 kV line	Los Esteros - Trimble & Los Esteros - Montague 115 kV	105%	Greater Bay Area DG	Localized concern. Should be addressed by generator interconnection process.
Cayetano-USWP-JRW 230 kV line	Contra Costa-Moraga Nos. 1&2 230 kV lines	102%	Solano CREZ	SPS

Deliverability of the new renewable resources in the Central Valley North area is limited by the overload on the Stockton ‘A’ #1 and Stockton ‘A’-Weber #3 60 kV lines. These overloads are localized issues and will be addressed in the generation interconnection process.

Deliverability of the new renewable resources in the Greater Bay Area DG is limited by the overload on the Trimble-San Jose ‘B’ 115 kV line. This overload is localized issues and will be addressed in the generation interconnection process.

Deliverability of the new renewable resources in the Solano CREZ is limited by the overload on the Cayetano-USWP-JRW 230 kV line. A SPS to trip either the Solano area or Contra Costa area generation will mitigate this overload.

Recommendation

The following transmission upgrade is needed for the base portfolio, plus at least one other portfolio:

- SPS for Cayetano-USWP_JRW 230 kV line.

This transmission upgrade is recommended as policy-driven upgrade.

Transmission Plan Deliverability with Recommended Transmission Upgrades

No area deliverability constraint identified in PG&E North area.

4.2.5 Southern PG&E Policy-Driven Deliverability Assessment Results and Mitigations

Deliverability assessment results for PGE south area are shown in the table below.

Table 4.2-9: Deliverability Assessment Results for PG&E South Area

Overloaded Facility	Contingency	Flow	Undeliverable Zone	Mitigation
Warnerville-Bellota 230 kV line	Normal	120%	Greater Fresno Area DG, Central Valley North, Merced, Westlands	Reconductor- Also identified in generator interconnection process
Los Banos-Westley 230 kV line	Normal	108%	Central Coast/Los Padres Area DG, Greater Fresno Area DG, Los Banos, Merced, Westlands	Localized concern. Should be addressed by generator interconnection process.
Wilson-Le Grand 115 kV line	Normal	103%	Greater Fresno Area DG, Merced, Westlands	Reconductor- Also identified in generator interconnection process.
Panoche-Schindler 115 kV line #2 (Cheney Tap-Panoche)	Normal	132%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.

Overloaded Facility	Contingency	Flow	Undeliverable Zone	Mitigation
Schindler-Huron-Gates 70 kV line (Huron Jct-Calflax)	Normal	112%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Arco-Carneras 70 kV line	Normal	101%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Moss Landing-Panoche 230 kV line (Moss Landing-TT22113)	Moss Landing - Coburn & Coburn - Panoche 230 kV Lines	101%	Central Coast/Los Padres Area DG, Greater Fresno Area DG, Los Banos , Merced, Westlands	Localized concern. Should be addressed by generator interconnection process.
Panoche-Schindler 115 kV line #1 (Westlands-Schindler)	Gates 230/70 kV Transformer #5	114%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Panoche-Schindler 115 kV line #2 (Cheney Tap-Schindler)	Panoche - Schindler #1 115 kV Line	123%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Wilson-Oro Loma 115 kV line (Oro Loma-El Nido)	Herndon - Kearney & Gates-Gregg 230 kV Lines	101%	Greater Fresno Area DG, Merced, Westlands	Reconductor or SPS
Gates 230/70 kV Bank #5	Panoche - Schindler #1 & #2 115 kV Lines	114%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.

Overloaded Facility	Contingency	Flow	Undeliverable Zone	Mitigation
Coalinga1-Coalinga2 70 kV line (Coalnga1-Tornado)	Panoche - Schindler #1 115 kV Line	110%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
\Gates-Coalinga2 70 kV line (Gates Tap-Gates)	Gates 230/70 kV Transformer #5	104%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Schindler-Huron-Gates 70 kV line (Calflax-Schindler)	Gates 230/70 kV Transformer #5	110%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Schindler-Huron-Gates 70 kV line (Huron-Huron Jct)	Panoche - Schindler #1 & #2 115 kV Lines	120%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Schindler-Coalinga #2 70 kV line (Schindler-Pleasant Valley)	Panoche - Schindler #1 115 kV Line	114%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.
Coalinga1-San Miguel 70 kV line	Gates 230/70 kV Transformer #5	119%	Greater Fresno Area DG, Westlands	Localized concern. Should be addressed by generator interconnection process.

PGE south area consists of the following renewable zones- Carrizo south, Los Banos, Merced, Westland, Non CREZ Central Coast/ Los Padres, Central Coast/Los Padres DG and Greater Fresno Area DG.

The deliverability of the proposed renewable generation in the PGE south area was limited by several normal and emergency overloads. ISO is recommending transmission upgrades for the following overloads seen in the analysis:

1.) The normal overload on the Bellota-Warnerville 230 kV line severely restricted the deliverability of the generators in the area for various portfolios. Please refer to Table 4.2-9 above for details. This overload can be mitigated by reconductoring the 230 kV line or adding a line reactor.

2.) The normal overload on Wilson-LeGrand 115 kV line restricts the deliverability of certain renewable zones in PGE south area for various portfolios. Please refer to Table 4.2-9 above for details. This overload can be mitigated by reconductoring the 115 kV line.

The remaining overloads in the PGE south area are localized in nature and should be addressed by the generator interconnection process.

Analysis of Other Portfolios

The need for transmission upgrades identified above is analyzed for other renewable portfolios by comparing the generation behind the deliverability constraint. The results are shown in Table 4.2-10. The generation capacity listed for each renewable zone represents only the generators contributing to the deliverability constraint and may be lower than the total capacity in the renewable zone.

Table 4.2-10: Portfolios Requiring the Transmission Upgrade

Transmission Upgrade	Renewable Zones	Com. Interest (MW)	High DG (MW)	Env. (MW)	Cost (MW)	Needed for Portfolios
Warnerville-Bellota 230 kV line	Fresno Area DG, Central Valley North, Merced, Westlands	3,548	2,942	3,824	3,132	Com. Interest, Cost Constr., Env.
Wilson-Le Grand 115 kV line	Greater Fresno Area DG, Merced, Westlands	2,278	2,042	2,554	2,233	Com. Interest, Cost Constr., Env.

Recommendation

The following two transmission upgrades are needed for the base portfolio, and at least one other portfolio:

- reconductor the Warnerville-Bellota 230 kV line; and
- reconductor the Wilson-Le Grand 115 kV line.

These two transmission upgrades are recommended for approval as policy-driven upgrades.

4.2.6 PG&E Area Policy-Driven Conclusions

As per 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 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 (RPS study) for the PG&E North area did not identify any new transmission additions or upgrades that qualify as Category 1 or Category 2.

The power flow studies for the PG&E North area showed that the existing transmission system is adequate to accommodate additional renewable generation assumed to be developed in the four portfolios. As discussed earlier in the report the PG&E North study area includes Humboldt, North Coast, North Bay, North Valley, Central Valley and the Greater Bay areas. Various thermal and voltage issues have been identified in the RPS study of these areas which have also been seen in the reliability analysis as discussed in chapter 2 of this report. Mitigations developed in the reliability analysis have been used for any common issues between the reliability analysis and RPS analysis which become incrementally worse in the RPS study. Additional mitigations have been used only when the mitigation identified in the reliability analysis was found to not sufficiently mitigate the violation in the RPS study.

In the Humboldt area, the new Bridgeville-Garberville 115 kV Transmission Line project that was approved last year was found to mitigate the thermal and voltage concerns that may be aggravated by additional renewable generation projects. Additionally maintaining a certain dispatch level of the existing Humboldt Bay Power Plant was found to be necessary to mitigate some of the thermal and voltage concerns seen in the RPS study cases.

In the North Coast and North Bay areas the studies identified voltage and voltage deviation violations under certain contingency conditions. These violations can be mitigated by requiring all renewable generators in the area, 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.

In the North valley area the Trinity-Cascade 60 kV lines were found to be overloaded in the environmentally-constrained and High DG portfolio cases. These are localized concerns for which mitigation will be developed through the generator interconnection process. Similarly, in the Central Valley area some 60 kV lines in the Stockton area as well as some 115 kV line in the Tesla-Salado area were found to be overloaded in Commercial Interest, Cost Constrained and High DG portfolio cases. These were also found to be localized concerns and will be addressed in the generator interconnection process.

In the Greater Bay Area thermal violations were found on the Metcalf - Morgan Hill 115 kV line as well as the Llagas - Morgan Hill 115 kV line. These overloads can be mitigated by using congestion management (pre-dispatching of generation). Alternatively, these lines can also be upgraded, if found necessary to reduce the need for congestion management in the area. New renewable projects in this area would be required to provide 0.95 lead/lag power factor capability to avoid excessively low voltages.

The deliverability analysis for the PG&E North area found that the Cayetano – USWP JRW 230 kV line was overloaded under Category C contingency conditions. This thermal constraint would make the generation in the Solano CREZ undeliverable. ISO recommends PG&E to install an SPS to trip either the Solano area generation or the Contra Costa area generation to mitigate this constraint.

The power flow studies for the PG&E South area identified several thermal and voltage issues on the system. PGE south area consists of the following renewable zones: Carrizo south, Los Banos, Merced, Westland, NON CREZ Central Coast/ Los Padres, Central Coast/Los Padres DG and Greater Fresno Area DG.

In the Fresno area, thermal and voltage issues were seen in all portfolios. Most of these issues, however, are localized concerns that will be resolved through the generator interconnection process. The Wilson – Le Grand 115 kV and Dairyland – Le Grand 115 kV lines were found to be overloaded under Category C1 contingencies in the Cost, Commercial and Environmentally Constrained portfolios under peak load conditions. Wilson-Le Grand was also constrained under a C1 contingency during off-peak conditions. Reconductoring these 115 kV line sections would alleviate the violation.

In the Los Padres area, as the Mesa and Divide 115 kV system is a generation deficient area, the study shows that introduction of the renewable generation in the area improves system operations under both the normal and contingency conditions. Overall, the area could also benefit from an additional source and thus reduce the dependence on the Mesa 230 kV source to serve the area. The study identified thermal overloads on the Morro Bay-Solar Switching Station 230 kV #1 and #2 lines as well as the San Luis Obispo-Carrizo 115 kV #1 Line, which can be mitigated through installing SPS. Alternatively the generators can also be relocated to avoid the overload. The study also identified voltage issues on some renewable generator busses which will require those generators meet the +/- 0.95 power factor standard.

The deliverability analysis for the PG&E South area found that the renewable generation in the four portfolios is constrained by several normal and emergency overloads. Several of the overloads found in the deliverability analysis were localized problems which will be addressed in the generator interconnection process. The Bellota-Warnerville 230 kV line as well as the Wilson – Le Grand 115 kV lines were found to be normally overloaded (Category A) and were severely constraining the deliverability of the generators in the area in the base, Cost constrained and environmentally constrained portfolios. Generators in the Fresno area DG, Merced, Westlands and Central Valley north (only for Bellota – Warnerville 230 kV line) renewable zones were found to be constrained for these overloads. These two transmission upgrades have been identified as being required as policy-driven project. The ISO is recommending the reconductoring of the Bellota – Warnerville 230kV line and the Wilson – Le Grand 115 kV line to mitigate the deliverability constraints. As per ISO tariff section 24.4.6.6, these two upgrades will be approved by the ISO as category 1 upgrades.

The PG&E bulk transmission system analysis did not identify any thermal overloads in the policy-driven studies under normal system conditions. However, two transmission facilities, Midway-Gates 500 kV line and Table Mountain 500/230 kV transformer, were loaded above 98 percent of their normal ratings under off-peak conditions in some scenarios. The peak load studies identified three 230 kV emergency line overloads (Delevan-Cortina, Westley-Los Banos and Moss Landing-Panoche 230 kV lines) that can be mitigated by congestion management and installing SPS to trip generation for Category B and C contingencies. The off-peak studies identified emergency overloads on two of these transmission lines (Westley-Los Banos and Moss Landing-Panoche 230 kV lines) and also emergency overloads on three more 230 kV transmission lines in the Fresno and Kern areas (Kearney-Herndon, Gates-Midway and Arco-Midway 230 kV lines). In addition, three 500/230 kV transformers (Round Mountain, Table Mountain and Olinda) are expected to overload with Category B and C contingencies under off-peak conditions. The off-peak overloads may be mitigated by congestion management and SPS. One transmission line section (of the Westley-Los Banos 230 kV line) is planned to be upgraded through the generation interconnection process.

The studies of the extreme events (Category D contingencies) did not identify any cascading outages if the appropriate remedial actions, such as generation and load tripping are applied. Transient stability studies identified frequency concerns with an outage of the Table Mountain 500/230 kV transformer under off-peak load conditions. These concerns can be mitigated by modifying the existing SPS and congestion management.

Overall the results of the bulk system analysis in 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.

4.3 Policy-Driven Assessment in SCE Area

This section presents the policy-driven assessment results 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, 2022 peak and off-peak load scenarios were studied (except for peak High DG). The deliverability assessment was performed on base portfolio.

The study was performed based on the general study methodology and assumptions described in previous sections. Specific assumptions applied to the SCE area are provided below.

Table 4.3-1 summarizes the renewable generation capacity modeled to meet the RPS net short in the SCE system in each portfolio by renewable energy zone.

Table 4.3-2 shows the generation output from the new renewable generators in each portfolio.

Table 4.3-1: Renewable generation installed capacity in the SCE system modeled to meet the 33% RPS net short

Zone	High DG (MW)	Environmentally Constrained (MW)	Commercial Interest (MW)	Cost Constrained (MW)
Kramer	62	64	765	62
DG	2,995	1,978	487	599
Eldorado	750	0	750	250
Mountain Pass	665	365	665	1,045
Non CREZ	103	114	107	109
Palm Springs	83	198	198	188
Riverside East	1,510	1,364	1,506	1,867
San Bernardino – Lucerne	187	108	106	271
Tehachapi	2,429	3,375	3,395	4,566
Total SCE	**8,784**	**7,566**	**7,979**	**8,957**

Table 4.3-2: New Renewable generation output for power flow and stability studies in SCE areas

Portfolio	Renewable Capacity (MW)	Output on peak (MW)	Output off-peak (MW)
High DG	8,784	N/A	6,653
Environmentally Constrained	7,566	4,573	6,995
Commercial Interest	7,979	4,991	7,398
Cost Constrained	8,957	5,484	8,236

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 an LGIA and CPUC approval and is under construction. 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 planned 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 completion date for this upgrade was initially estimated to be early 2018. However, the completion of West of Devers could be delayed by at least a year, and possibly longer, considering the potential long lead time to obtain transmission rights-of-way and to submit the application for a Certificate of Public Convenience and Necessity to the CPUC, and to obtain regulatory approval for the project and to comply with environmental mitigation measures that may be imposed by the regulatory authorities.

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 lines. The project has ISO and CPUC approval, and is currently in process of rehearing of Segment 8. The proposed in-service date is 2015.

Devers-Mirage 230 kV Lines Upgrade

The project consists of SCE’s portion of the Path 42 project, which includes reconductoring the Devers-Mirage 230 kV transmission line. The project has ISO approval and engineering work is currently underway. The proposed in-service date is 2014.

Path 42 project also consists of IID’s portion, which includes upgrading the Coachella Valley-Mirage 230 kV transmission line and upgrading the Coachella Valley - Ramon-Mirage 230 kV transmission line.

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 2015.

4.3.1 SCE Policy-Driven Powerflow and Stability Assessment Results and Mitigations

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 was found to materially increase. The discussion includes proposed mitigation plans for the system performance concerns identified.

Thermal Overloads

Coolwater 115 kV-TT22409 115 kV #1 line

The Coolwater 115 kV-TT22409 115 kV #1 line was overloaded under normal conditions with all facilities in service. The overloading occurred in both off-peak and peak Commercial Interest portfolios and is caused by new renewable connected to the TT22409 115 kV interconnection point. This is a localized concern that should be addressed by generator interconnection process.

Control 115 kV-Inyo 115 kV #1 and Inyo 115 kV-Inyo PS 115 kV #1 lines

The Control 115 kV-Inyo 115 kV #1 and Inyo 115 kV-Inyo PS 115 kV #1 lines were overloaded under normal conditions with all facilities in service. The overloading occurred in both off-peak and peak Commercial Interest portfolios. Upgrading INYO phase shifter was previously identified in generator interconnection process and would address this concern. This is a localized concern that should be addressed by generator interconnection process.

Inyokern 115 kV-Kramer 115 kV #1 line

The Inyokern 115 kV-Kramer 115 kV #1 line was overloaded under normal conditions with all facilities in service. The overloading occurred in peak Commercial Interest portfolio. Installing SVD in Inyokern area or reconductoring Inyokern 115 kV-Kramer 115 kV would address this concern. This is a localized concern that should be addressed by generator interconnection process.

Eldorado2 230 kV-Bob Tap 230 kV #1 line

The Eldorado2 230 kV-Bob Tap 230 kV #1 line was overloaded following a T-1 outage of Eldorado 500 kV-Eldorado2 230 kV #1 transformer. The overloading occurred in both off-peak and peak cost constrained portfolio. SPS to trip new renewables in the Ivanpah area would address this concern and was proposed in previously conducted generator interconnection studies. This is a localized concern that should be addressed by the generator interconnection process.

Julian Hinds SCE 230 kV-Mirage 230 kV # 1 and Julian Hinds MWD 230 kV - Julian Hinds SCE 230 kV # 1 lines

Julian Hinds SCE 230 kV-Mirage 230 kV # 1 and Julian Hinds MWD 230 kV - Julian Hinds SCE 230 kV # 1 lines were overloaded following L-2 outage of Devers 230 kV-Mirage 230 kV #1 and #2 lines. Both lines were overloaded in the off-peak Cost Constrained portfolio. The contingency also resulted in diverged power flow solution concerns for peak Environmentally Constrained and all other off-peak portfolios. IID is currently working on Path 42 SPS that would address this concern. This is a localized concern that should be addressed by generator interconnection process.

Eldorado 500 kV-Lugo 500 kV # 1 line

The Eldorado 500 kV-Lugo 500 kV # 1 line was overloaded following a L-2 outage of McCullough 500 kV-Victorville 500 kV # 1 and # 2 lines. The overloading occurred in peak Cost Constrained and Commercial Interest portfolio. Upgrading Eldorado 500 kV-Lugo 500 kV #.1 series cap was identified in Cluster C3 C4 Phase II and would address the concern.

Lugo 500 kV- Victorville 500 kV # 1 line

The Lugo 500 kV-Victorville 500 kV # 1 line was overloaded following a L-2 outage of Eldorado 500 kV-Lugo 500 kV # 1 and Mohave 500 kV-Eldorado 500 kV # 1 or Eldorado 500 kV-Lugo 500 kV # 1 and Lugo 500 kV-Mohave 500 kV # 1 lines. The overloading occurred in all peak portfolios. For former outage, recommended mitigation is to reconfigure Eldorado-Lugo 500 kV line to classify outage as L-1-1. For the latter outage, recommended mitigation is to maintain WECC Category D classification for the outage, but also consider SPS to trip gen at Eldorado.

Windhub 230 kV-Windhub 66 kV # 1 or # 2 line

The Windhub 230 kV-Windhub 66 kV # 2 or # 1 transformer was overloaded following a T-1 outage of Windhub 230 kV-Windhub 66 kV # 1 or # 2 line. The overloading occurred in off-peak Cost Constrained portfolio. SPS to trip new renewables in Windhub area was proposed in previously conducted generator interconnection process studies and would address this concern. This is a localized concern that should be addressed by the generator interconnection process.

Control 115 kV-Inyokern 115 kV # 1 and Control 115 kV-Coso 115 kV-Inyokern 115 kV # 1 lines

The Control 115 kV-Inyokern 115 kV # 1 and Control 115 kV-Coso 115 kV-Inyokern 115 kV # 1 lines were overloaded following a L-1 outage of Control 115 kV-Inyo 115 kV # 1 or Inyo 230 kV-Cottonwood 230 kV # 1 or Inyo 115 kV-Inyo PS 115 kV # 1 line. The overloading occurred in off-peak Commercial Interest portfolio. SPS to trip new renewables in the Control area would address this concern. This is a localized concern that should be addressed by the generator interconnection process.

Voltage Concerns

Dunn Siding 115 kV

Voltage at Dunn Siding 115 kV exceeded the applicable high voltage limit of 1.05 p.u. under normal conditions in both peak and off-peak Commercial Interest portfolios. The high voltage is caused by new renewable connected to the TT22409 115 kV interconnection point. This is a localized concern that should be addressed by the generator interconnection process.

Ivanpah area power flow case divergence

Ivanpah 230 kV-Eldorado2 230 kV #1 line contingency resulted in diverged power flow solution concerns. The divergence occurred in all off-peak and peak portfolios. SPS to trip new renewables in the Ivanpah area would address this concern and was proposed in previously conducted generator interconnection studies. This is a localized concern that should be addressed by the generator interconnection process.

Mirage area power flow case divergence

Coachella Valley 230 kV-Mirage 230 kV #1 and Ramon 230 kV-Mirage 230 kV # 1 or Coachella Valley 230 kV-Mirage 230 kV #1 and Coachella Valley 230 kV-Ramon 230 kV #1 lines contingency resulted in diverged power flow solution concerns. The divergence occurred in all off-peak and peak portfolios. IID is currently working on Path 42 SPS that would address this concern. This is a localized concern that should be addressed by the generator interconnection process.

Kramer area power flow case divergence

Kramer 230 kV-Lugo 230 kV # 1 and #2 lines contingency resulted in diverged power flow solution concerns in off-peak and peak Commercial Interest portfolios. Coolwater-Lugo 230 kV line which is also identified in the generator interconnection process would address this concern. Also AV Clearview project could mitigate the concern. Expansion of Kramer RAS may not be feasible due to hardware concerns.

Inyokern 115 kV, Randsburg 115 kV, Coso 115 kV, and Downs 115 kV buses

Low voltage and voltage deviation concerns were identified at Inyokern 115 kV, Randsburg 115 kV, Coso 115 kV, and Downs 115 kV buses following an L-1 contingency of Inyokern 115 kV-Kramer 115 kV # 1 line in the peak Commercial Interest portfolio. In addition, voltage deviation concerns were identified at Inyokern 115 kV, Randsburg 115 kV, and Downs 115 kV buses following the contingency in the off-peak Commercial Interest portfolio. The issue can be mitigated by installing a static voltage device (SVD) in Inyokern 115 kV area. This is a localized concern that should be addressed by the generator interconnection process.

Coso 115 kV and Inyokern 115 kV buses

Low voltage and voltage deviation concerns were identified at Coso 115 kV bus following an L-1 contingency of Control 115 kV-Inyo 115 kV # 1 or Inyo 230 kV-Cottonwood 230 kV # 1 or Inyo 115 kV-Inyo PS 115 kV # 1 line in the off-peak and peak Commercial Interest portfolios. In addition, voltage deviation concerns were identified at Inyokern 115 kV bus following the contingency in the off-peak Commercial Interest portfolio. The issue can be mitigated by SPS tripping Control area generation. This is a localized concern that should be addressed by the generator interconnection process.

Inyo 115 kV and Inyo PS 115 kV buses

Voltage deviation concerns were identified at Inyo 115 kV bus following an L-1 contingency of Owenscon 230 kV-Inyo 230 kV # 1 line in the off-peak and peak Commercial Interest portfolios. In addition, voltage deviation concerns were identified at Inyo PS 115 kV bus following the contingency in all off-peak portfolios. The issue can be mitigated by SPS tripping Control area generation. This is a localized concern that should be addressed by the generator interconnection process.

Eldorado2 230 kV, Ivanpah 230 kV, Baker 115 kV, Bob Tap 230 kV, Crazy Eye Tap 230 kV, VEA_Q13 230 kV, and VEA_Q14 230 kV buses

Voltage deviation concerns were identified at Eldorado2 230 kV, Ivanpah 230 kV, Bob Tap 230 kV buses following T-1 contingency of Eldorado 500 kV–Eldorado2 230 kV # 1 transformer in the off-peak and peak cost constrained portfolios. In addition, voltage deviation concerns were identified at Baker 115 kV, Crazy Eye Tap 230 kV, VEA_Q13 230 kV, and VEA_Q14 230 kV buses following the contingency in the peak cost constrained portfolio. The issue can be mitigated by SPS tripping Control area generation. This is a localized concern that should be addressed by the generator interconnection process.

Tehachapi area 66 kV

Voltage deviation concerns were identified at numerous Tehachapi area 66 kV buses following an T-1 contingency of Windhub 230 kV-Windhub 66 kV # 1 or # 2 transformer in the off-peak Commercial Interest portfolio. The issue can be mitigated by SPS to trip new renewables in Windhub area and was also proposed in previously conducted generator interconnection process studies. This is a localized concern that should be addressed by the generator interconnection process.

4.3.2 SCE Area Policy-Driven Deliverability Assessment Results and Mitigations

Base Portfolio Deliverability Assessment Results

Deliverability assessment results for SCE area are shown in the table below.

Table 4.3-3: Base portfolio deliverability assessment results for SCE area

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Inyo 115 kV phase shifter	Base Case	152%	Nevada C	Upgrade Inyo phase shifter (this upgrade is in an LGIA)
Control - Inyo 115 kV No. 1	Base Case	106%	Kramer (Control)	
Lugo - Kramer 230 kV No. 1	Base Case	115%	Nevada C Kramer	Coolwater - Lugo 230 kV line (this upgrade is in an LGIA) or AV Clearview Transmission Project
Lugo - Kramer 230 kV No. 2	Base Case	115%		
Kramer 230/115 kV No. 1	Lugo - Kramer 230 kV No. 1 & No. 2	108%	Kramer (Coolwater)	Coolwater - Lugo 230 kV line or AC Clearview Transmission Project
Coolwater - Dunn Siding Loop 115 kV No. 1	Base Case	222%	Kramer (Coolwater 115) Mountain Pass	Reconductor Coolwater - Dunnsiding loop 115 kV line

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Tortilla - Coolwater - SEGS2 115 kV No. 1	Kramer - Coolwater 115 kV No. 1	119%	Kramer Lucerne Mountain Pass	SPS to trip gen
Kramer - Coolwater 115 kV No. 1	Tortilla - Coolwater - SESG2 115 kV No. 1	119%		
Kramer 230/115 kV No. 1	Kramer - Victor - Roadway 115 kV No. 1 & No. 2	102%		
Lugo - Eldorado 500 kV No. 1	Lugo - Victorville 500 kV No. 1	110%	Mountain Pass Eldorado Riverside East Tehachapi (230 kV) SDGE	Lugo - Eldorado series cap and terminal equipment upgrade (identified in Cluster 3 and 4 Phase II generator interconnection study)
	Red Bluff - Colorado River No. 1 & 2	110%		
	Devers - Red Bluff 500 kV No. 1 & 2	114%		
Mccullough - Victorville 500 kV No. 1	Base Case	101%		
Mccullough - Victorville 500 kV No. 2	Base Case	100%		
Lugo - Victorville 500 kV No. 1	Devers - Red Bluff 500 kV No. 1 & 2	106%		
	Red Bluff - Colorado River No. 1 & 2	102%		
Lugo - Victorville 500 kV No. 1	Lugo - Eldorado 500 kV No. 1 & Eldorado - Mohave 500 kV No. 1	115%	Eldorado Tehachapi (230 kV) SDGE	Re-route Lugo - Eldorado 500 kV line (identified in Cluster 3 and 4 Phase II generator interconnection study)
Pahrump 230/138 kV No.1	Bob Tap – Crazy Eye 230 kV No. 1	101%	Eldorado (VEA)	SPS to trip generation (identified in Cluster 3 and 4 Phase II

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
	Bob Tap – Mead 230 kV No. 1 and Bob Tap – Eldorado 230 kV No. 1	102%		generator interconnection study)
J. Hinds - Mirage 230 kV No. 1	Base Case	101%	Riverside East (Blythe)	Upgrade Julian Hinds – Mirage 230 kV line or other mitigation measures

Deliverability of the new renewable resources in the Control area is limited by the overload on Inyo phase shifter and Inyo – Control 115 kV line. Upgrading the Inyo phase shifter to +/-60 degree angle regulation could control the normal condition flow from Control to Inyo below 20MW, thus mitigate the overloads. This mitigation is currently identified in an LGIA. It is also very localized in nature and should be addressed through generator interconnection process.

Deliverability of the new renewable resources north of Kramer is limited by the normal overloads on Kramer – Lugo 230 kV lines. Building a new Coolwater – Jasper 230 kV line and rebuilding Jasper – Lugo 230 kV provide another path from north of Kramer to Lugo and mitigate the overloads. Alternatively, the proposed AV Clearview Transmission Project could also mitigate the normal condition overloads. The Coolwater-Jasper 230 kV line and Jasper-Lugo 230 kV upgrades are currently in LGIAs and are currently in the permitting application phase.

In the base portfolio, there are 230MW new renewable resources delivering their output to the ISO Control Grid at a loop-in substation to the Coolwater – Dunnsiding – Baker – Mountain Pass 115 kV line. Their deliverability is limited by the normal overloads from Coolwater to the loop-in substation. To mitigate the overload, the Coolwater to loop-in substation 115 kV line needs to be reconductored. These resources also cause various contingency overloads in the Coolwater and Kramer area. An SPS needs to be implemented to trip the generators under the outage conditions. These upgrades are very localized in nature and should be addressed through the generator interconnection process.

Overloads on 500 kV facilities from McCullough to Victorville outside of the ISO balancing authority area were observed under normal condition and Category C outage along the Colorado River to Devers transmission corridor. To reduce flow through the neighboring systems and mitigate the overloads, the series compensation level on the Lugo – Eldorado 500 kV line needs to be increased from 35 percent to 70percent by switching in the series capacitor at Eldorado. However, overload on the Lugo – Eldorado 500 kV line was identified under Category B and Category C outage conditions. Switching in the series cap would further aggravate the overload on the Lugo – Eldorado 500 kV line. The rating of the line is limited by the series capacitors and terminal equipment. The series capacitors and terminal equipment needs to be upgraded to higher rating of 3,800 Amps. These upgrades were identified in the cluster 3 and 4 Phase II in the generator interconnection process study. However, they are needed by a large quantity of generation projects spread across a large geographic area. This upgrade should be considered for approval as a policy-driven upgrade through transmission planning process.

The double outage of Lugo – Eldorado 500 kV line and Eldorado – Mohave 500 kV line causes significant overloading on the Lugo – Victorville 500 kV line. The Lugo – Eldorado 500 kV line and the Eldorado – Mohave 500 kV line are adjacent transmission circuits for about 4.8 miles. By rerouting the Lugo – Eldorado 500 kV such that they are not adjacent for more than 3 miles, the outage is no longer common mode contingency. System adjustment could be made after the first outage to prevent overload following the second outage. These upgrades were identified in the Cluster 3 and 4 Phase II of the generator interconnection process study. However, they are needed by a large number of generation projects spread across a large geographic area. This upgrade should be considered for approval as a policy-driven upgrade through the transmission planning process.

The Pahrump 230/138 kV transformer bank is overloaded under Category B and Category C outage conditions. An SPS would be needed to trip generators in the Valley Electrical Association area.

Overloads of Julian Hinds – Mirage 230 kV line under normal conditions are caused by the local generation modeled in the Blythe area. Additional generation in the area from the portfolios may require upgrading the line between Julian Hinds and Mirage 230 kV substations or other mitigation measures. The constraint is localized in nature and should be addressed in generation interconnection studies.

Analysis of Other Portfolios

The need for transmission upgrades identified above is analyzed for other renewable portfolios by comparing the generation behind the deliverability constraint. The results are shown in the table below. The generation capacity listed for each renewable zone represents only the generators contributing to the deliverability constraint and may be lower than the total capacity in the renewable zone.

Table 4.3-4: Portfolios Requiring the Transmission Upgrade

Transmission Upgrade	Renewable Zones	Commercial Interest (MW)	High DG (MW)	Env. Constrained (MW)	Cost Constrained (MW)	Needed for Portfolios
Upgrade Inyo phase shifter	Nevada C	26	26	0	26	Commercial Interest
	Kramer (Control)	64	0	0	0	
Coolwater - Lugo 230 kV line or AV Clearview Transmission Project	Nevada C	26	26	0	26	Commercial Interest
	Kramer	764	62	63.5	62	
Reconductor Coolwater - Dunnsiding loop 115 kV line	Kramer (Coolwater 115)	230	0	0	0	Commercial Interest
	Mountain Pass	665	665	365	1,045	
Lugo - Eldorado series cap and terminal equipment upgrade	Mountain Pass	665	665	365	1,045	Commercial Interest Cost Constrained
	Eldorado	750	750	0	750	
	Riverside East	1,505.7	1510	1,363.7	1,867	
	Tehachapi (230 kV)	164	400	185	172	
	Nevada C	26	26	0	26	
	Kramer (Control)	64	0	0	0	
	SDGE	2,377	1,277	2,298	1,576	
Re-route Lugo - Eldorado 500 kV line	Eldorado	750	750	0	750	Commercial Interest High DG Cost Constrained
	Tehachapi (230 kV)	164	400	185	172	
	Nevada C	26	26	0	26	
	SDGE	2,377	1,277	2,298	1,576	

Recommendation

The following two transmission upgrades are needed for the base portfolio, plus at least one other portfolio:

- Lugo – Eldorado series cap and terminal equipment upgrade; and
- re-route Lugo – Eldorado 500 kV line.

These upgrades also relieve previously identified area deliverability constraints and are recommended for approval as Category 1 policy-driven upgrades.

Transmission Plan Deliverability with Recommended Transmission Upgrades

With the above recommended transmission upgrades, an estimate of the generation deliverability supported by the existing system and approved transmission upgrades is listed in Table 4.3-5. The Deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints.

Table 4.3-5: Deliverability for Area Deliverability Constraints in SCE Area

<table>
<tr><th>Area Deliverability Constraint</th><th>Renewable Zones</th><th>Deliverability (MW)</th></tr>
<tr><td rowspan="5">East of River/West of River 500 kV line flow limits</td><td>Mountain Pass</td><td rowspan="5">7,900 – 11,700</td></tr>
<tr><td>Eldorado</td></tr>
<tr><td>Palm Springs</td></tr>
<tr><td>Riverside East
Tehachapi (230)
Nevada C</td></tr>
<tr><td>SDGE</td></tr>
<tr><td rowspan="3">Valley - Serrano flow limits</td><td>Riverside East</td><td rowspan="3">6,400 – 11,400</td></tr>
<tr><td>Palm Springs</td></tr>
<tr><td>Imperial</td></tr>
<tr><td rowspan="3">Mohave - Lugo flow limit</td><td>Mountain Pass</td><td rowspan="3">1,000 – 3,700</td></tr>
<tr><td>Eldorado</td></tr>
<tr><td>Riverside East (Palo Verde)</td></tr>
<tr><td>Pisgah - Lugo flow limits</td><td>Pisgah</td><td>600 - 700</td></tr>
</table>

	Lucerne	
Lugo AA Bank capacity limit	Nevada C	~1,200
	Kramer	
	Lucerne	
	Pisgah	
Kramer - Lugo flow limits	Nevada C	700 – 1,100 (with new Coolwater – Lugo 230 kV line)
	Kramer	
	Lucerne	
South of Vincent interface flow limit	Tehachapi	~18,900
	PG&E	

4.3.3 SCE Area Policy-Driven 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 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 renewable generation portfolios with some additional upgrades.

Some system performance issues requiring mitigation were identified in the North of Lugo area. Installing new static voltage devices, modifying or creating new SPS, upgrading phase shifter, upgrading series cap, reconfiguring line, power factor control, and modifying shunt switching scheme is required to prevent congestion and voltage concerns. In addition, Coolwater-Lugo or AV Clearview project were also presented as alternatives to the Kramer RAS as its expansion may not be feasible because of hardware limits. The table below provides the summary of the ISO proposed mitigations for policy-driven studies.

Table 4.3-6: Summary of ISO proposed mitigation for policy-driven studies

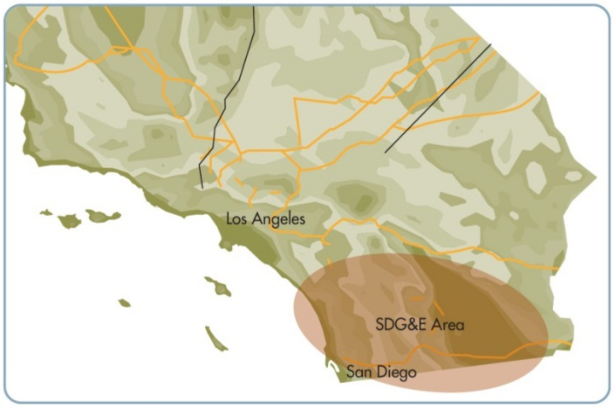
ISO Proposed Mitigation	High DG	Environmentally Constrained	Commercial Interest	Cost Constrained
Reconfigure Eldorado – Lugo 500 kV to classify outage as L-1-1	X	X	X	X
Upgrade series cap Eldorado - Lugo 500 kV	-	-	X	X

According to ISO tariff section 24.4.6.6 concerning policy-driven elements says 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 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 identify new transmission additions or upgrades that qualify as Category 1 or Category 2 elements.

Transmission upgrades Lugo - Eldorado series cap and terminal equipment upgrade, re-route Eldorado - Lugo 500 kV line are needed in the base portfolio are needed for base portfolio plus at least one other portfolio. These two upgrades also relieve previously identified area constraints and therefore are recommended for approval as Category 1 policy-driven upgrades.

4.4 Policy-Driven Assessment in SDG&E Area



The geographical location of SDG&E system is shown in the diagram below and the system configuration overview is shown in Figure 4.4:1. The major transmission upgrade in the SDG&E system modeled in the policy-driven assessment is the Sunrise Powerlink 500 kV transmission line. The ECO 500 kV Substation, which the Imperial Valley-Miguel 500 kV line will loop into, is also modeled in the base cases.

The points of import in 2022 will be the South of San Onofre (SONGS) transmission path (WECC Path 44), the Miguel 500/230 kV Substation, Suncrest 500/230 kV Substation and the Otay Mesa-Tijuana 230 kV transmission line.

The CREZs that have a direct impact on the SDG&E system are San Diego South, Imperial – SDG&E, Imperial – IID, Arizona and Baja as shown in the figure below.

Figure 4.4:1: Illustration of San Diego area

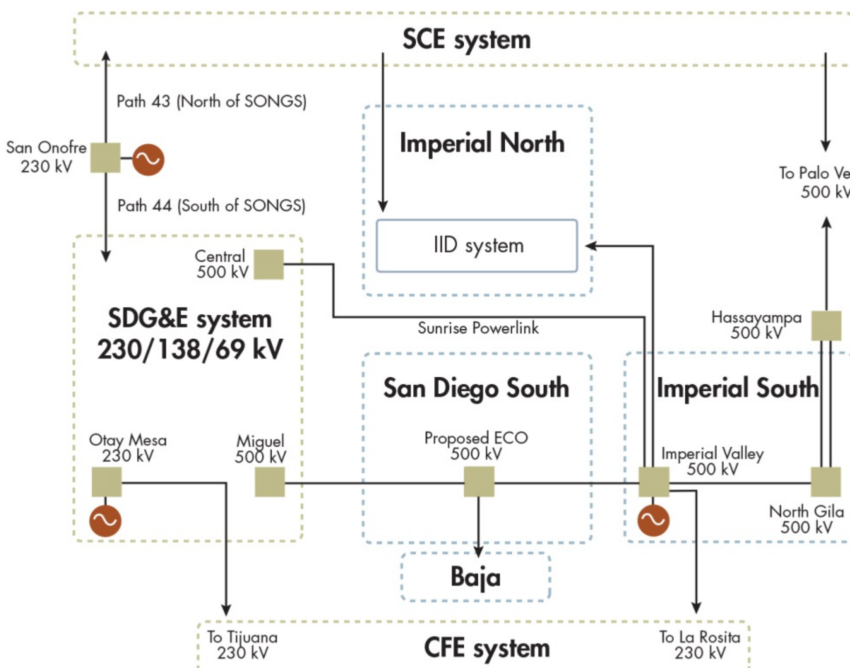


Table 4.4-1 shows the renewable generation levels modeled in the San Diego area in all four portfolios. Table 4.4-2: Summary of renewable generation in the San Diego area shows the renewable generation by portfolios in the San Diego area.

Table 4.4-1: Summary of renewable generation in the San Diego area

Zone	Renewable Generation by Portfolio (MW)			
	Cost Constrained	Commercial Interest	Environmental	High DG
Imperial – SDGE	220	921	921	220
Imperial – IID	920	1,219	1,219	920
San Diego South	384	384	384	0
Baja	0	100	0	0
Arizona	550	550	550	550
Non-CREZ – SDGE	17	17	17	17
SDGE DGs	405	405	426	490

Table 4.4-2: Summary of renewable generation in the San Diego area

Portfolio	Renewable Capacity (MW)	Output on peak (MW)	Output off-peak (MW)
Cost Constrained	1,524	822	1,258
Commercial Interest	2,624	1,161	1,920
Environmental	2,524	1,161	1,875
High DG	1,140	N/A	885

4.4.1 SDG&E Area Policy-Driven Powerflow and Stability Assessment Results and Mitigations

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 Environmentally Constrained Portfolio

Two thermal overloads were observed under normal (N-0) operating conditions. The following facilities exhibited overloads under peak conditions, which are also listed as part of appendix C:

Bay Blvd – Miguel 230 kV line

This overload can be mitigated by the following:

- facility upgrade; or
- new Sycamore – Penasquitos 230 kV line; or
- additional generation in SDG&E (on 230 kV system North of Old Town / Mission area).

This overload is already identified in the generator interconnection process Cluster 3/Cluster 4 Phase II study results as a delivery network upgrade and is expected to be mitigated by a facility upgrade through the generator interconnection process.

Granite – Granite Tap 69 kV line section

This overload can be mitigated by generation dispatch at El Cajon 69 kV.

The ISO recommends using generation re-dispatch for mitigating this overload.

Thermal Overloads under Contingency Conditions

The following facilities were observed to be overloaded under contingency conditions. A detailed results table is included in Appendix C.

Otay Mesa – Miguel 230 kV line #1 and #2

The two lines between Otay Mesa and Miguel exhibit overloads for the loss of one of these lines under peak load conditions in the Cost Constrained and Commercial Interest portfolios. Potential mitigations for these overloads include:

- upgrade of the lines; or
- congestion management in Day-Ahead and real-time market; or
- additional generation on the 230 kV system North of Mission/Old Town area; or
- SPS to drop generation.

Non-renewable generation at Otay Mesa is responsible for these two overloads. There is no guarantee of the location and timing of the new generation in SDG&E area North of Old Town/Mission. So this potential mitigation is uncertain and cannot be relied upon. The ISO recommends using SPS to drop generation to mitigate these overloads.

TL6916 Sycamore-Scripps 69 kV line

This line exhibits an overload for the contingency of TL23042A, Miguel - Bay Boulevard 230 kV line under peak load conditions in the Commercial Interest portfolio. Potential mitigations for this overload include:

- facility upgrade; or

- new Sycamore – Penasquitos 230 kV line; or
- additional generation on the 230 kV system North of Mission/Old Town area.

The new Sycamore – Penasquitos 230 kV line would considerably reduce the loading on Sycamore – Scripps 69 kV line. Upgrading the Sycamore – Scripps 69 kV line would only solve the local issue, whereas the new Sycamore – Penasquitos 230 kV line would mitigate multiple 230 kV overloads by providing an additional path for power to flow from the southeastern part of SDG&E system to the central and northwestern part. There is no guarantee that the new generation would show up in the North of Old Town/Mission area. So this potential mitigation is uncertain and cannot be relied upon. This overload was also observed in the deliverability assessment and so generation curtailment would not be an acceptable mitigation if this generation is expected to count for resource adequacy planning purposes. As discussed later, the most cost effective feasible mitigation that would mitigate this overload with certainty would be a new Sycamore-Penasquitos 230 kV line.

Miguel 500/230 kV Bank #80 and #81

These two transformer banks exhibit an overload for the loss of one of these banks under peak load conditions in Cost Constrained, Commercial Interest and Environmentally Constrained portfolios. Potential mitigations for this overload include:

- facility upgrade/re-rate of the transformers; or
- SPS to drop generation; or
- additional Miguel 500/230 kV transformer.

These overloads were also seen at a more severe level in the deliverability assessment for the San Diego area. An SPS to drop 1,150 MW of generation is not sufficient to mitigate the identified overloads. Adding a new Sycamore-Penasquitos 230 kV line helps to reduce the loadings on the transformers and with this new line, 1,150 MW of generation tripping becomes sufficient to eliminate the transformer overloads.

Miguel 230/138 kV Bank #60

This transformer bank exhibits an overload for the contingency of Miguel 230/138 kV bank #61 in the Cost Constrained and Commercial Interest portfolios. Potential mitigations for this overload include:

- facility upgrade/re-rate of the transformers; or
- congestion management in day-ahead and real-time market; or
- SPS to drop generation.

Generation re-dispatch (curtailment of either renewable or non-renewable generation in Otay Mesa and Imperial Valley area) can mitigate this overload. The ISO recommends relying on congestion management for mitigating this overload.

Miguel – Mission 230 kV line #1 and #2

This line exhibits an overload for the contingency of Miguel Bus in Commercial Interest portfolio. Potential mitigations for this overload include:

- facility upgrade; or
- SPS to drop generation; or
- new Sycamore – Penasquitos 230 kV line; or
- additional generation on the 230 kV system North of Mission / Old Town area.

These overloads were also seen in the 'Deliverability Assessment' for San Diego area. The new Sycamore – Penasquitos 230 kV line would mitigate the overloads on Miguel – Mission 230 kV lines #1 and #2. Upgrading the lines would only solve the local issue, whereas the new Sycamore – Penasquitos 230 kV line would mitigate multiple overloads by providing an additional path for power to flow from Southeastern part of SDG&E system to the Central and Northwestern part of SDG&E system. There is no guarantee that new generation would show up in the area North of Old Town/Mission. So this potential mitigation is uncertain and cannot be relied upon. SPS to drop generation would mitigate these overloads, but the Sycamore – Penasquitos 230 kV line would mitigate multiple overloads on the system and would also limit the use of generation drop SPSs.

Old Town – Mission 230 kV line

This line exhibits an overload for the contingency of Silvergate – Old Town #1 and #2 230 kV lines in the Commercial Interest portfolio. Potential mitigations for this overload include:

- facility upgrade; or
- SPS to drop generation; or
- new Sycamore – Penasquitos 230 kV line; or
- additional generation on the 230 kV system North of Mission / Old Town area.

The new Sycamore – Penasquitos 230 kV line would considerably reduce the loading and mitigate the overload on Mission – Old Town 230 kV line. Upgrading the lines would only solve the local issue, whereas the new Sycamore – Penasquitos 230 kV line would mitigate multiple 230 kV overloads by providing additional path for power to flow from southeastern part of SDG&E system to the central and northwestern part. There is no guarantee that the new generation would show up in the North of Old Town/Mission area. So this potential mitigation is uncertain and cannot be relied upon. An SPS to drop generation would mitigate these overloads, but the Sycamore – Penasquitos 230 kV line would mitigate multiple overloads on the system and would also limit SPS use.

The new Sycamore – Penasquitos 230 kV line will mitigate the following overloads under Category A, B and C contingencies in the Commercial Interest portfolio:

- Miguel – Bay Boulevard 230 kV line;
- Miguel – Mission #1 and #2 230 kV lines;
- Mission – Old Town 230 kV line; and
- Sycamore – Scripps 69 kV line.

Some of these overloads can be mitigated by SPS to drop generation or additional future generation. However, adding more generation to the SPS can create future operational challenges and relying on potential future generation development in a specific area is not a concrete mitigation that can be counted on. The new Sycamore – Penasquitos 230 kV line will also mitigate a number of overloads observed in the deliverability study as described in section 4.4.2.

Voltage Issues

The following voltage related issues were identified with the detailed results included in appendix C.

High Voltages

Voltages above 1.05 p.u. are observed across SDG&E system under normal (N-0) conditions in the off-peak scenario (listed in appendix C) at several buses, predominantly on the 69 kV and 138 kV system. Potential mitigations for this issue include the follow:

- requiring +/- 0.95 power factor for the new generation in this area; and/or
- voltage schedule adjustments and tap adjustments across the system; and/or
- additional dynamic reactive support.

Voltage Collapse

Post transient voltage stability was tested for several contingencies. The N-1-1 contingency of Sunrise Power Link followed by Southwest Power Link resulted in voltage collapse in all four portfolios. Potential mitigations for this issue include the following:

- generation drop in Imperial Valley area and additional internal generation in San Diego area; and/or
- additional dynamic reactive support in San Diego area.

4.4.2 SDG&E Area Policy-Driven Deliverability Assessment Results and Mitigations

Base Portfolio Deliverability Assessment Results

Deliverability assessments in previous transmission planning cycles have demonstrated that the dispatch of generation at Encina was a pivotal assumption associated with certain deliverability constraints in the San Diego area. Given the uncertainty of the long-term availability of generation at Encina, this deliverability assessment for the SDG&E area was performed with the bounding assumption that all of the existing generation at Encina would be retired and not repowered. Some replacement generation, consisting of 308 MW at Otay Mesa 230 kV and 100 MW at Carlton Hills 138 kV, was modeled. Along with this generation, the following network upgrades were modeled:

- reconfigure TL23041 and TL23042 at Miguel Substation to create two Otay Mesa-Miguel 230 kV lines; and
- current limiting series reactor (3.1 ohm) on the Otay Mesa-Tijuana 230 kV line.

The results of the assessment are shown in the table below.

Table 4.4-3: Base portfolio deliverability assessment results for SDG&E area

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Borrego-Narrows 69 kV	Base Case	143%	Non CREZ-SDGE, DG-Borrego	Localized concern to be addressed through generator interconnection process
Narrows-Warners 69 kV	Base Case	117%	Non CREZ-SDGE, DG-Borrego	Localized concern to be addressed through generator interconnection process
Penasquitos-Old Town 230 kV	Base Case	101%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or upgrade line
Miguel-Bay Boulevard 230 kV	Base Case	121%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	Localized concern being addressed through generator interconnection process
Miguel-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1	107%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Bay Boulevard 230 kV	Miguel-Mission 230 kV #2	107%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 & Miguel-Mission 230 kV #2	129%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line and SPS to trip generation

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Miguel-Bay Boulevard 230 kV	Palomar-Sycamore 230 kV & Encina-San Luis Rey-Palomar 230 kV	102%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Bay Boulevard 230 kV	Palomar-Sycamore 230 kV & Artesian-Sycamore 69 kV	102%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Bay Boulevard 230 kV	Palomar-Sycamore 230 kV & Batiquitos-Shadowridge 138 kV	102%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Mission 230 kV #1	Miguel-Bay Boulevard 230 kV & Telecanyon-Grant Hill 138 kV	109%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Mission 230 kV #2	Miguel-Bay Boulevard 230 kV & Telecanyon-Grant Hill 138 kV	109%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Mission-Old Town 230 kV #1	Miguel-Bay Boulevard 230 kV	106%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Silvergate-Bay Boulevard 230 kV #1	Miguel-Mission 230 kV #1 & Miguel-Mission 230 kV #2	103%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Sweetwater-Sweetwater Tap 69 kV	Silvergate-Bay Boulevard 230 kV	118%	DG-SDGE	New Sycamore-Penasquitos 230 kV line or Upgrade line

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Escondido-San Marcos 69 kV	Encina-San Luis Rey 230 kV & Encina-San Luis Rey-Palomar 230 kV	106%	Non CREZ-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or Upgrade line
Escondido-San Marcos 69 kV	Encina-San Luis Rey-Palomar 230 kV & Encina-Penasquitos 230 kV	105%	Non CREZ-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or Upgrade line
Escondido-San Marcos 69 kV	Encina-San Luis Rey-Palomar 230 kV & Batiquitos-Shadowridge 138 kV	105%	Non CREZ-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or Upgrade line
Miguel 500/230 kV #1	Miguel 500/230 kV #2	116%	Arizona, Baja, San Diego South, Imperial-SDGE	New Sycamore-Penasquitos 230 kV line and SPS to trip generation or Third Miguel 500/230 kV transformer
Miguel 500/230 kV #2	Miguel 500/230 kV #1	115%	Arizona, Baja, San Diego South, Imperial-SDGE	New Sycamore-Penasquitos 230 kV line and SPS to trip generation or Third Miguel 500/230 kV transformer
Otay Mesa-Tijuana 230 kV	Miguel-ECO 500 kV	124%	Arizona, Baja, San Diego South, Imperial-SDGE	SPS to trip generation and CFE cross trip
Imperial Valley-ROA 230 kV	Miguel-ECO 500 kV	110%	Arizona, Baja, San Diego South, Imperial-SDGE	SPS to trip generation and CFE cross trip

Deliverability of new renewable resources in the Borrego area is limited by Category A overloads on the Borrego-Narrows 69 kV and Narrows-Warners 69 kV lines. These overloads are localized and should be mitigated through the generator interconnection process.

Deliverability of new renewable resources in the Arizona, Baja, San Diego South, Imperial-SDGE, and San Diego DG is limited by multiple Category A, B and C overloads.

- The Category A overload on Miguel-Bay Boulevard 203 kV line has been previously identified in the generator interconnection process Cluster 3/Cluster 4 Phase II study results, and is expected to be mitigated through the generator interconnection process.
- The Category A overload on Old Town-Penasquitos 230 kV line can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, the overload can be mitigated by upgrading the line.
- Category B and C overloads on Miguel-Bay Boulevard 230 kV line can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, these overloads can be mitigated by installing an SPS to trip generation. The only exception is for the Category C contingency of Miguel-Mission 230 kV #1 and #2 lines, as for this contingency both the Sycamore-Penasquitos 230 kV line and SPS to trip generation is required. Upgrades to the overloaded line as identified in the generator interconnection process would not increase the line's emergency rating and therefore would not mitigate the Category B and C overloads on the line.
- Category C overloads on Miguel-Mission 230 kV #1 and #2 lines can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, these overloads can be mitigated by installing an SPS to trip generation.
- Category B overload on Mission-Old Town 230 kV line can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, this overload can be mitigated by installing an SPS to trip generation.
- Category C overload on Silvergate-Bay Boulevard 230 kV line can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, this overload can be mitigated by installing an SPS to trip generation.

Deliverability of some of new renewable resources in the San Diego DG zone is limited by a Category B overload on the Sweetwater-Sweetwater Tap 69 kV line. The overload can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, the overload can be mitigated by upgrading the overloaded line.

Deliverability of some of new renewable resources in the San Diego DG and Non CREZ zones is limited by Category C overloads on the Escondido-San Marcos 69 kV line. These overloads can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, the overloads can be mitigated by upgrading the overloaded line.

Deliverability of renewable resources in the Arizona, Baja, San Diego South and Imperial-SDGE zones is limited by Category B overloads on the Miguel 500/230 kV #1 and #2 transformers. Tripping 1,150 MW of generation is not sufficient to eliminate the overloads. Adding a new Sycamore-Penasquitos 230 kV line helps to reduce the loads on the transformers and with the new line, tripping 1,150 MW of generation becomes sufficient to eliminate the overloads.

Alternatively, these overloads can be mitigated by adding a third Miguel 500/230 kV transformer.

Deliverability of renewable resources in the Arizona, Baja, San Diego South and Imperial-SDGE zones is limited by Category B overloads on the Otay Mesa-Tijuana 230 kV and Imperial Valley-La Rosita 230 kV lines. These overloads can be mitigated by first using an SPS to trip generation and then utilizing the CFE cross-trip, as needed.

Base Portfolio Deliverability Assessment Sensitivity Results

A sensitivity deliverability assessment was performed for the SDG&E area. This study removed the replacement generation consisting of 308 MW at Otay Mesa 230 kV and 100 MW at Carlton Hills 138 kV. However, the following associated network upgrades were still assumed to be needed and were not removed:

- reconfigure TL23041 and TL23042 at Miguel Substation to create two Otay Mesa-Miguel 230 kV lines; and
- current limiting series reactor (3.1 ohm) on the Otay Mesa-Tijuana 230 kV line.

The sensitivity study assumed that existing generation at Encina is retired, but 520 MW are repowered (260 MW at 230 kV and 260 MW at 138 kV).

The results of the sensitivity study are shown in the table below.

Table 4.4-4: Base portfolio deliverability assessment results for SDG&E area

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Borrego-Narrows 69 kV	Base Case	143%	Non CREZ-SDGE, DG-Borrego	Localized concern to be addressed through generator interconnection process
Narrows-Warners 69 kV	Base Case	117%	Non CREZ-SDGE, DG-Borrego	Localized concern to be addressed through generator interconnection process
Miguel-Bay Boulevard 230 kV	Base Case	111%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	Localized concern being addressed through generator interconnection process

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Miguel-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 & Miguel-Mission 230 kV #2	118%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Mission 230 kV #1	Miguel-Bay Boulevard 230 kV & Telecanyon-Grant Hill 138 kV	100%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Miguel-Mission 230 kV #2	Miguel-Bay Boulevard 230 kV & Telecanyon-Grant Hill 138 kV	100%	Arizona, Baja, San Diego South, Imperial-SDGE, DG-SDGE	New Sycamore-Penasquitos 230 kV line or SPS to trip generation
Sweetwater-Sweetwater Tap 69 kV	Silvergate-Bay Boulevard 230 kV	111%	DG-SDGE	Upgrade line or New Sycamore Penasquitos 230 kV line
Escondido-San Marcos 69 kV	Encina-San Luis Rey 230 kV & Encina-San Luis Rey-Palomar 230 kV	100%	Non CREZ-SDGE, DG-SDGE	Upgrade line Or New Sycamore-Penasquitos 230 kV line
Miguel 500/230 kV #1	Miguel 500/230 kV #2	118%	Arizona, Baja, San Diego South, Imperial-SDGE	Third Miguel 500/230 kV transformer
Miguel 500/230 kV #2	Miguel 500/230 kV #1	115%	Arizona, Baja, San Diego South, Imperial-SDGE	Third Miguel 500/230 kV transformer
Otay Mesa-Tijuana 230 kV	Miguel-ECO 500 kV	126%	Arizona, Baja, San Diego South, Imperial-SDGE	SPS to trip generation and CFE cross trip

Overloaded Facility	Contingency	Flow	Undeliverable Renewable Zone	Mitigation
Imperial Valley-ROA 230 kV	Miguel-ECO 500 kV	112%	Arizona, Baja, San Diego South, Imperial-SDGE	SPS to trip generation and CFE cross trip

The Borrego area overloads are not affected by the sensitivity study assumptions. The Category A overloads on Borrego-Narrows 69 kV and Narrows-Warners 69 kV lines are still observed and should be mitigated through the generator interconnection process.

Many of the overloads affecting the deliverability of new renewable resources in the Arizona, Baja, San Diego South, Imperial-SDGE, and San Diego DG are either eliminated or reduced using the sensitivity study assumptions. The remaining overloads and their proposed mitigation are listed below.

- The Category A overload on Miguel-Bay Boulevard 203 kV line has been previously identified in the C3C4 Phase II study, and is expected to be mitigated through the generator interconnection process.
- The Category C overload on Miguel-Bay Boulevard 230 kV line can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, this overload can be mitigated by installing an SPS to trip generation. Upgrades to the overloaded line as identified in the generator interconnection process would not increase the line's emergency rating and therefore would not mitigate the Category B and C overloads.
- Category C overloads on Miguel-Mission 230 kV #1 and #2 lines can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, these overloads can be mitigated by installing an SPS to trip generation.

Deliverability of some of the new renewable resources in the San Diego DG zone is still limited by a Category B overload on the Sweetwater-Sweetwater Tap 69 kV line. The overload can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, the overload can be mitigated by upgrading the line.

Deliverability of some of new renewable resources in the San Diego DG and Non-CREZ zones is still limited by a Category C overload on Escondido-San Marcos 69 kV line. The overload can be mitigated by adding a new Sycamore-Penasquitos 230 kV line. Alternatively, the overload can be mitigated by upgrading the line.

Deliverability of renewable resources in the Arizona, Baja, San Diego South and Imperial-SDGE zones is still limited by Category B overloads on the Miguel 500/230 kV #1 and #2 transformers. These overloads can be mitigated by adding a third Miguel 500/230 kV transformer. Using an SPS to trip generation is not sufficient to eliminate the overloads. Adding a new Sycamore-Penasquitos 230 kV line helps to reduce the loads on the transformers, and with the new line, tripping 1,150 MW of generation becomes sufficient to eliminate the overloads.

Deliverability of renewable resources in the Arizona, Baja, San Diego South and Imperial-SDGE zones is still limited by Category B overloads on the Otay Mesa-Tijuana 230 kV and Imperial Valley-La Rosita 230 kV lines. These overloads can be mitigated by first using an SPS to trip generation and then utilizing the CFE cross-trip, as needed.

Analysis of Other Portfolios

The need for transmission upgrades identified above is analyzed for other renewable portfolios by comparing the generation behind the deliverability constraint. The results are shown in Table 4.4-5: Portfolios Requiring the Transmission Upgrade. The generation capacity listed for each renewable zone represents only the generators contributing to the deliverability constraint and may be lower than the total capacity in the renewable zone.

Table 4.4-5: Portfolios Requiring the Transmission Upgrade

Transmission Upgrade	Renewable Zones	Comm Interest (MW)	High DG (MW)	Env. Const. (MW)	Cost Const. (MW)	Needed for Portfolios
Sycamore-Penasquitos 230 kV line	Arizona	290	290	290	290	Commercial Interest Env. Constrained
	Baja	100	0	0	0	
	San Diego South	384	0	384	384	
	Imperial-SDGE	921	220	921	220	
	DG-SDGE	130	130	130	130	

Recommendation

The deliverability assessment resulted in a number of overloads which can be mitigated by the new Sycamore – Penasquitos 230 kV line. The following overloads observed in the Commercial Interest portfolio and Environmental Constrained portfolio can be mitigated by this new line:

- Old Town – Penasquitos 230 kV line;
- Miguel – Mission #1 and #2 230 kV lines;
- Mission – Old Town 230 kV line;
- Silvergate – Bay Boulevard 230 kV line;
- Sweetwater – Sweetwater Tap 69 kV line;
- Escondido – San Marcos 69 kV line; and
- Miguel 500/230 kV #1 and #2 transformers (SPS to trip generation needed in addition to proposed upgrade).

As described in Table 4.4-4, an SPS to drop generation for some of these overloads is not adequate. Some of these overloads are also observed as part of the powerflow and stability study as described in section 4.3.1. As discussed below, considering the need to mitigate multiple overloads in the base portfolio and at least one other portfolio, the new Sycamore – Penasquitos 230 kV line is the recommended alternative.

Transmission Plan Deliverability with Recommended Transmission Upgrades

An estimate of the deliverability for the previously identified SDG&E area deliverability constraint is listed in Table 4.4-6: TP Deliverability for Area Deliverability Constraints in SDG&E Area. This area constraint is not binding on the generation amounts in the four portfolios studied.

Table 4.4-6: TP Deliverability for Area Deliverability Constraints in SDG&E Area

Area Deliverability Constraint	Renewable Zones	TP Deliverability (MW)
WECC Path 43 flow limit	Arizona Baja San Diego South Imperial-SDGE DG-SDGE Non CREZ-SDGE	2,400 - 3,200

4.4.3 SDG&E Area Policy-Driven Conclusions

As part of the policy-driven study in the SDG&E area, three types of studies were carried out to examine the need for upgrades, the powerflow, stability and deliverability assessments. These three studies point to certain common needs that can be addressed by a single upgrade. The new Sycamore – Penasquitos 230 kV line will mitigate the following overloads observed in the Commercial Interest and Environmental Constrained portfolios:

- Old Town – Penasquitos 230 kV line;
- Miguel – Mission #1 and #2 230 kV lines;
- Mission – Old Town 230 kV line;
- Silvergate – Bay Boulevard 230 kV line;
- Sweetwater – Sweetwater Tap 69 kV line;
- Escondido – San Marcos 69 kV line;
- Miguel 500/230 kV #1 and #2 transformers (SPS to trip generation needed in addition to proposed upgrade);
- Sycamore – Scripps 69 kV line.

Some of these overloads can be mitigated by upgrading the individual elements or by adding generation to SPS, which will result in instantaneous generation drop. Individual upgrades will only mitigate the local problems and adding more generation to an SPS can create future operational challenges. In addition, the combined cost of the individual upgrades is less than but significant compared to the alternative of building the Sycamore-Penasquitos 230 kV line. With the proposed Sycamore – Penasquitos 230kV line modeled in the base cases under 2022 peak conditions, the line was utilized beyond 95% of its normal rating, which in turn facilitated higher utilization of Sunrise Power Link. This analysis provides additional evidence that the line would relieve excessive loading on the Southwest Power Link, the 500/230 kV transformers at Miguel, the 230 kV system from Miguel to Mission and the underlying 138 kV and 69kV system.

Considering the wide-spread impact, in at least two of the renewable portfolio cases of the new Sycamore – Penasquitos 230 kV line, and the identified need for this line during potential long-term outages of SONGS, the ISO is recommending approval of the development of this line.

For Miguel 230/138 kV bank overload, the ISO recommends relying on generation re-dispatch.

For high voltage issues observed in the off-peak scenario, the ISO recommends relying on the following mitigations:

- requiring +/- 0.95 power factor for the new generation in this area; and/or
- voltage schedule adjustments and tap adjustments across the system; and/or
- additional dynamic reactive support.

A voltage instability issue observed for the N-1-1 contingency of the Sunrise Power Link and Southwest Power Link can be mitigated by ensuring generation drop at the Imperial Valley substation and additional internal generation in the San Diego area. Additional dynamic reactive support would also help prevent the voltage collapse. The nuclear back-up study evaluated the need for additional dynamic reactive support in San Diego area. Please refer to section 3.5 for a detailed write-up on the nuclear back-up studies.

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 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 policy assessment for SDG&E area has identified that a new Sycamore-Penasquitos 230 kV line is an alternative that

meets policy-driven transmission needs in the Commercial Interest and Environmental Constrained portfolios. In addition this line has been identified as needed in the mid-term nuclear backup alternative mitigation plans documented in Chapter 3. The cost of the Sycamore-Penasquitos 230 kV line as a Category 1 element is expected to be higher than the numerous reconductoring and SPS projects that would also meet the identified needs. However, Sycamore-Penasquitos is also needed in both of the alternative mitigation plans for mitigating a long-term outage of SONGS. The ISO recommends approval of this project in this

2012-2013 transmission planning cycle to ensure delivery of generation needed to meet the 33 percent RPS.

4.5 Sensitivity study for high out of state import of renewable

A sensitivity study of modeling high out of state imports of renewable energy was conducted in 2012-2013 planning cycle. The sensitivity study used the Commercial Interest portfolio as the base case. It was assumed that 3,000 MW of renewable generation importing into California at El Dorado 500 kV bus from other states. Meanwhile, 3,000 MW of renewable generation was removed from the Commercial Interest portfolio starting from the bottom of the portfolio's supply curve that was presented in the stakeholder meeting on April 2, 2012.

This sensitivity study focused on examining effects on the high voltage (500 kV) system within California and the results are for informational purposes only. The assessment was conducted on the peak load scenario. The starting base case was the peak load base case for the Commercial Interest portfolio. After adding 3,000 MW renewable generation production at the El Dorado 500 kV bus, the path flows were adjusted to be within path ratings. The major path flows in the sensitivity base case are listed in Table 4.5-1. A summary of the simulation findings are shown in Table 4.5-2.

Table 4.5-1: Path flows in the high out of state import sensitivity case (MW)

Path	Flow
West of River	10950
East of River	4187
COI	4800
PDCI	3100
Path 26	-796

Table 4.5-2: Simulation results in high out of state import sensitivity case

Contingencies	Violations	Notes
El Dorado – Lugo and Mohave – Lugo 500 kV line N-2 outage	Victorville – Lugo 500 kV line overload	130% of emergency rating
El Dorado – Lugo and Mohave – Lugo 500 kV line N-2 outage	El Dorado – McCullough 500 kV line overload	139% of emergency rating
El Dorado – Lugo and El Dorado – Mohave 500 kV line N-2 outage	Victorville – Lugo 500 kV line overload	131% of emergency rating
El Dorado – Lugo and El Dorado – Mohave 500 kV line N-2 outage	El Dorado – McCullough 500 kV line overload	140% of emergency rating
Red Bluff – Devers 500 kV #1 and #2 lines N-2 outage	Victorville – Lugo 500 kV line overload	107% of emergency rating
Colorado River – Red Bluff 500 kV #1 and #2 lines N-2 outage	Victorville – Lugo 500 kV line overload	100% of emergency rating
Loss of 3000 MW at El Dorado simultaneously	Case diverged	Mainly caused by voltage instability in NW

To mitigate the issues identified in the study, the following potential mitigations were considered. As this sensitivity analysis was conducted for information purposes only, the ISO is not recommending approval of the major upgrades listed below, in this transmission plan, as noted below.

Transmission Overloads:

Option 1

With the assumption that all additional out of state renewable generation would be injected at El Dorado 500 kV bus, expanding the transmission system from El Dorado to the load centers was found to be needed. The following upgrades were considered in the sensitivity study to mitigate the violations listed in Table 4.5-2.

- Table 4.5-2build a new 500 kV line from El Dorado to Rancho Vista (not recommended for approval in this transmission plan);
- switch-in the second series caps on El Dorado – Lugo and Mohave – Lugo 500 kV lines and upgrade the series cap and line rating to 3800/4000 amps (normal/emergency); and
- relocate El Dorado – Lugo 500 kV line to eliminate El Dorado – Lugo and El Dorado – Mohave as a common mode Category C contingency.

Option 2

Upgrades on other branches of the North branch group of West of River could also help mitigate the identified violations. For example, converting the Mead-Adelanto 500 kV AC line to DC line with associated upgrades downstream of Adelanto could potentially mitigate the overloads identified on the Victorville to Lugo 500 kV line. The ISO is not recommending approval of this option in this transmission plan.

Pacific Northwest Voltage Instability

The potential voltage instability was mainly caused by voltage problems in Northwest areas. The same voltage instability issue was also identified in generator interconnection process Cluster 4 Phase 1 study, and as well as in WECC project review groups. The ISO is participating in WECC project review groups to ensure an acceptable resolution of this issue is reached.

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Chapter 5

5 Economic Planning Study

5.1 Introduction

The economic planning study simulates power system operations over extended period in the planning horizon and identifies potential congestion in the ISO controlled grid. The study objective is to find economically-driven network upgrades to increase production efficiency and reduce ratepayers' costs.

The economic planning study is accomplished by simulating system operations based on the unified planning assumptions. The study was performed after completing reliability-driven and policy-driven transmission studies. Network upgrades identified as needed for grid reliability and renewable integration were taken as inputs and modeled in the economic planning database. In this way, the economic planning study started from a "feasible" system that meets reliability standards and policy needs. Then, the economic planning study sought for additional network upgrades that are cost-effective to mitigate grid congestion and increase production efficiency.

The studies used production simulation as the primary tool to identify grid congestion and assess economic benefits of congestion mitigation measures. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. For each study year, the simulation is conducted for 8,760 hours, which are total number of hours in a year. The potential economic benefits are quantified as reduction of ratepayer's costs based on the ISO Transmission Economic Analysis Methodology (TEAM)[23].

5.2 Study Steps

The economic planning study is conducted in two consecutive steps as shown in Figure 5.2-1.

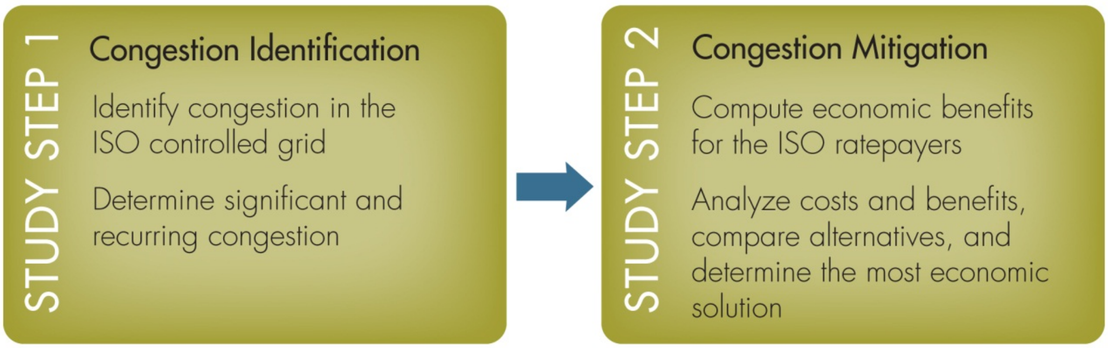
In the first study step (i.e. congestion identification), a production simulation is conducted for each hour of the study year. Identified congestion is tabulated and ranked by severity, which is expressed as congestion costs in US dollars and congestion duration in hours. Based on the simulation results, five high-priority studies are determined.

In the second study step (i.e. congestion mitigation), in the high-priority studies, congestion mitigation plans are evaluated for each of the high-priority studies. Using the production simulation and other means, the ISO quantified economic benefits for each proposed network upgrade alternatives. Finally, a cost-benefit analysis is conducted to determine if the proposed network upgrades are economic. In comparison of multiple alternatives that would address identified congestion issues, net benefits are compared with each other, where the net benefits

[23] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, June 2004, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

are calculated as the gross benefits minus the costs. The most economical solution is the alternative that has the largest net benefit.

Figure 5.2-1: Economic planning study – two steps



5.3 Technical Approach

Economic benefits of network upgrades are evaluated using production simulation. Traditional power flow analysis is also used where needed. Generally, production simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis plays a supporting role in quantifying other economic benefits such as capacity savings.

A major component of the economic benefits is production benefit, which is the ratepayers' cost savings. The production benefit is quantified by production simulation that 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 accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the "pre-project" and "post-project" study results, production benefits can be calculated from savings of production costs or ratepayer payments. The production benefit includes three components: consumer payment decrease, generation revenue increase and transmission congestion revenue increase. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and the TEAM principles.

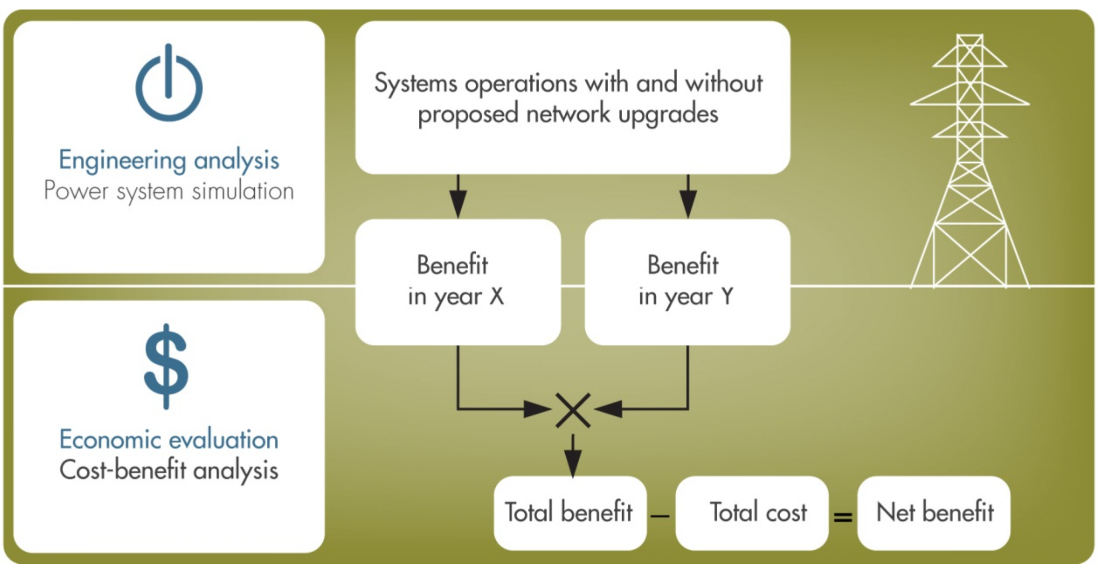
In addition to the production benefits, capacity benefit is also an important component of the total economic benefit. Types of capacity benefits include system RA savings and local RA savings. The system RA benefit corresponds to a situation where a network upgrade for importing transmission facility leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where an upgraded transmission facility that leads to a reduction of local capacity requirement in a load area.

In addition to the production and capacity benefits, any other benefits — where applicable and quantifiable — can also be included. However, it is not always easy to quantify social and political types of benefits into dollars.

Once the total economic benefit is calculated, the benefit is weighed against the cost. In order to justify a proposed network upgrade, the required criterion is that the ISO ratepayer benefit needs to be greater than the cost of the network upgrade. If the justification is successful, the proposed network upgrade may qualify as an economically-driven project.

The technical approach of economic planning study is depicted in Figure 5.3-1. The economic planning study starts from engineering analysis with power system simulations (using production simulation and snapshot power flow analysis). The engineering analysis phase is the most time consuming part of the study. Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis. The cost-benefit analysis is a financial and accounting calculation that is normally conducted in spreadsheets.

Figure 5.3-1: Technical approach of economic planning study



5.4 Tools and Database

The ISO used the software tools listed in Table 5.4-1 for this economic planning study.

Table 5.4-1: Tools used for this economic planning study

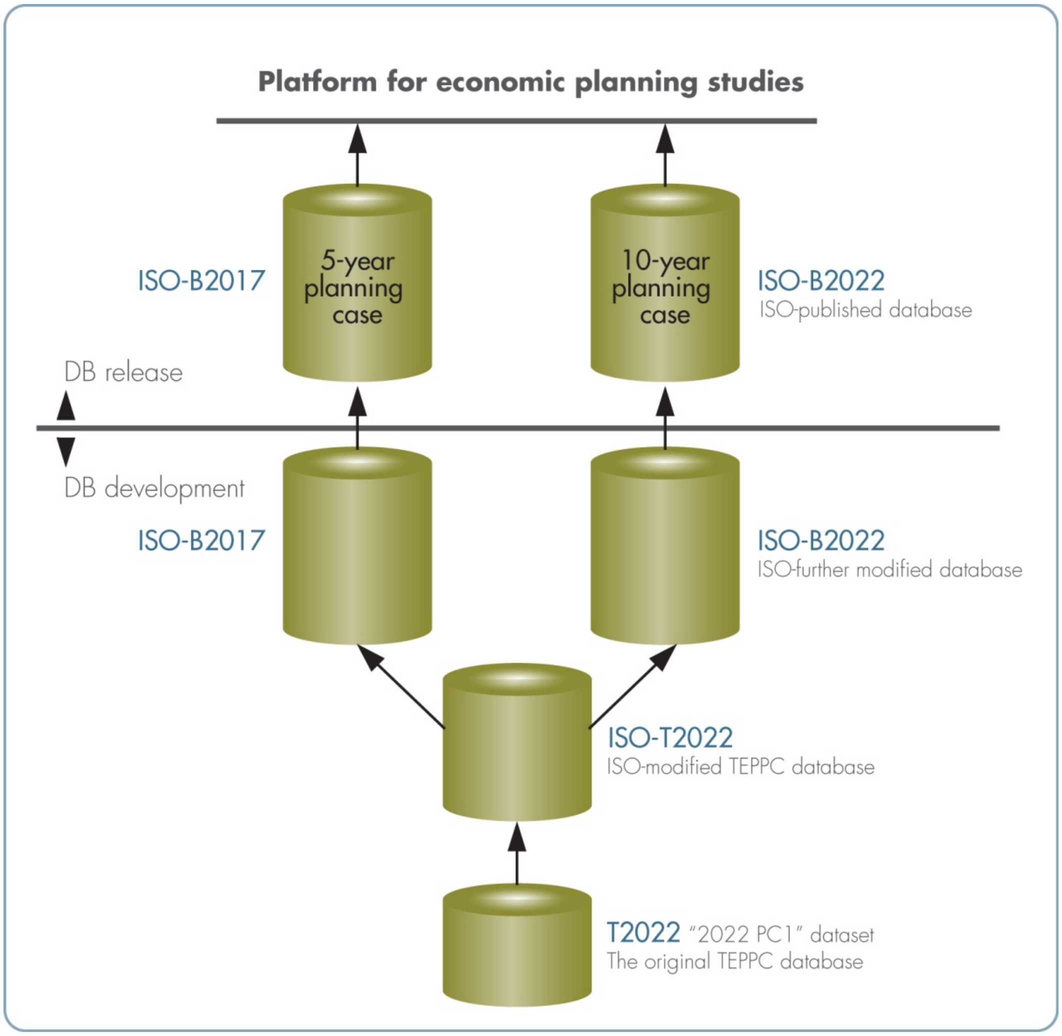
Program name	**Version**	**Date**	**Functionality**
ABB GridView™	8.3c1.1	28-Nov-2012	The software program is a production simulation tool with DC power flow to simulate system operations in a continuous time period, e.g. 8,760 hours in a study year
GE PSLF™	18.0_01	24-Oct-2011	The software program is an AC power flow tool to compute line loadings and bus voltages for selected snapshots of system conditions, e.g. summer peak or spring off-peak

This study used the WECC production simulation model as a starting database. The database is often called the Transmission Expansion Planning Policy Committee (TEPPC) dataset. For this study, the ISO used the "2022 PC1" dataset released on May 2, 2012.

Based on the TEPPC "2022 PC1" datasets, the ISO developed the 2017 and 2022 base cases for the production simulation. In creation of the 5th-year (2017) and 10th-year (2022) base cases, the ISO applied numerous updates and additions with the intention of modeling the California power system in more detail. Those modeling updates and additions are described in Section 5.5 (Study Assumptions).

Figure 5.4-1 shows the process of developing the ISO base cases.

Figure 5.4-1: Database setup



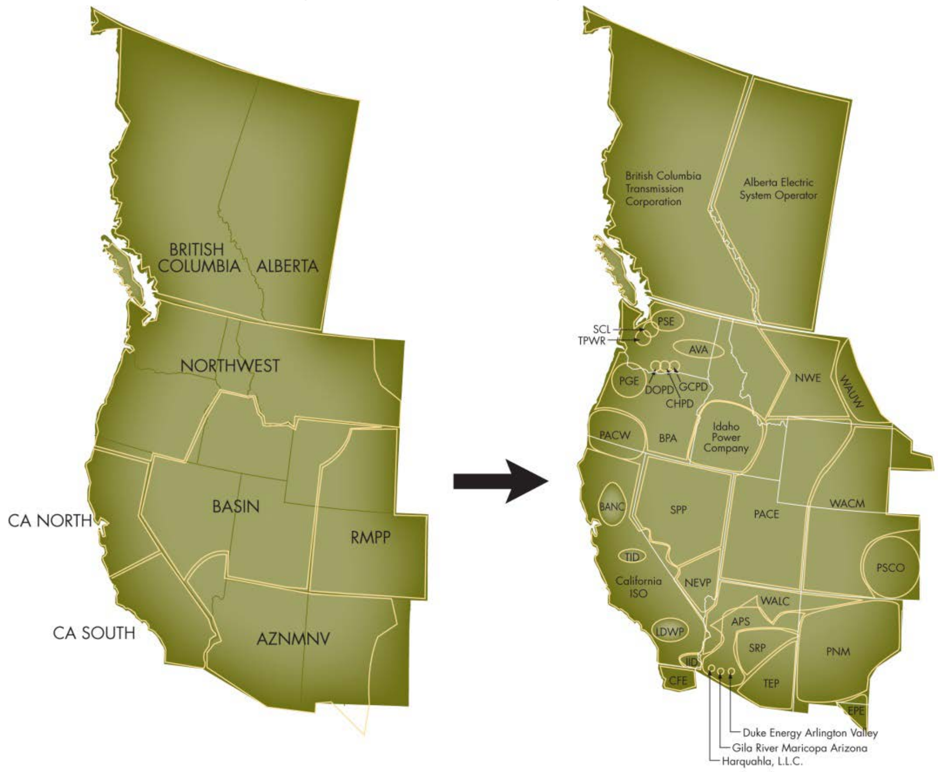
5.5 Study Assumptions

This section summarizes major assumptions used in the economic planning study. The section also highlights the ISO enhancements and modifications to the TEPPC database.

5.5.1 System Modeling

In system modeling, the ISO made major topology changes to the TEPPC database and modeled Balancing Authority Areas (BAAs) i.e. control areas in the WECC system. Figure 5.5-1 shows the change in modeling control areas.

Figure 5.5-1: Modeling control areas



The TEPPC database represented eight geographic regions that did not quite function as BAAs. The ISO changed the eight geographic regions to 31 BAAs. The WECC system has 37 BAAs. The ISO embedded five small BAAs (HGBA, GRMA, AVBA, GRBA and GWA) in the surrounding bigger BAAs. Also, the ISO merged the two Nevada utility areas (SPPC and NEVP) into one BAA representing Nevada Energy (NVE)[24].

[24] The Nevada utility area (SPPC and NEVP) will be combined into one control area under Nevada Energy (NVE) when the One Nevada Line (ON-Line) goes into service. The ON-Line is currently under construction and expected to be operational in 2013.

Specifically, with the California power system, the TEPPC database defined only two geographic regions: “CALIF_NORTH” and “CALIF_SOUTH”. However, the ISO changed them into five BAAs represented by:

- California ISO (CISO)
- Balancing Authority Northern California (BANC)
- Turlock Irrigation District (TID)
- Los Angles Department Water and Power (LADWP)
- Imperial Valley Irrigation District (IID)

With the change of eight geographic regions into 31 BAAs, the ISO changed 13 hurdle rates interfaces from the original TEPPC dataset to 60 hurdle rates interfaces in the ISO database. The hurdle rates represent barriers and frictions between different BAAs, such that the economic dispatch is less optimal than a perfect dispatch of the total system.

Finally, on top of the BAAs, five reserve sharing groups were overlaid. The reserve sharing groups are the greater BPA area, Pacific Northwest and Basin, Rocky Mountain, Desert Southwest and Balancing Authority of Northern California (BANC).

The system modeling is consistent with the framework of WECC Phase 2 EIM study[25]. The ISO made some improvements, like combing northern and southern Nevada areas into a single BAA.

5.5.2 Load demand

As a norm for economic planning studies, production simulation models 1-in-2 heat wave load in the system to represent typical or average load conditions. In the ISO developed base cases, load modeling used data from the following sources.

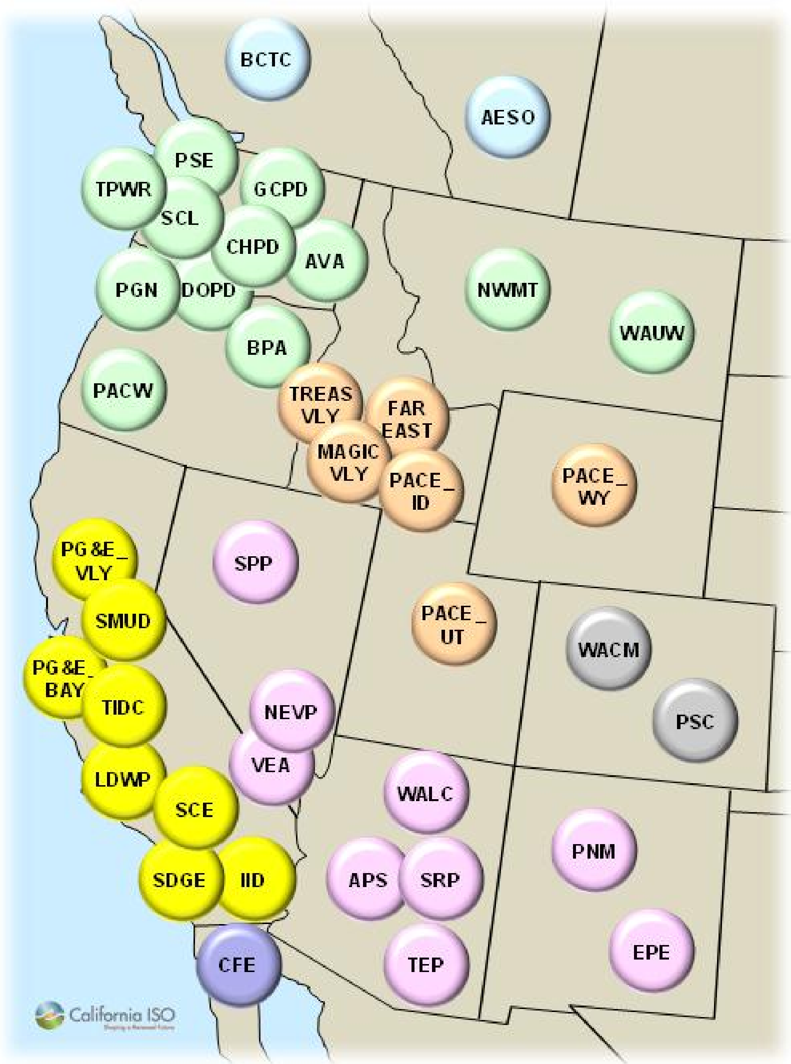
- In modeling California load, the study used the CEC demand forecast. In the TEPPC database, the California load model were based on CEC 2012 demand forecast dated Feb 2012. The ISO replaced that load model with the latest CEC demand forecast data published in September 2012.
- In modeling load for other areas in the WECC system, the study used 2012 forecast data from the WECC Load and Resource Subcommittee (LRS), which comes from different utilities in the WECC. In the TEPPC database, the load model was based on LRS 2011 data. The ISO replaced that load model with the latest LRS 2012 data.

In the WECC production simulation model, 39 load areas were represented. In the ISO developed base cases, one more load area was added and the total number of load areas increased to 40. VEA (Valley Electric Association), which joined the ISO-controlled grid on January 10, 2013. The VEA area was original a part of NEVP load area. In the new model, the

[25] WECC report: “WECC EDT Phase 2 EIM Benefits Analysis & Results (October 2011 Revision)”, report prepared for Western Electricity Coordinating Council on October 11, 2011 by Energy Environmental Economics, Inc.

ISO created this new area and included it in the CAISO BAA. Figure 5.5-2 shows the 40 WECC load areas represented in the ISO-modified database.

Figure 5.5-2 Load areas represented in the WECC production simulation model



In the production simulation model, each load area has an hourly load profile for the 8,760 hours. Individual bus load is calculated from the area load using a load distribution pattern that was imported from a power flow base case. In the original TEPPC database, only one summer load distribution pattern was modeled. The ISO enhanced the load distribution model by adding three more load distribution patterns of spring, autumn and winter. Thus, in the developed ISO base cases have four load distribution patterns for different seasons.

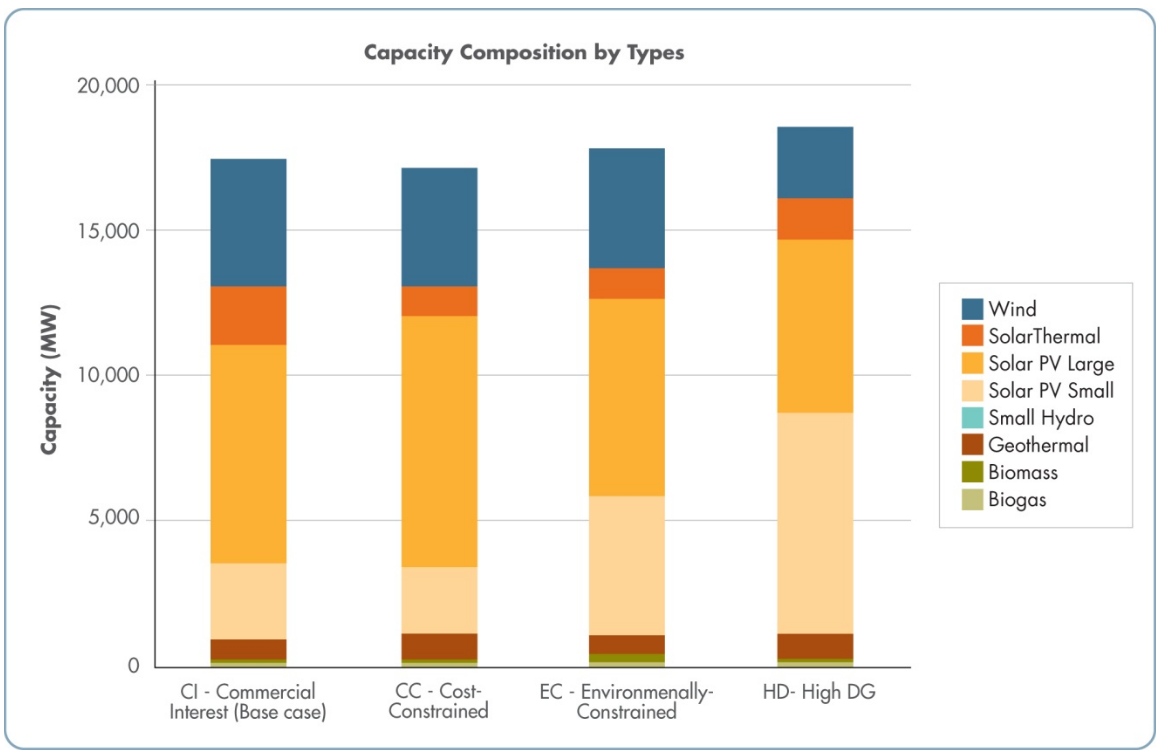
5.5.3 Generation resources

For renewables, the original TEPPC dataset modeled the “Modified Cost-Constrained case” for the California 33% RPS based on 2011 CPUC portfolios. The ISO removed that old RPS model and replaced it with the new 2012 CPUC/CEC portfolios. With the new CA 33% RPS data, the study modeled four alternative RPS net short portfolios as listed in Table 5.5-1, while Figure 5.5-3 shows their capacity composition. For more details of the renewable portfolios, please see descriptions in Chapter 4.

Table 5.5-1: Renewable net-short portfolios

Acronym	Renewable Portfolios	Study Case
CI	Commercial Interest portfolio	Base case
CC	Cost-constrained portfolio	Sensitivity case
EC	Environmentally constrained portfolio	Sensitivity case
HD	High distributed generation portfolio	Sensitivity case

Figure 5.5-3 Composition of the 33 percent RPS net short portfolios



For thermal generation, there are no major discrepancies between the TEPPC database and the ISO model. In other words, the TEPPC database has covered all the known and credible thermal resources in the planning horizon.

5.5.4 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.

The original TEPPC database did not enforce transmission limits for 500 kV transformers 230 kV lines. For this study, the ISO enforced those transformer limits throughout the system and enforced the 230 kV line limits in California. Such modifications were to make sure that transmission line flows stayed within their rated limits.

Another important enhancement is the addition of transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled “what-if” contingencies on the 500 kV and 230 kV voltage levels in the California transmission grid. This makes sure that in the event of a losing one (and sometimes multiple) transmission facility, the remaining transmission facilities would stay within their emergency limits.

Economic planning studies start from a feasible system that meets reliability standards and policy requirements. To establish a feasible system, needed reliability-driven and policy-driven network upgrades are modeled in the base case. The ISO selected some major network upgrades and modeled them into the base case. Those selected network upgrades were usually above 115 kV level and deemed to have impacts on the power flows in the bulk transmission system. Network upgrades on 115 kV and lower voltage levels were assumed to be related local problems and have no significant impact on the bulk transmission system.

In the TEPPC database, some of approved network upgrades were not included. The ISO rectified the database by adding those missing network upgrades. The added network upgrades are listed in Table 5.5-2 through Table 5.5-6.

Table 5.5-2: Reliability-driven network upgrades added to the database model[26]

#	Project approved or conceptual	Utility	ISO-approval	Operation year
1	Occidental of Elk Hills 230 kV interconnection	PG&E	TP2008-2009	2010
2	Morro Bay 230/115 kV transformer #7	PG&E	TP2009-2010	2009
3	Fresno interim reliability project (reconductoring 230 kV lines)	PG&E	TP2009-2010	2014
4	Ashlan – Gregg and Ashlan – Herndon 230 kV line reconductor	PG&E	TP2010-2011	2015
5	Gill Ranch gas storage interconnection	PG&E	TP2010-2011	2011
6	Moraga – Castro Valley 230 kV capacity upgrade	PG&E	TP2010-2011	2013
7	Midway – Kern PP 230 kV lines 1-3 & 4 capacity increase	PG&E	TP2010-2011	2013
8	Fulton 230/115 kV transformer project	PG&E	TP2010-2011	2014
9	Rio Oso – Atlantic 230 kV line #2	PG&E	TP2010-2011	2015
10	Red Bluff 230 kV Substation	PG&E	TP2010-2011	2016
11	Morro Bay – Mesa 230kV line	PG&E	TP2010-2011	2017
12	Tulucay 230/60 kV transformer #1 replacement	PG&E	TP2011-2012	2014
13	Borden voltage support	PG&E	TP2011-2012	2019
14	Del Amo – Ellis loop-in	SCE	TP2011-2012	2013

[26] The "Reliability-driven network upgrade" table lists major network upgrades of 230 kV and above. In fact, the ISO modeling additions also included network upgrades of lower voltage levels. For brevity, minor and lower voltage upgrades are not listed here. For details of the listed network upgrades, please refer to relevant ISO Transmission Plan reports.

15	Barre – Ellis 230kV reconfiguration	SCE	TP2012-2013	2014
16	Northern Fresno 115 kV area reinforcement	PG&E	TP2012-2013	2018
17	Series reactor on Warnerville – Wilson 230 kV line	PG&E	TP2012-2013	2017
18	Gates 500/230 kV transformer #2	PG&E	TP2012-2013	2017
19	Gates – Gregg 230 kV line	PG&E	TP2012-2013	2022
20	Contra Costa Substation 230 kV switch replacement	PG&E	TP2012-2013	2015
21	Arco 230/70 kV transformer #2	PG&E	TP2012-2013	2013
22	Gregg – Herndon No.2 230 kV line circuit breaker upgrade	PG&E	TP2012-2013	2015
23	Kearney 230/70 kV transformer addition	PG&E	TP2012-2013	2015

Table 5.5-3: Policy-driven network upgrades added to the database model

#	Project approved or conceptual	Utility	ISO approval	Operation year
1	IID-SCE Path 42 upgrade	SCE	TP2010-2011	2013
2	Warnerville – Belotta 230 kV line reconductoring	PG&E	TP2012-2013	2017
3	Lugo – Eldorado series capacitors and terminal equipment upgrade	SCE	TP2012-2013	2020
4	Sycamore – Penasquitos 230 kV line	SDG&E	TP2012-2013	2020

Table 5.5-4: GIP-related network upgrades added to the database model

#	Project approved or conceptual	Utility	Note	Operation year
1	South of Contra Costa reconductoring	PG&E	ISO LGIA	2012
2	West of Devers 230 kV series reactors	SCE	ISO LGIA	2013 (Till 2019)
3	West of Devers 230 kV reconductoring	SCE	ISO LGIA	2019

Table 5.5-5: Other network upgrades added to the database model

#	Project approved or conceptual	Utility	Note	Operation year
1	PDCI Upgrade Project	BPA	Under construction	2015
2	Barren Ridge Renewable Transmission Project	LADWP	DWP-approved	2017
3	Scattergood – Olympic transmission line	LADWP	DWP-approved	2015
4	Cottle 230 kV ring bus, load relocation and removal of tie to Bellota – Warnerville	PG&E	PG&E maintenance project	2012
5	Merchant 230 kV reconfiguration project	SCE	ISO approved	2012
6	Bob Tap 230 kV switchyard and Bob Tap – Eldorado 230 kV line	VEA	ISO approved	2015

Table 5.5-6: Assumed network upgrades added to the database model[27]

#	Project approved or conceptual	Utility	Reason	Operation year
1	Cool Water – Lugo 230 kV line[28]	SCE	Renewable delivery	2018
2	Add solar G-1 to Los Banos 500 kV RAS scheme	PG&E	Renewable delivery	2018
3	Open loop operation for Kingsburg – Corcoran 115 kV transmission path (This is an operational measure)	PG&E	Renewable delivery	2017
4	Upgrade Inyo 115 kV phase shifter	SCE	Renewable delivery	2017
5	Relocate 47 MW of solar PV from PG&E south Fresno area to SCE Big Creek area near Rector substation in the Environmentally-Constrained (EC) RPS portfolio[29]	PG&E, SCE	Renewable delivery	2017

5.5.5 Accounting Parameters Used in Cost-Benefit Analysis

For each subject of the economic planning study, a cost-benefit analysis was made, where the total costs were weighted against the total benefits of the proposed network upgrades. In this context, the "total cost" and "total benefit" are defined as follows:

[27] In the "Assumed network upgrades" table, the listed network upgrades are needed to establish a feasible database to meet reliability standards and policy needs. These assumptions are for database modeling purpose and do not imply that the network upgrades will be approved and constructed.

[28] Either the Cool Water – Lugo 230 kV line or equivalent transmission upgrade are needed to deliver the renewables in the Coolwater-Kramer area. Another alternative is the proposed AV Clearview Transmission. As a placeholder, the Cool Water – Lugo 230 kV line is used in the database modeling, as this proposed line has a lower cost than other known alternatives. It must be noted such a modeling assumption does not suggest any of the alternatives are preferred; nor does the assumption imply any of the proposed network upgrades will be approved.

[29] The relocation of 47 MW of solar PV resources is needed for renewable energy delivery. Without the RPS resource relocation, the solar PV energy would have curtailment because of transmission limitations. This resource relocation is only applicable for the Environmentally-Constrained (EC) portfolios but is not necessary for the other RPS portfolios.

- Total cost is the total revenue requirement in net present value at the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs. As a rough estimate, the utility's revenue requirement is estimated as the capital cost multiplied by a factor of 1.45, which represents a high-end cost estimate. Actual revenue requirement varies based on specific financial assumptions of utilities or other entities.
- Total benefit means the accumulated yearly benefits over the economic life of the proposed network upgrade. The yearly benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated to the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years[30].

In this economic planning study, engineering analysis determined the yearly benefits through production simulation and power flow analysis. Production simulation was conducted for the 5th planning year and the 10th planning year. Therefore, year 2017 and 2022 benefits were calculated. For the intermediate years between 2017 and 2022, the benefits were estimated by linear interpolation. For years beyond 2022, the benefits were estimated by extending the 2022 year benefit with an assumed escalation rate.

In calculation of yearly benefits into total benefit, the following accounting parameters were used:

- economic life of new transmission facilities = 50 years;
- economic life of upgraded transmission facilities = 40 years;
- economic life of increased capacity values = 30 years;
- benefits escalation rate beyond year 2022 = 1 percent (real);
- benefits discount rate = 7 percent (real);
- rate of system RA benefit = $5/kW-year[31]; and
- rate of LCR benefit = $20/kW-year[32]

In this economic planning study, all costs and benefits are expressed in US dollars in 2012 values. The costs and benefits are in net present values, which are discounted to the proposed operation year of the studied network upgrade. By default, the proposed operation year is 2017 unless specially indicated.

[30] Discount of yearly benefit into the present worth is calculated by $b_i = B_i / (1 + d)^i$, where b_i and B_i are the present and future worth respectively; d is the discount rate; and i is the number of years into the future. For example, given a yearly economic benefit of $10M, if the benefit is in the 30th year, its present worth is $1.3M based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7M or $0.3M respectively. In essence, going into future years, the present worth of a yearly economic benefit becomes very small.

[31] The rate of system RA benefit is the assumed price difference between California and out-of-state.

[32] The rate of LCR benefit is the assumed price difference between LCR and system RA.

5.6 Congestion Identification and Scope of High Priority Studies

Congestion identification is the first step in the economic planning study. Grid congestions were identified by production simulation of 8,760 hours in each study year, where the study years were 2017 and 2022.

This section describes congestion simulation results and scoping of high priority studies.

Table 5.6-1 lists identified potential congestion, where congestion issues are grouped into 12 areas. The listed congestion is ranked by severity, which is identified by average congestion costs in the rightmost column.

Table 5.6-1: Simulated congestion in the ISO-controlled grid

#	Area	Utility	Year 2017		Year 2022		Average Congestion Cost ($M)
			Duration (hours)	Cost ($M)	Duration (hours)	Cost ($M)	
1	Path 26 (Northern-Southern California)	PG&E, SCE	1534	22.519	832	10.456	16.488
2	Los Banos North (LBN)	PG&E, TID	-	-	167	1.999	1.000
3	Path 61 (Lugo-Victorville)	SCE, LADWP	-	-	308	1.755	0.878
4	Central California Area (CCA)	PG&E	1	0.010	106	0.852	0.431
5	Kramer area	SCE	45	0.377	7	0.030	0.339
6	Inyo area	SCE	88	0.027	902	0.363	0.195
7	Mirage – Devers area	SCE	52	0.276	17	0.052	0.164
8	Greater Bay Area (GBA)	PG&E	15	0.025	16	0.039	0.032
9	Big Creek Area	SCE	-	-	2	0.018	0.009
10	San Diego Area (SDA)	SDG&E	270	0.000	494	0.017	0.009
11	Path 25 (PacifiCorp/PG&E 115 kV Interconnection)	PG&E, PacifiCorp	-	-	40	0.007	0.004
12	Path 24 (PG&E-Sierra)	PG&E, SPP	-	-	17	0.004	0.002

Considering the identified congestion from this study, the ISO then reviewed economic planning study requests received to develop a list of high priority studies, consistent with tariff section tariff Section 24.3.4.2.

As part of the requirements under the ISO tariff and Business Practice Manual, Economic Planning Study Requests based on the 2011-2012 Transmission Plan were submitted to the ISO during the comment period following the stakeholder meeting to discuss the study plan. Table 5.6-2 lists the Study Requests the ISO received for this planning cycle.

Table 5.6-2: Submitted Economic Planning Study Requests

No	Name	Description	Submitted by
1	Zephyr	Between Southern Nevada and the other load centers in Southern California.	Zephyr Power Transmission, LLC
2	TransWest Express	DC transmission system to provide transmission capacity between the Intermountain and Desert Southwest regions, including California	TransWest Express, LLC
3	Delaney-Colorado River 500 kV	A new 110-mile 500 kV transmission from APS to SCE area. The line is electrically in parallel with the existing Palo Verde – Colorado River 500 kV line	Arizona Public Service (APS)

In evaluation of the identified congestion (in Table 5.6-1) and review of the study requests (in Table 5.6-2), the ISO determined the high priority studies during the 2012-2013 transmission planning cycle. The determination is described as follows.

Based on past studies and identified congestion in the study results discussed above, the following three paths were selected for high priority studies:

- Path 26 (Northern-Southern California)
- Los Banos North (LBA)
- Central California Area (CCA)

The fourth high priority study was identified based on past study results and ongoing operational concerns when COI and PDCI transfers are high during high hydro output in the Northwest. This high priority study is also in consideration of recent WECC TEPPC studies that raised COI congestion as a concern. In this ISO economic planning study, this high priority study is named:

- Pacific Northwest – California (NWC)

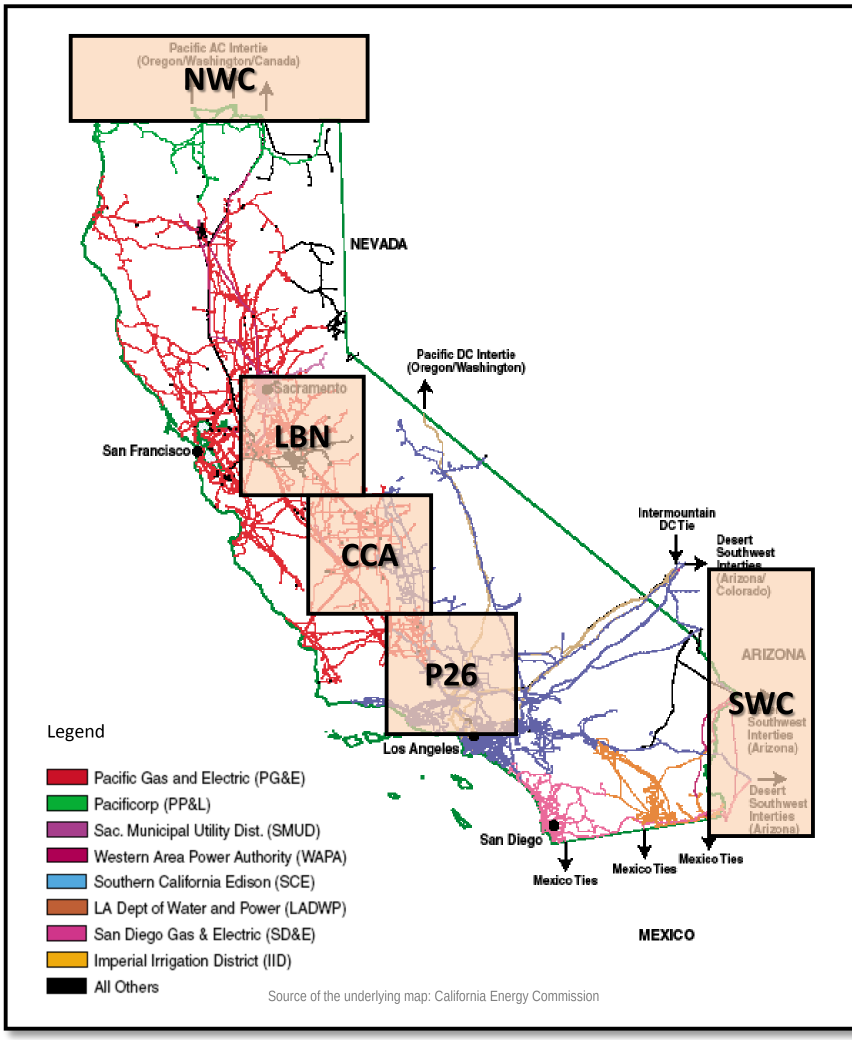
The fifth high priority study was identified based on the identified congestion on Path 61, Path 26 and in Mirage – Devers area, where the congestion limits the import to Southern California. At the same time, this high priority study covers the third economic study requests listed in Table 5.6-2. This high priority study covers a range of options, not just the study request of the Delany – Colorado River 500 kV line. This high priority study is named:

- Desert Southwest – California (SWC)

The ISO notes that the economic study requests from Zephyr Power Transmission, LLC and TransWest Express, LLC were focused on bringing renewable resources from other regions in WECC to the southeastern borders of the ISO controlled grid. As set forth in tariff section 24.3.4.1, the proposed transmission facilities in these economic study requests did not identify or project congestion, nor did the study requests address local capacity requirements. Furthermore, these study requests do not address delivery of location-constrained resources nor are they intended to access generation from an energy resource area that has been designated as such by the CPUC and the CEC, or certified by the ISO Governing Board as meeting the requirements of an energy resource area. As discussed in Chapter 2, the ISO's planning methodology is based on the renewable portfolios developed by the CPUC with the assistance of the CEC and ISO; these portfolios do not reflect the generation proposed by Zephyr Power Transmission, LLC and TransWest Express, LLC and accordingly those resources were not modeled exploring the benefits of further reinforcements into the Desert Southwest. However, the ISO did conduct a power flow and stability sensitivity analysis of the impacts of an additional high out-of-state resource, set out in Section 4.5.

Figure 5.6-1 shows geographic locations of the five high priority studies.

Figure 5.6-1: Overview of the five economic planning studies



Study ID	Study subject
P26	Path 26 Northern - Southern CA
LBN	Los Banos North
CCA	Central California Area
NWC	Pacific Northwest - California
SWC	Desert Southwest - California

5.7 Congestion Mitigation and Economic Assessment

Congestion mitigation is the second step in the economic planning study. With a focus on high-ranking congestion, this study step proposed network upgrades, evaluated their economic benefits and weighed the benefits against the costs. In this way, the study determined if the network upgrades were economical.

This section describes study results of congestion mitigation analysis and economic assessment of proposed network upgrades.

The high-priority studies are described in the following subsections. Each subsection is organized in the following parts:

(1) System overview,

(2) Studied network upgrades,

(3) Congestion analysis,

(4) Economic assessment,

(5) Summary and

(6) Recommendation

5.7.1 Path 26 (Northern-Southern California)

This section describes the economic planning study of Path 26 (Northern-Southern California).

5.7.1.1 System overview

Path 26 is a transmission link that connects the northern and southern utility areas in the state. Figure 5.7-1 and Figure 5.7-2 are system diagrams of the Path 26 area.

Figure 5.7-1: Geographic diagram of the Path 26 area

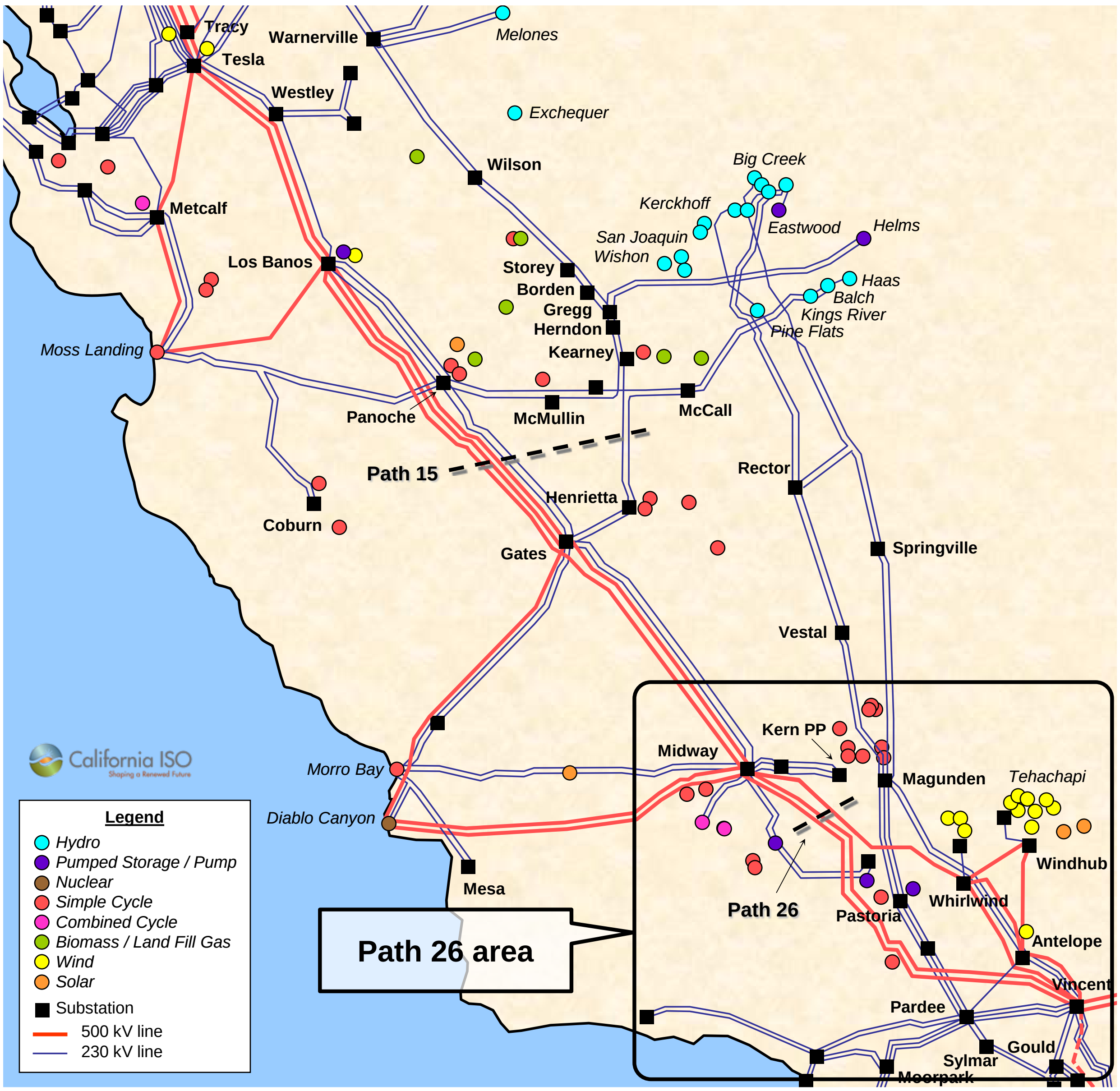
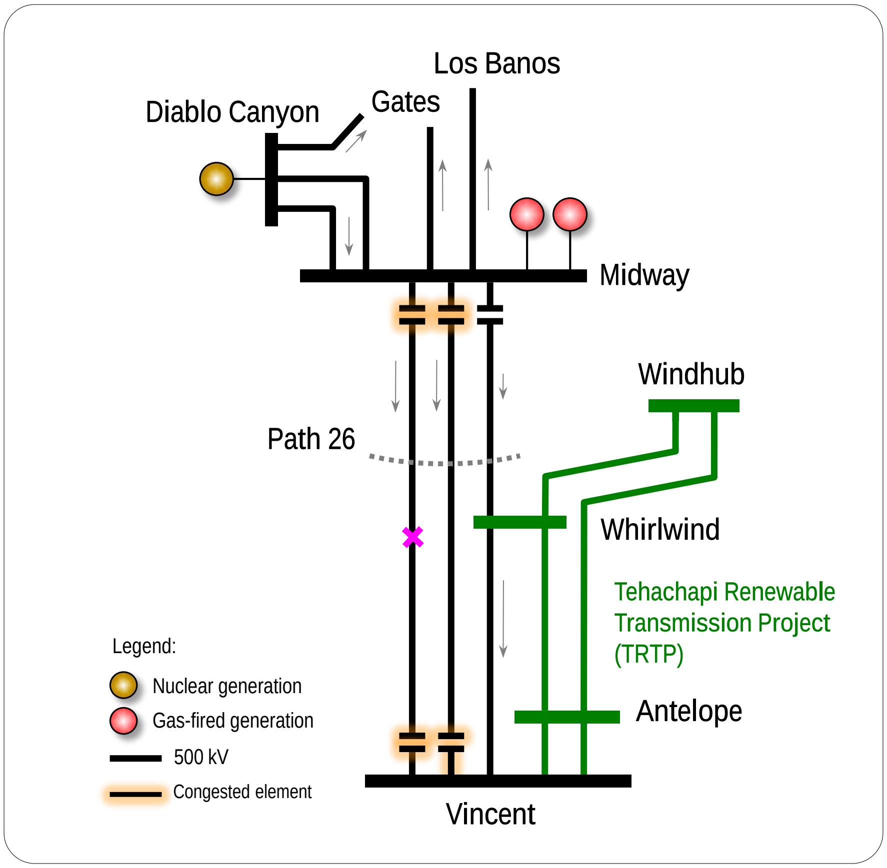


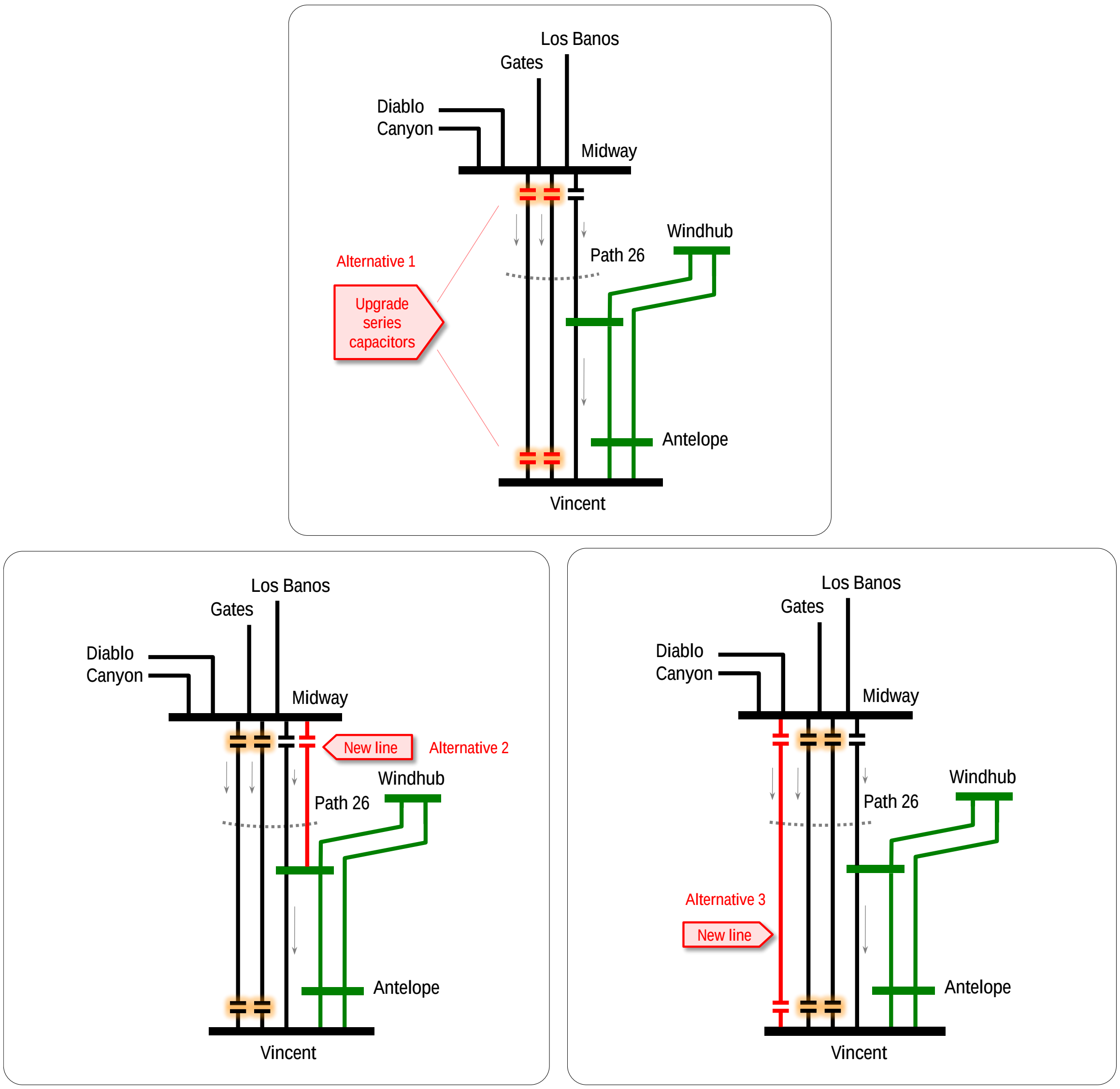
Figure 5.7-2: One-line diagram of the Path 26 area



5.7.1.2 Studied network upgrades

To alleviate Path 26 congestion, three alternative network upgrades were proposed and analyzed in this study. The three alternatives are shown in Figure 5.7-3.

Figure 5.7-3: Alternatives of proposed network upgrades under the Path 26 study



5.7.1.3 Congestion analysis

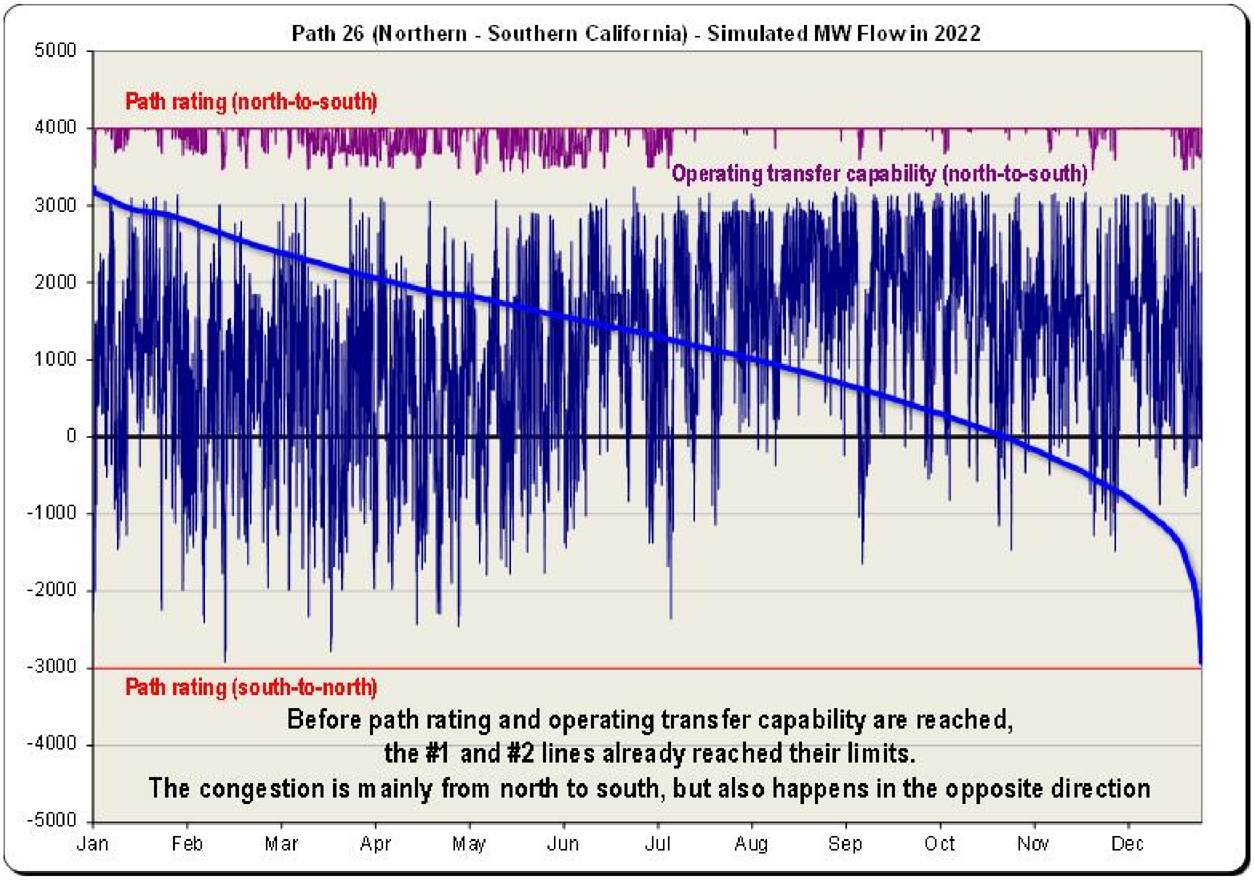
Table 5.7-1 lists the identified congestion on Path 26.

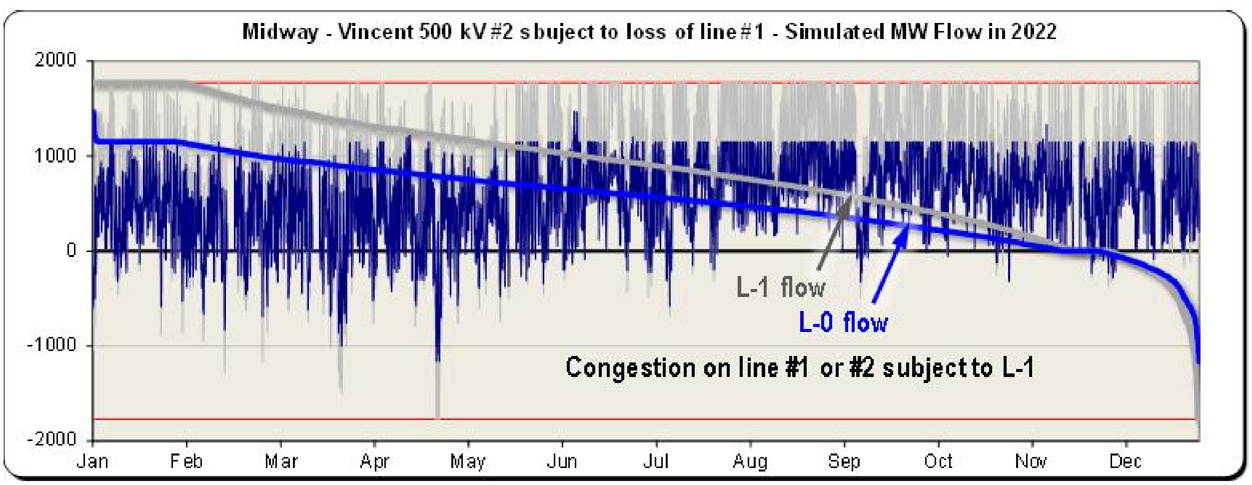
Table 5.7-1: Congested facilities on Path 26 (Northern-Southern California)

#	Transmission Facilities	Year 2017		Year 2022	
		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, or vice versa	1394	21.681	721	9.502
3	Midway – Vincent 500 kV line #1 or #2, subject to loss of Midway – Whirlwind line	140	0.838	100	0.671
4	Midway – Vincent 500 kV line #1, subject to loss of #2 line (south-to-north direction)	-	-	11	0.283

Figure 5.7-4 shows simulated power flow on Path 26.

Figure 5.7-4: Simulated Power Flow on Path 26 and individual line





As shown in Table 5.7-1 and shown in Figure 5.7-2, 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 mainly from north to south; but from south to north direction, congestion also happens.

Table 5.7-2 lists simulation results of congestion hours before and after the studied network upgrades are applied.

Table 5.7-2: Congested hours before and after Path 26 network upgrades are applied

#	Transmission Facilities	Year 2017				Year 2022			
		Status quo	Alt-1	Alt-2	Alt-3	Status quo	Alt-1	Alt-2	Alt-3
1	Midway – Vincent 500 kV line #1, subject to loss of #2 line, or vice versa	1394	30	879	40	721	7	391	17
2	Midway – Vincent 500 kV line #1 or #2, subject to loss of Midway – Whirlwind 500 kV line	140	-	23	9	100	-	25	7
3	Midway – Vincent 500 kV line #1 or #2, subject to loss of Midway – Antelope 500 kV line	-	-	5	-		-	3	-
4	Midway – Vincent 500 kV line #1 or #2, subject to loss of #2 line (south-to-north direction)	-	-	-	-	11	-	-	-
5	Midway – Whirlwind 500 kV line, subject to loss of Midway – Vincent 500 kV line #1 or #2	-	15	-	-	-	12	-	-
6	Path 26 rating north to south	-	438	-	-	-	151	-	-
7	Path 26 rating south to north	-	-	-	-	-	3	-	-
8	Path 26 operating transfer capability (OTC) north to south	-	-	234	-	-	-	-	87

5.7.1.4 *Economic assessment*

Table 5.7-3 shows cost estimates for the proposed network upgrades with the assumption to be in service in 2017. Table 5.7-4 lists quantified economic benefits. Table 5.7-5 provides a cost-benefit analysis.

Table 5.7-3: Cost estimates for the proposed network upgrades 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 – Vincent 500 kV line #4 (~110 miles)	$1,100M	$1,595M

Table 5.7-4: Benefit quantification for the proposed network upgrades for Path 26

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses[33]	Total	
1	Upgrade series capacitors of the Midway – Vincent 500 kV lines #1 and #2	2017	~$0M	-	-	~$0M	~$0M
		2022	~$0M	-	-	~$0M	
2	Build new Midway – Whirlwind 500 kV #2	2017	~$0M	-	$1M	~$0M	~$0M
		2022	~$0M	-	$1M	~$0M	
3	Build new Midway – Vincent 500 kV line #4	2017	~$0M	-	$2M	~$0M	~$0M
		2022	~$0M	-	$2M	~$0M	

Table 5.7-5: Cost-benefit analysis of the proposed network upgrades 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	~$0M	~($261M)	-
2	Build new Midway – Whirlwind 500 kV #2	$580M	~$0M	~($580M)	-
3	Build new Midway – Vincent 500 kV line #4	$1,595M	~$0M	~($1,595M)	-

[33] The losses benefits were roughly assumed values in absence of power flow computation

From the above results, it can be seen that although there is significant congestion on Path 26, the economic benefits of the proposed network upgrades are small. This is because Path 26 lies in the middle of the ISO-controlled grid and that loads in northern and southern of Path 26 systems are about the same. Relieving the congestion will cause the LMP to rise on one side and drop on the other side. As a result, the economic benefits in the northern and southern systems cancel each other.

5.7.1.5 Summary

Path 26 is a critical link in the California transmission system. Path 26 operational limits will often be significantly lower than the 4000 MW path rating when the new Whirlwind 500 kV substation is looped into the Midway – Vincent line #3. The most limiting conditions are L-1 situations on Path 26 lines. The most limiting elements are the series capacitors on Midway – Vincent #1 and #2 lines.

This economic planning study identified significant congestion on the Path 26, consistent with Path 26 congestion being top-ranked in the ISO studies for four consecutive years.

However, based on the economic assessment, none of studied network upgrades are cost effective to mitigate the congestion. While the options studied reduce the volume of congestion on the path, the reduction in congestion does not translate into material economic benefits. A main reason of small economic benefit is that when the north-to-south congestion is relieved on Path 26, the southern LMP will subside while northern LMP will rise. As the northern and southern systems are about the same size in load, the economic benefits largely canceled out by the decreased cost in the south and increased cost in the north. As well, the congestion itself does not directly translate into the presence of a reliability risk.

It is noted that despite the net benefits of all studied options being negative, Alternative 1 (“Upgrading series capacitors for Midway – Vincent 500 kV lines #1 and 2”) is more cost effective than the other two alternatives.

Path 26 congestion is also observed in present operations reality, and is managed through the congestion management functions in the ISO market.

5.7.1.6 Recommendation

As Path 26 is a critical link in the California transmission system, the ISO will continue to analyze this congestion issue in future studies. In absence of economic justification, this transmission bottleneck will be handled by congestion management in market operations.

5.7.2 Los Banos North (LBN)

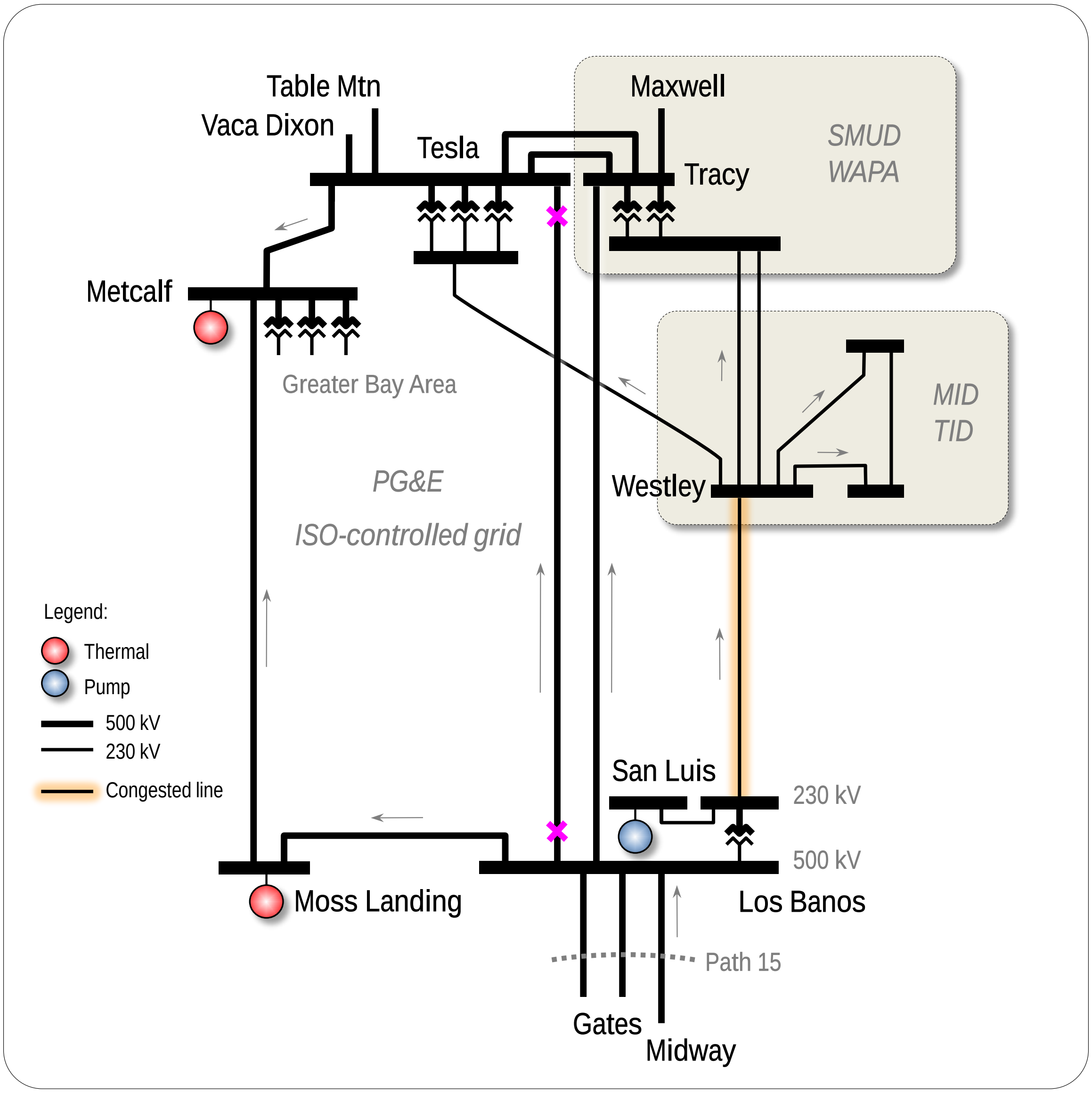
This section describes the economic planning study of Los Banos North (LBN), which is an area in the north of central California transmission system.

5.7.2.1 System overview

Figure 5.7- 5 and Figure 5.7-6 show system diagrams of the Los Banos North (LBN) area.

Figure 5.7-5: Geographic diagram of the Los Banos North (LBN) area

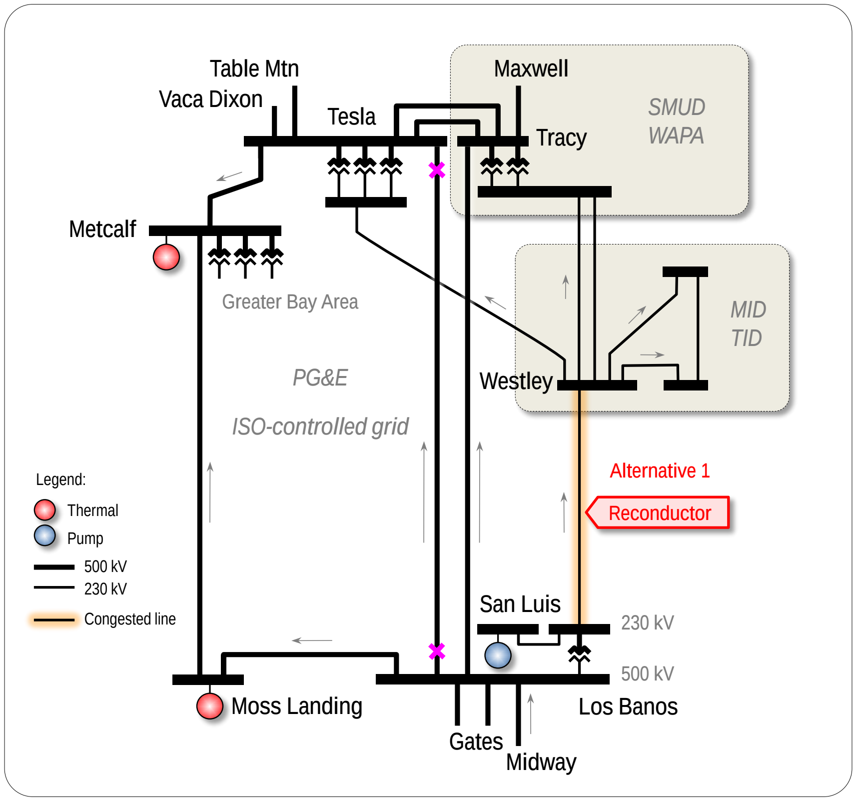
Figure 5.7-6: One-line diagram of the Los Banos North (LBN) area

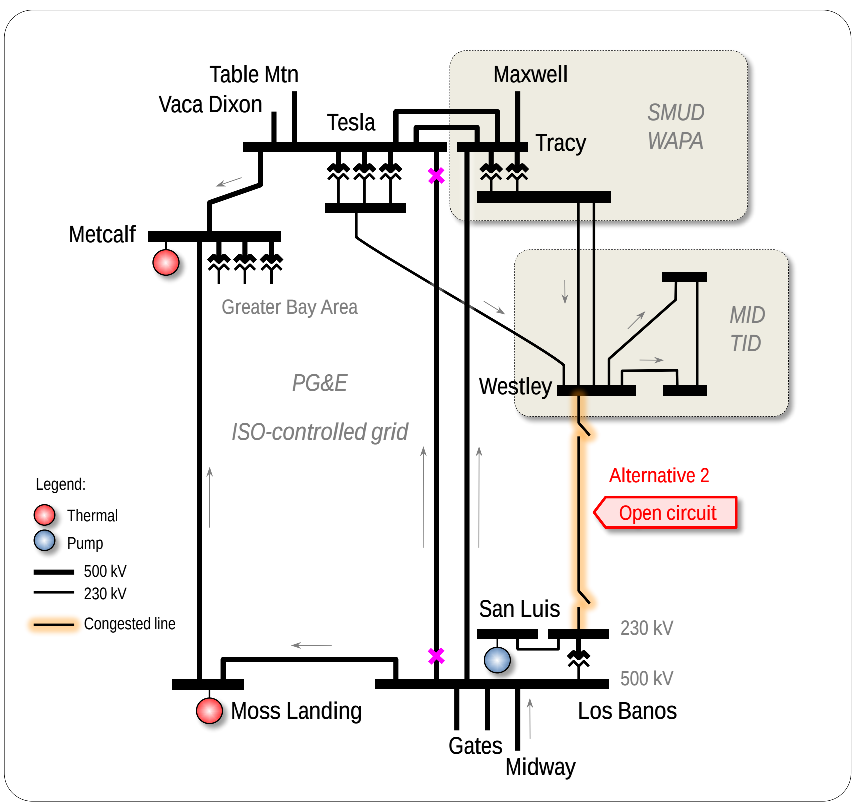


5.7.2.2 Studied network upgrades

This study evaluated two alternatives to mitigate the congestion on the Los Banos – Westley 230 kV line. The network configurations of the two alternatives are shown in Figure 5.7-7.

Figure 5.7-7: Alternatives of proposed network upgrades under the LBN study





5.7.2.3 Congestion analysis

Table 5.7-6 lists the identified congestion in this study area.

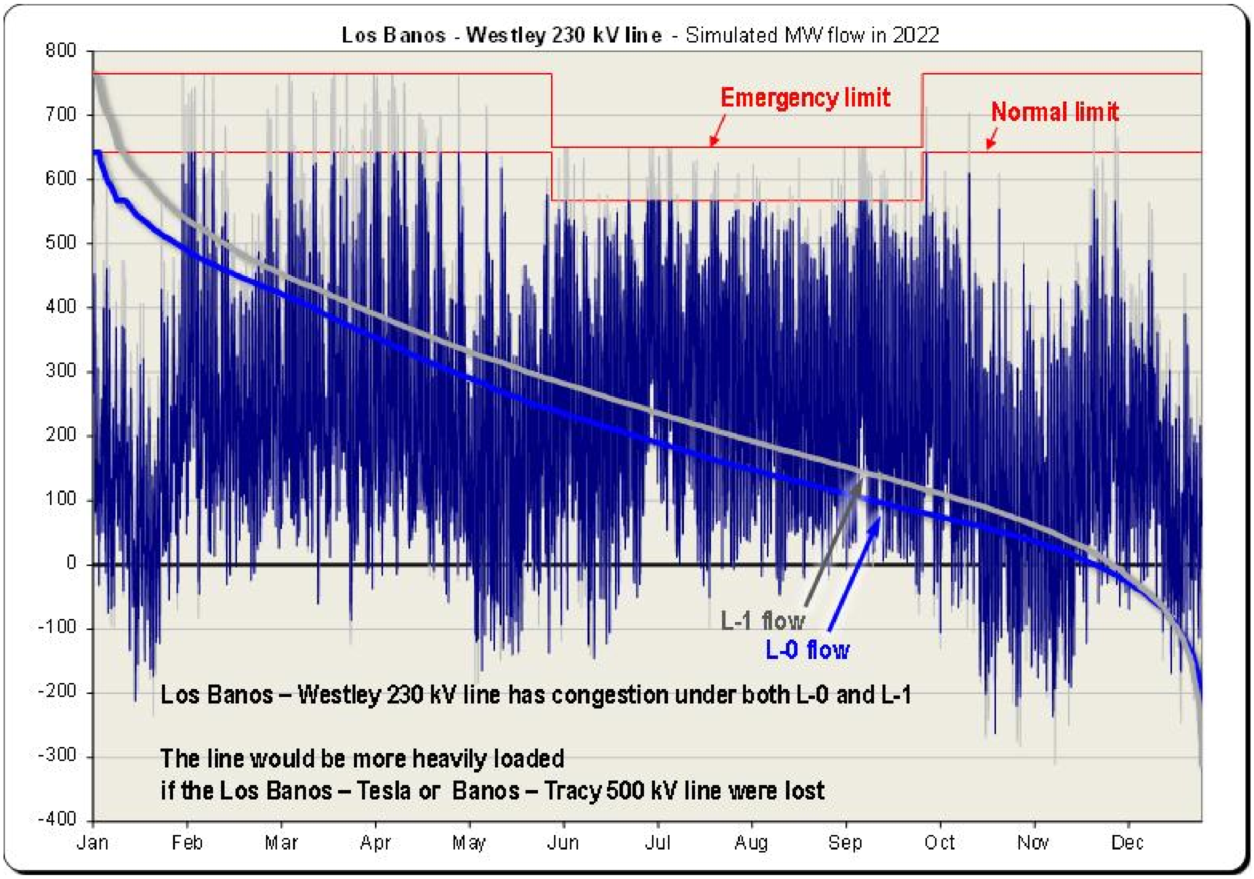
Table 5.7-6: Congested facilities in Los Banos North (LBN) area

#	Transmission Facilities	Year 2017		Year 2022	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
1	Los Banos – Westley 230 kV line	-	-	117	1.092
2	Los Banos – Westley 230 kV line, subject to loss of Los Banos – Tesla 500 kV line	-	-	48	0.903
3	Los Banos – Westley 230 kV line, subject to loss of Los Banos 500/230 kV transformer	-	-	4	0.002

The Los Banos – Westley is a transmission bottleneck in this study area. In the recent year ISO economic planning studies, the Los Banos – Westley congestion consistently ranked high in the congestion list. The direction of the Los Banos – Westley congestion is from the south to north.

Figure 5.7-8 shows simulated power flow on the Los Banos-Westley 230 kV line. It can be seen that the line is congested under both normal and contingency conditions. The congestion can happen throughout the year when the Path 15 south-to-north flow is heavy.

Figure 5.7-8: Simulated power flow on the Los Banos – Westley 230 kV line



The Los Banos – Westley 230 kV line flow is strongly correlated with the Path 15 flow. Figure 5.7-9 shows the simulated Path 15 flow.

Figure 5.7-9: Simulated Path 15 power flow

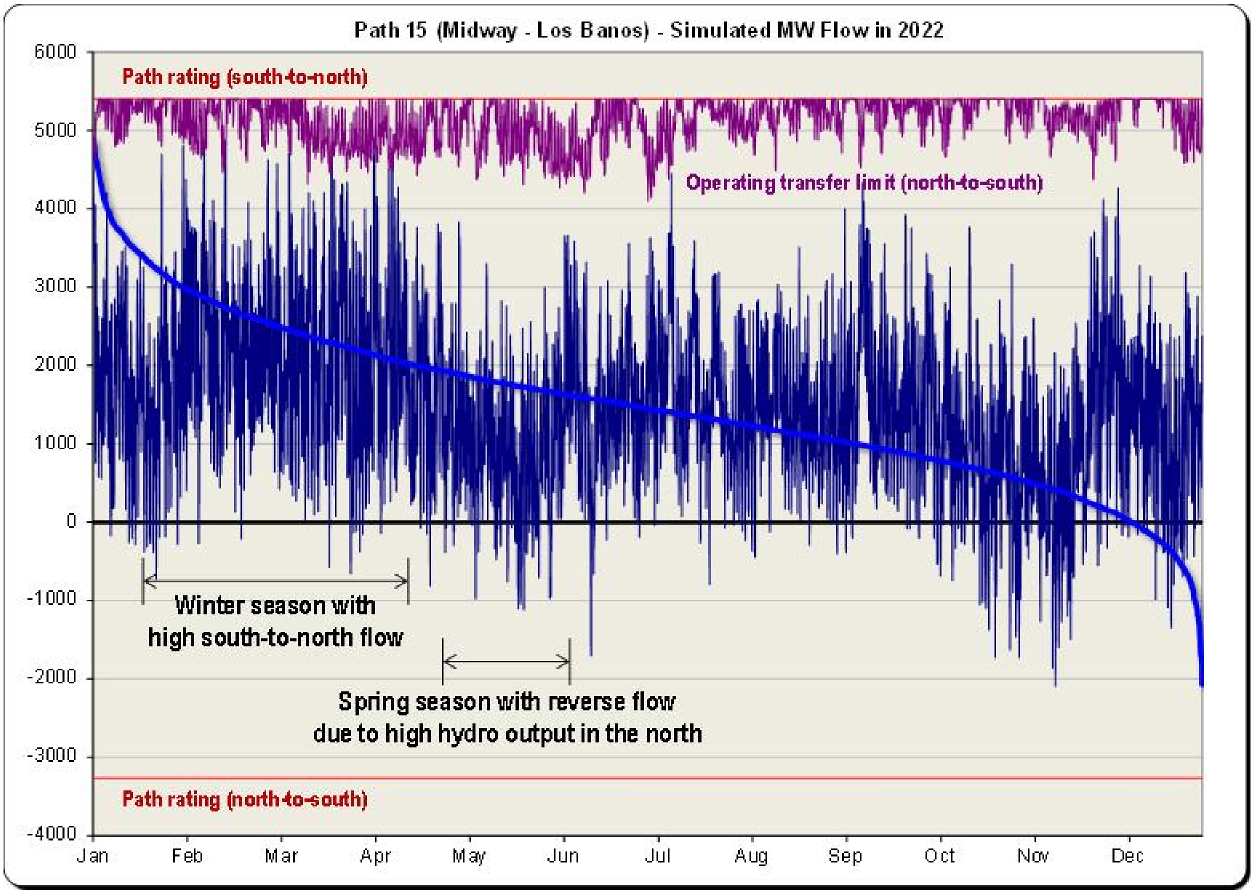


Figure 5.7-10 shows its correlation with the Los Banos – Westley 230 kV line flow. Both flows are predominantly from south to north.

Figure 5.7-10: Correlation between Path 15 and Los Banos – Westley 230 kV line flow

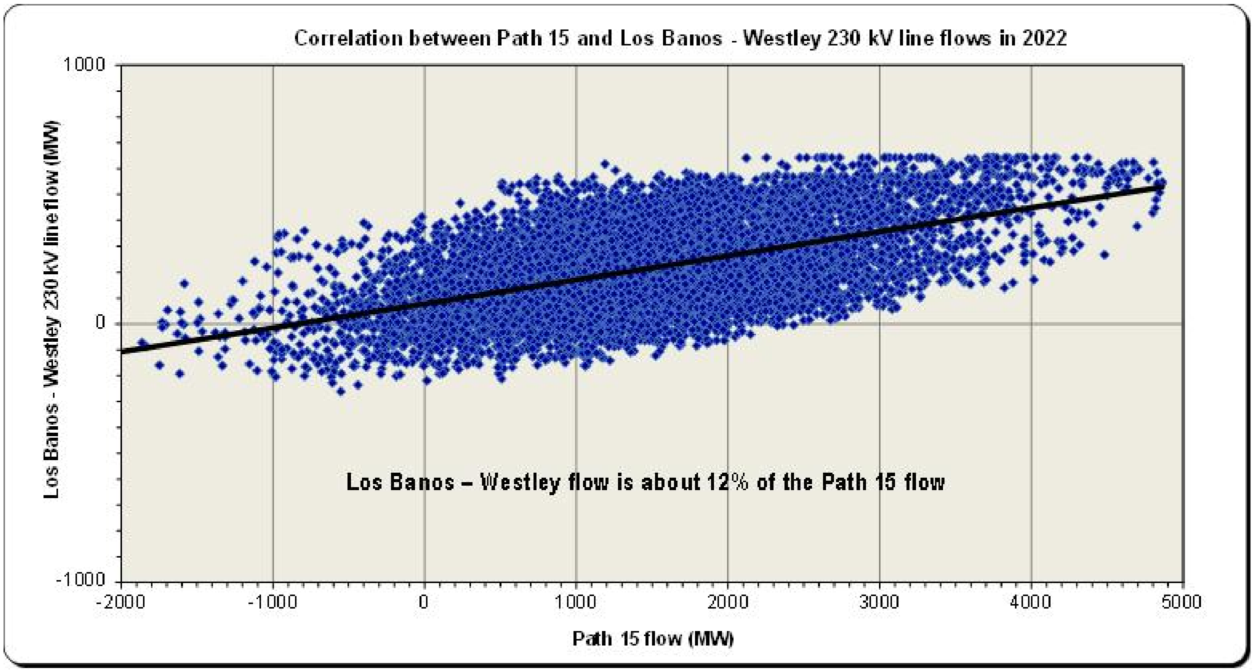


Table 5.7-7 lists simulation results of congestion hours before and after the studied network upgrades are applied.

Table 5.7-7: Congested hours before and after LBN network upgrades are applied

#	Transmission Facilities	Year 2017			Year 2022		
		Status quo	Alt-1	Alt-2	Status quo	Alt-1	Alt-2
1	Los Banos – Westley 230 kV line	-	-	-	117	-	
2	Los Banos – Westley 230 kV line, subject to loss of Los Banos – Tesla 500 kV line	-	-	-	48	-	-
3	Los Banos – Westley 230 kV line, subject to loss of Los Banos 500/230 kV transformer	-	-	-	4	-	-

5.7.2.4 Economic assessment

Table 5.7-8 shows cost estimates for the proposed network upgrade. Table 5.7-9 lists quantified economic benefits. Table 5.7-10 provides a cost-benefit analysis.

Table 5.7-8: Cost estimates for the proposed network upgrades in the LBN area

Alt.	Description	Capital Cost	Total Cost
1	Reconductor Los Banos – Westley 230 kV line (~35 miles)	$45M	$65M
2	Open up the Los Banos – Westley 230 kV line	$0M	$0M

Table 5.7-9: Benefit quantification for the proposed network upgrades in the LBN area

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Reconductor Los Banos – Westley 230 kV line	2017	~$0M	-	-	~$0M	~$0M
		2022	~$0M	-	-	~$0M	
2	Open up the Los Banos – Westley 230 kV line	2017	~$0M	-	-	~$0M	~$0M
		2022	~$0M	-	-	~$0M	

Table 5.7-10: Cost-benefit analysis of the proposed network upgrades in the LBN area

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Reconductor Los Banos – Westley 230 kV line	$65M	~$0M	~($65M)	-
2	Open up the Los Banos – Westley 230 kV line	$0M	~$0M	~$0M	-

As seen from the above table, none of the studied network upgrades can be economically justified.

5.7.2.5 Summary

In conclusion, this study did not find any economic justification for the studied network upgrades in the Los Banos North (LBN) area.

5.7.2.6 Recommendation

As the Los Banos – Westley bottleneck is a significant and re-occurring congestion; the ISO will continue to investigate this congestion area in future studies.

5.7.3 Central California Area (CCA)

This section describes the economic planning study of Central California Area (CCA).

5.7.3.1 System overview

Figure 5.7-11 is a geographic diagram of the high-voltage transmission system in Central California.

Figure 5.7-11: Geographic diagram of the Central California Area (CCA)

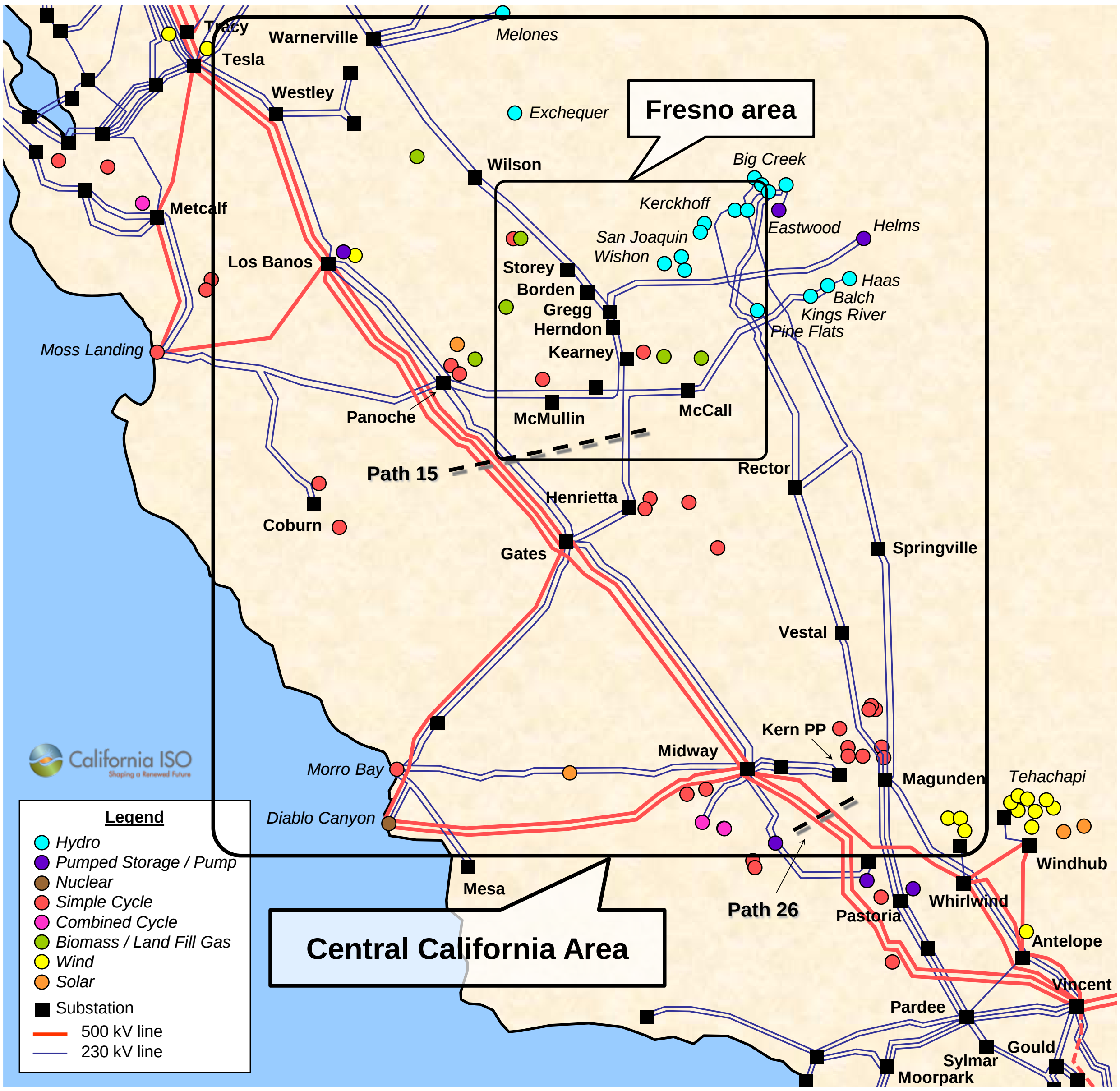


Figure 5.7-12 shows the current 230 kV network configuration of the Greater Fresno Area (GFA).

Figure 5.7-12: Greater Fresno Area (GFA) 230 kV system – status quo before 2017

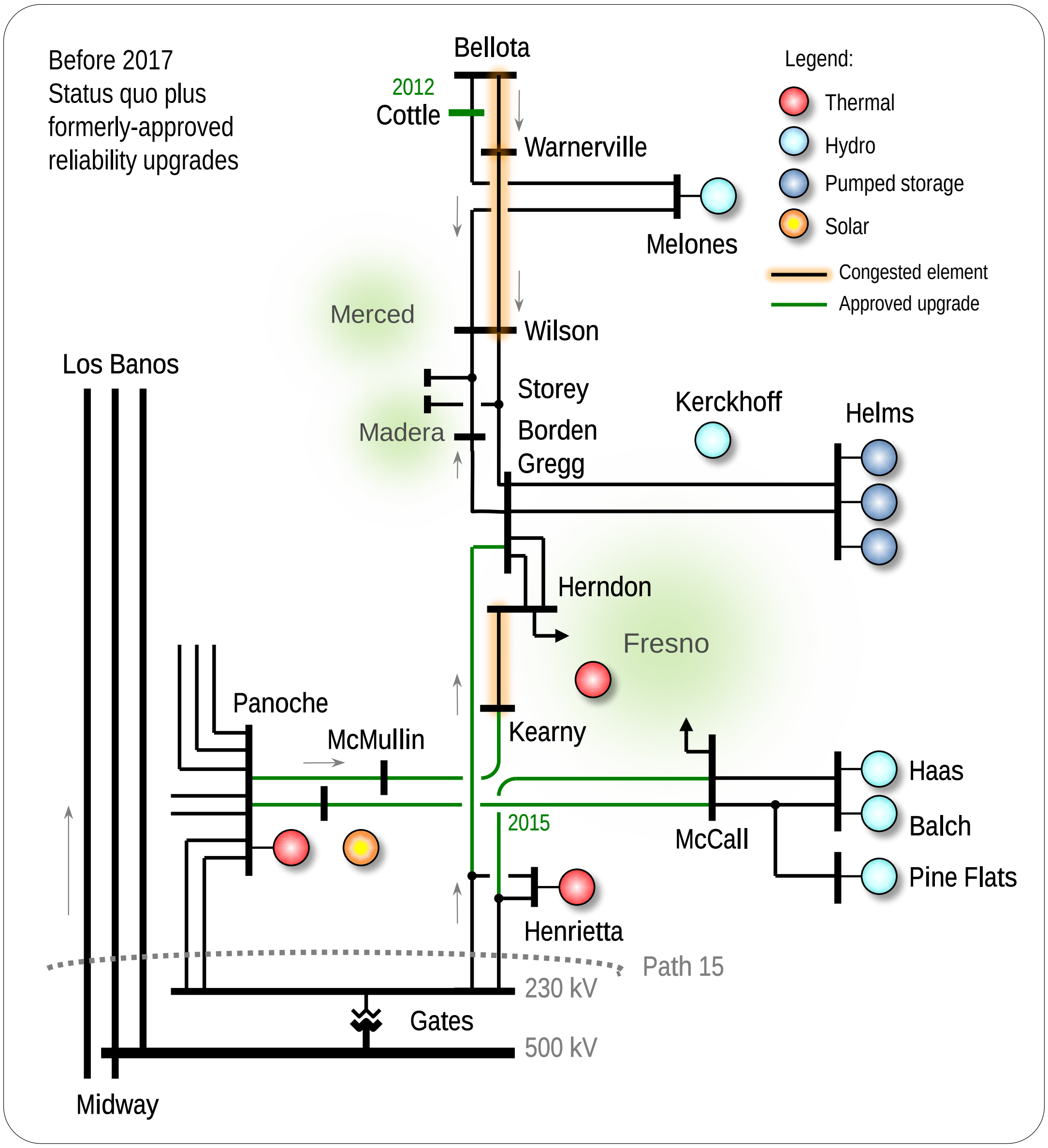
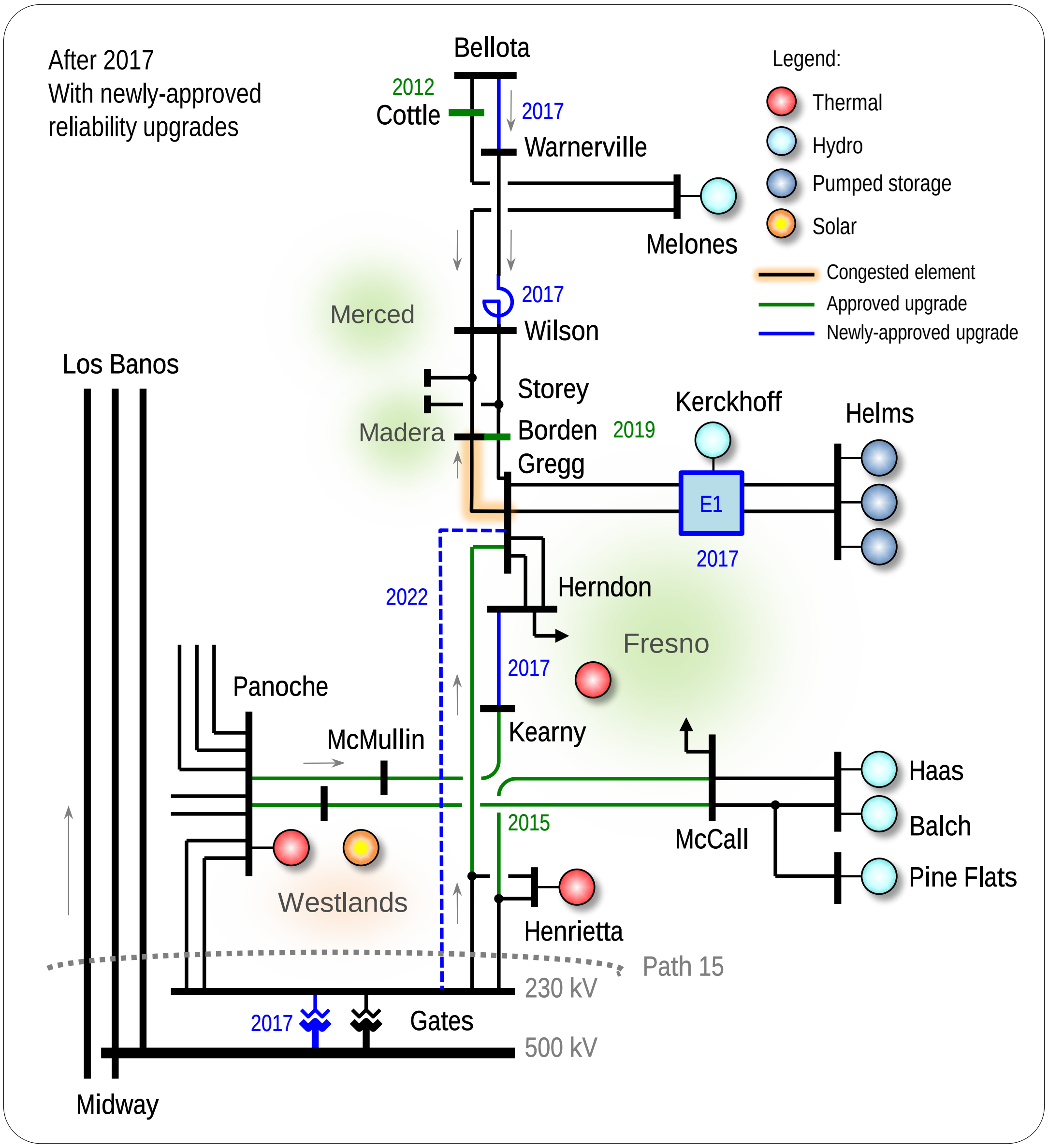


Figure 5.7-13 shows GFA 230 kV network configurations with recommended network upgrades.

Figure 5.7-13: Greater Fresno Area (GFA) 230 kV system
with recommended reliability-driven network upgrades



5.7.3.2 Studied network upgrades

With the reliability network upgrades identified in Section 3.3 (Central California Study) in the Greater Fresno Area (GFA), there is no significant congestion in this study area. Therefore, this study does not focus on any economically-driven network upgrades.

Instead, the study compared the physical performance of three alternatives and evaluated their relative economic merits. The three alternatives are:

- Alternative G: Gates – Gregg 230 kV line
- Alternative P: Panoche – Gregg 230 kV line
- Alternative L: Los Banos – Gregg 230 kV line

Figure 5.7-14 shows network configurations of the three alternatives that are compared in this study.

Figure 5.7-14: Alternatives of potential network upgrades analyzed in this study

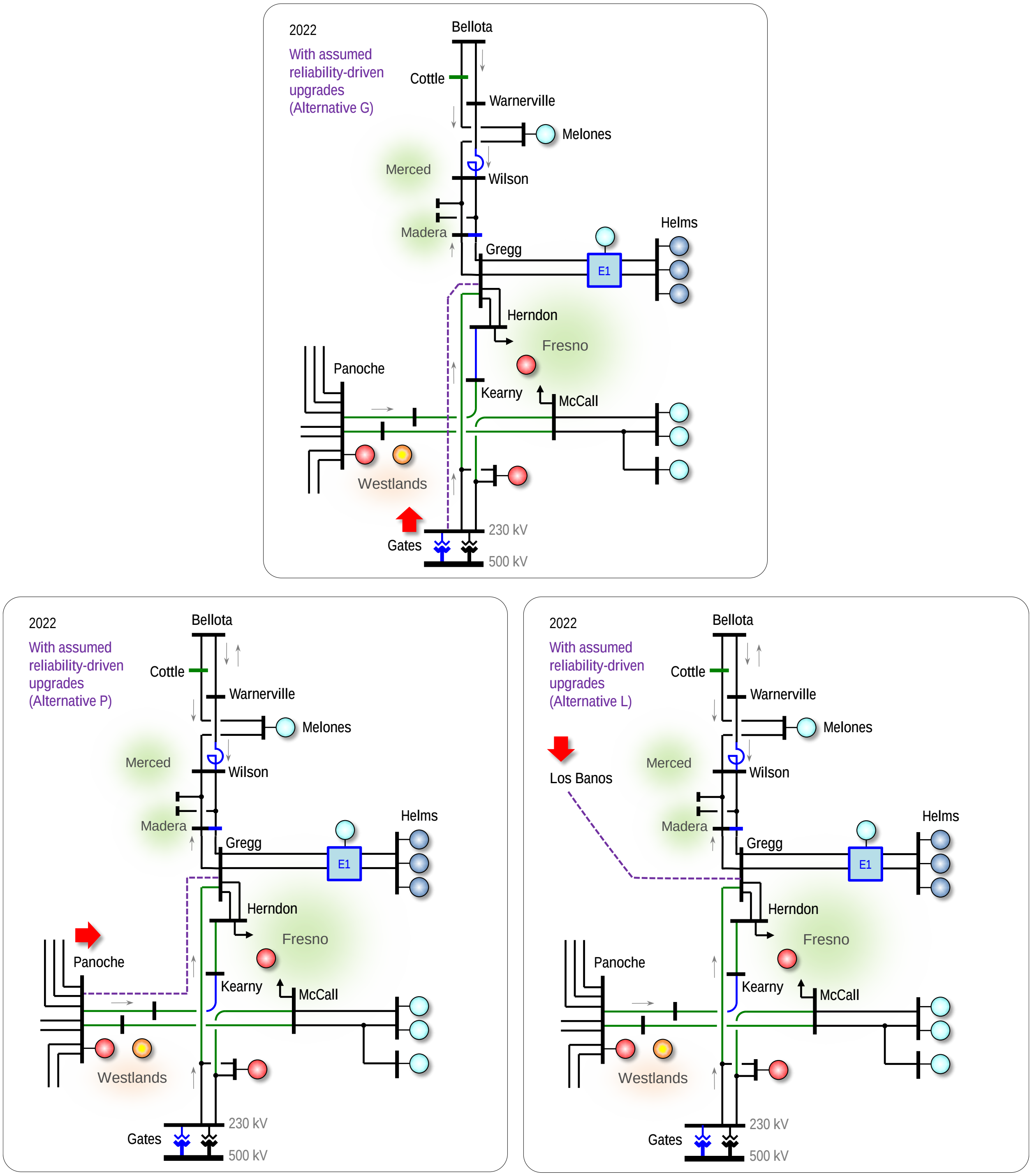


Figure 5.7-15 shows flow duration charts to compare the power flows on 230 kV lines. From this figure, it can be seen that the Gates connection delivers the best electrical performance in term of the amount of energy that the new 230 kV lines transfer. In contrast, the Los Banos connection delivers the worst electrical performance, because the lines are longer than the other alternatives.

Figure 5.7-15: Comparison of the three alternatives with 230 kV line flows

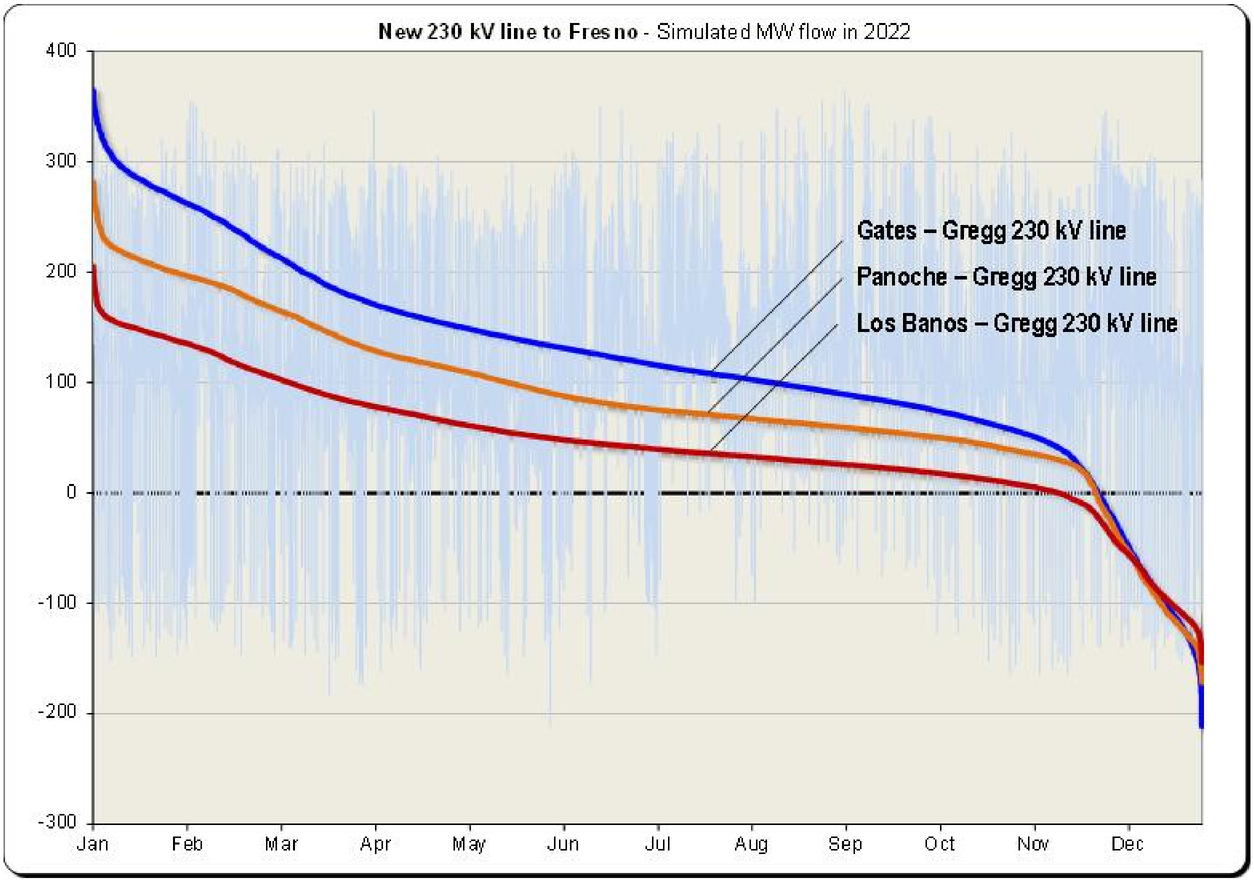


Table 5.7-11 shows cost estimates for the proposed alternatives with the assumption that the network upgrades would to be in service in 2020. Table 5.7-12 lists quantified economic benefits. Table 5.7-13 provides a cost-benefit analysis.

Table 5.7-11: Incremental cost estimates for the studied CCA alternatives

Alt.	Description	Capital Cost	Total Cost
∆(P-G)	Connect to Panoche 230 kV instead of Gates	$0M	$0M
∆(L-G)	Connect to Los Banos 230 kV instead of Gates	$100M	$145M

Note: It is assumed that the Panoche – Gregg line has the same length as the Gates – Gregg line and therefore the incremental cost is zero. It is assumed the Los Banos – Gregg line is about twice as longer than the Gate – Gregg line and that the incremental cost is assumed to be $100M.

Table 5.7-12: Incremental benefits for the studied CCA alternatives

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
∆(P-G)	Connect to Panoche 230 kV instead of Gates	2022	~$0M	-	-	~$0M	~$0M
∆(L-G)	Connect to Los Banos 230 kV instead of Gates	2022	~$0M	-	-	~$0M	~$0M

Note: It is assumed that starting from the proposed operation year 2020 and beyond the yearly benefits are the same as year 2022

Table 5.7-13: Incremental cost-benefit analysis of the studied CCA alternatives

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
∆(P-G)	Connect to Panoche 230 kV instead of Gates	$0M	~$0M	~$0M	-
∆(L-G)	Connect to Los Banos 230 kV instead of Gates	$145M	~$0M	~($145M)	-

From the above cost-benefit analysis, that there is no significant difference between Alternative G and Alternative P. However, it is obvious that Alternative L is much inferior due to its higher cost than other alternatives.

In view of both physical and economical aspects, Alternative G is a better plan than other alternatives. This suggests that for proposed new 230 kV lines to the Fresno area, starting from Gates substation is a preferred option.

5.7.3.3 Congestion analysis

Table 5.7-14 lists the identified congestion in this study area.

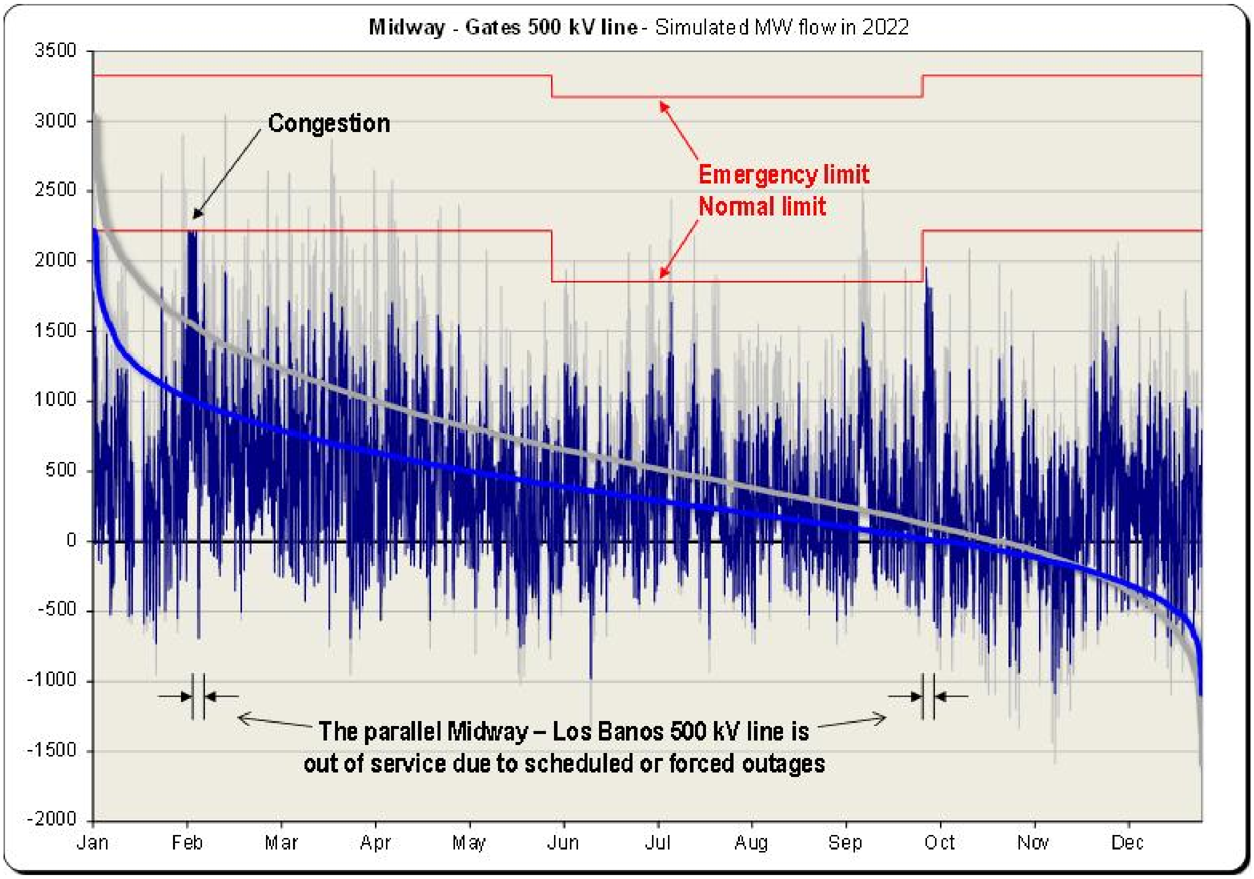
Table 5.7-14: Congested facilities in Central California Area

#	Transmission Facilities	2017		2022	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Borden – Gregg 230 kV line #1, subject to loss of Borden-Gregg 230 kV line #2	-	-	64	0.204
2	Midway – Gates 500 kV line (This congestion happens when the Midway – Los Banos 500 kV line is under outage)	-	-	10	0.168
3	Midway – Gates 230 kV line #1, subject to loss of Midway – Gates 500 kV line (This congestion happens when the Midway-Los Banos 500 kV line is under outage)	1	0.010	13	0.481
4	Path 15 (Midway-Los Banos) Operating Transfer Capability (OTC)	-	-	19	0.000

From the above table, it can be seen that there was a brief congestion on the Midway – Gates 500 kV line. The congestion was simply because the parallel Midway – Los Banos line was out of service during that particular period due to maintenance or forced outage.

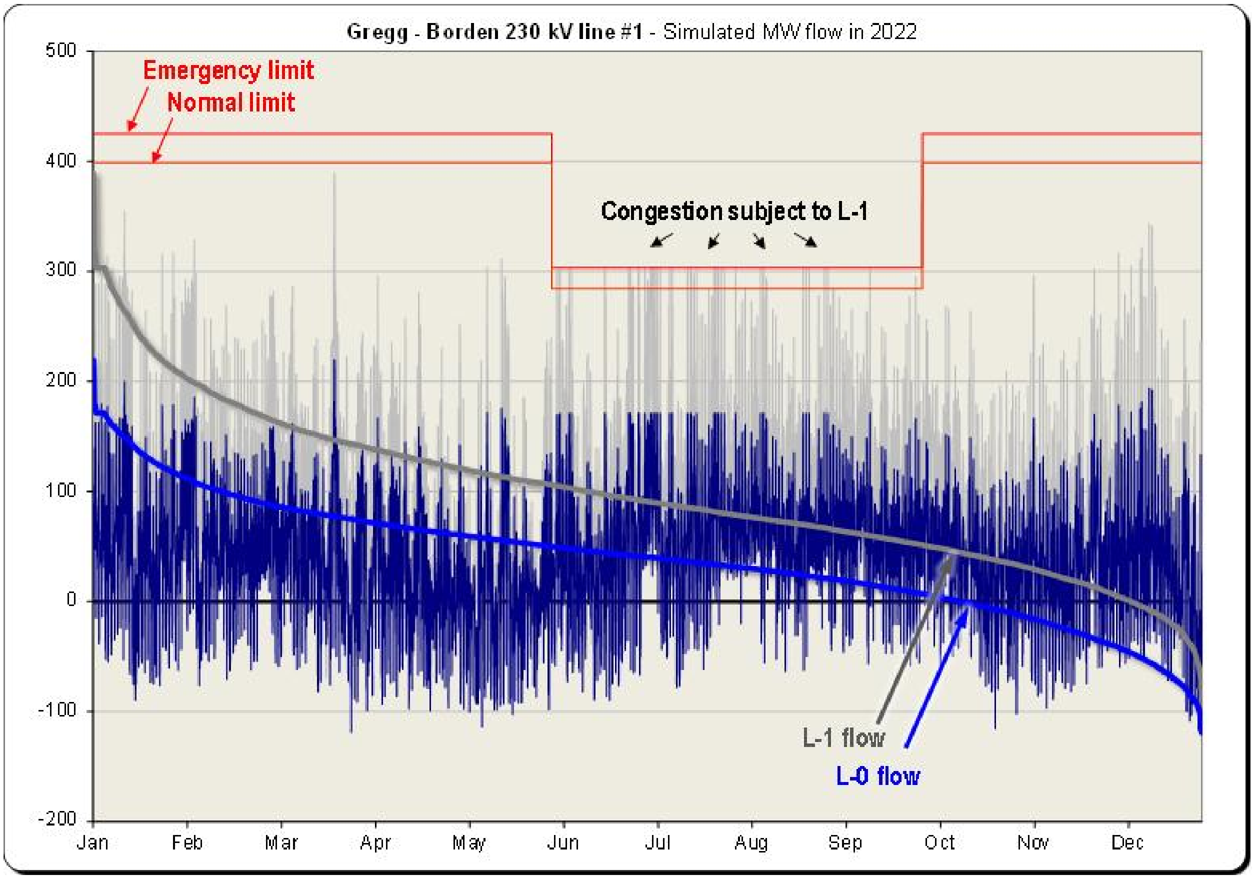
Figure 5.7-16 shows simulated power flow on the Midway – Gates 500 kV line in 2022 respectively.

Figure 5.7-16: Simulated power flow on the Midway - Gates 500 kV line



With the reliability network upgrades identified in section 3.3, the simulated congestion was light. The identified congestion was on the Gregg – Borden 230 kV line under L-1 conditions at loss of the parallel line. Figure 5.7-17 shows the simulated power flow on the Gregg – Borden 230 kV line under the L-1 conditions.

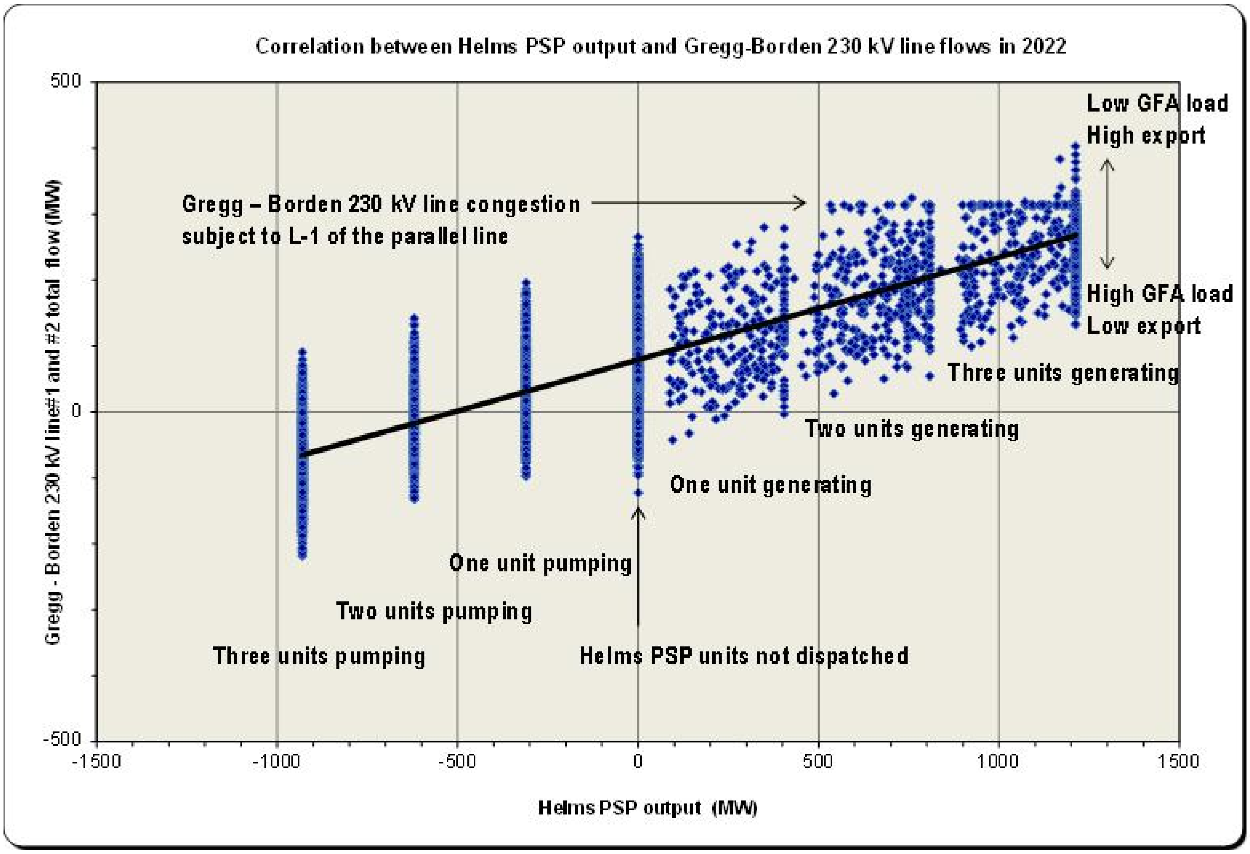
Figure 5.7-17: Simulated power flow on
the Gregg – Borden 230 kV line subject to L-1 of the parallel line



The L-1 binding condition happens when Helms PSP operates in generation mode and its output is high and the Gregg-Borden line flow.

Figure 5.7-18 shows the correlation of Helms generation output and the Gregg-Borden line flow.

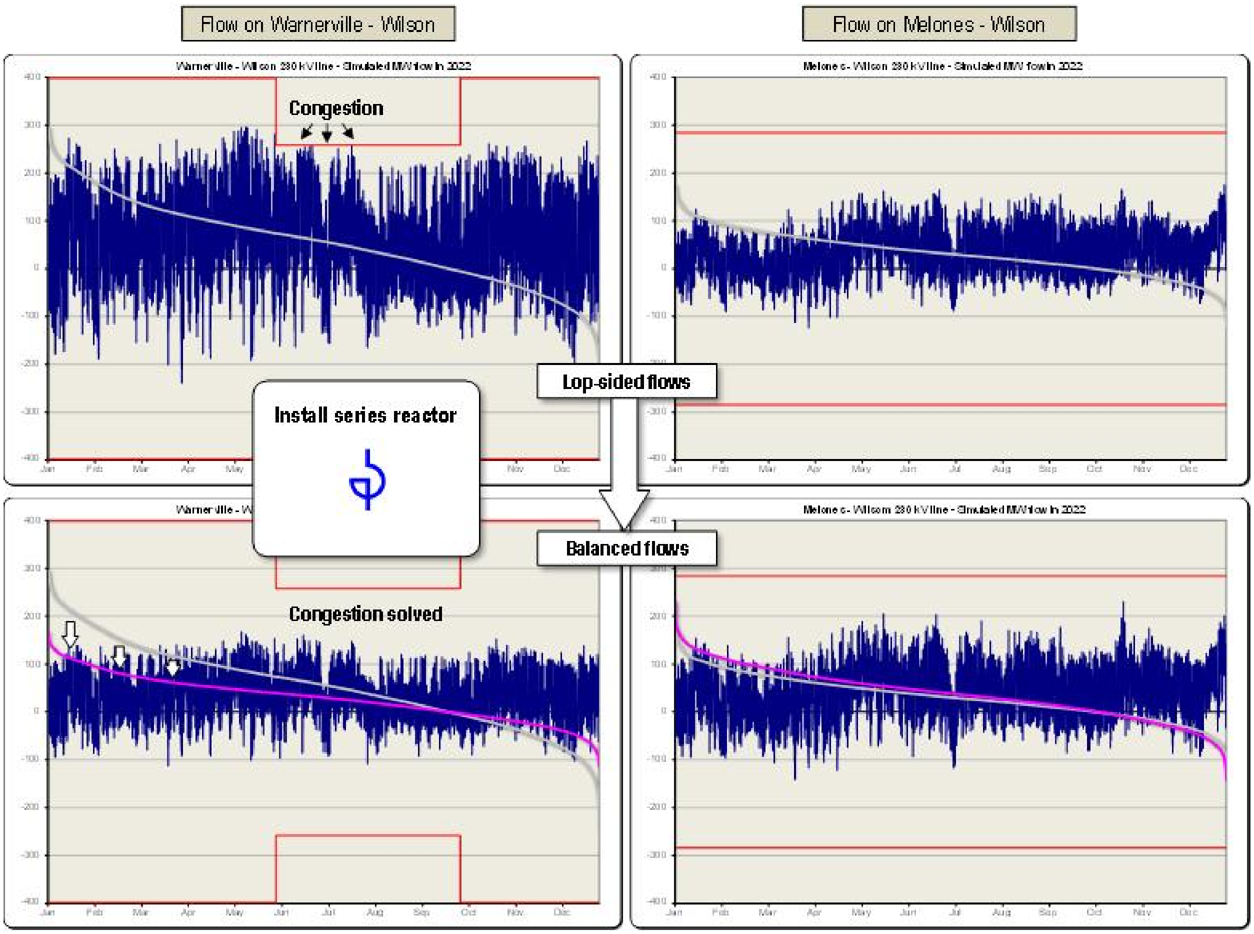
Figure 5.7-18: Correlation of Helms PSP output and Gregg – Borden 230 kV line flows



From Figure 5.7-18, it can be seen that the L-1 congestion happens what three Helms units are generating. In the current system, Helms RAS (HRAS) protect the Gregg – Borden L-1 condition by tripping the 3rd Helms unit when all three units are generating. Such logic is modeled in the production simulation database, otherwise the L-1 based congestion would even be more severe.

Table 5.7-19 shows the effect of series reactor on balancing the Warnerville – Wilson and Melones – Wilson 230 kV line flows. The series reactor would reduce the flow on the Warnerville – Wilson line such that the flows are not lop-sided on the two parallel lines. At the same time, the series reactor would mitigate the congestion on the Warnerville – Wilson line.

Figure 5.7-19: Balancing power flows on the Warnerville – Wilson and Melones – Wilson 230 kV lines by installing a series reactor on the Warnerville – Wilson line



5.7.3.4 Summary

Fundamentally, the proposed network upgrades in the Central California Area are driven by the reliability needs. Thus, reliability assessment plays a dominant role in justifying the proposed network upgrades. This economic assessment with production simulation provides supporting evidences. For detailed information about the Central California study, please refer to Section 3.3.

5.7.3.5 Recommendation

If there is a need to build new transmission lines into Fresno to increase load serving capability and facilitate Helms PSP operations, it is recommended to plan the new transmission lines that start from the south and run into the Fresno area. Starting the new transmission lines from the south (e.g. Gates substation) is better than starting from the west (e.g. Panoche substation); and it is much inferior to start the new transmission line from the north (e.g. Los Banos substation). This is not only true in electrical performance but also in economic considerations. In this light, the Gates – Gregg 230 kV line recommended in Section 3.3.5 is reaffirmed as the preferred network upgrade over other alternatives.

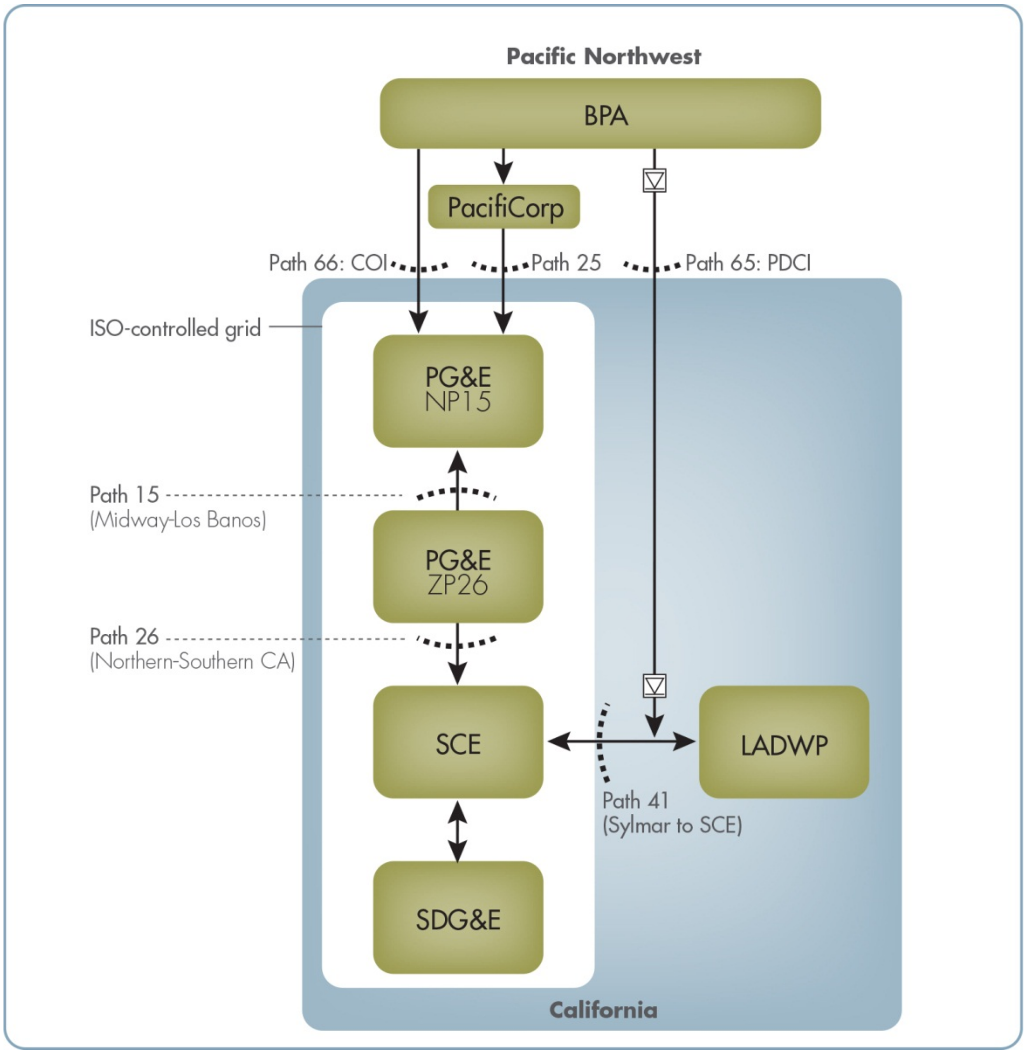
5.7.4 Pacific Northwest – California (NWC)

This section describes the economic planning study of Pacific Northwest – California (NWC) interface.

5.7.4.1 System overview

Figure 5.7-20 is a schematic diagram of the Northwest – California system configuration.

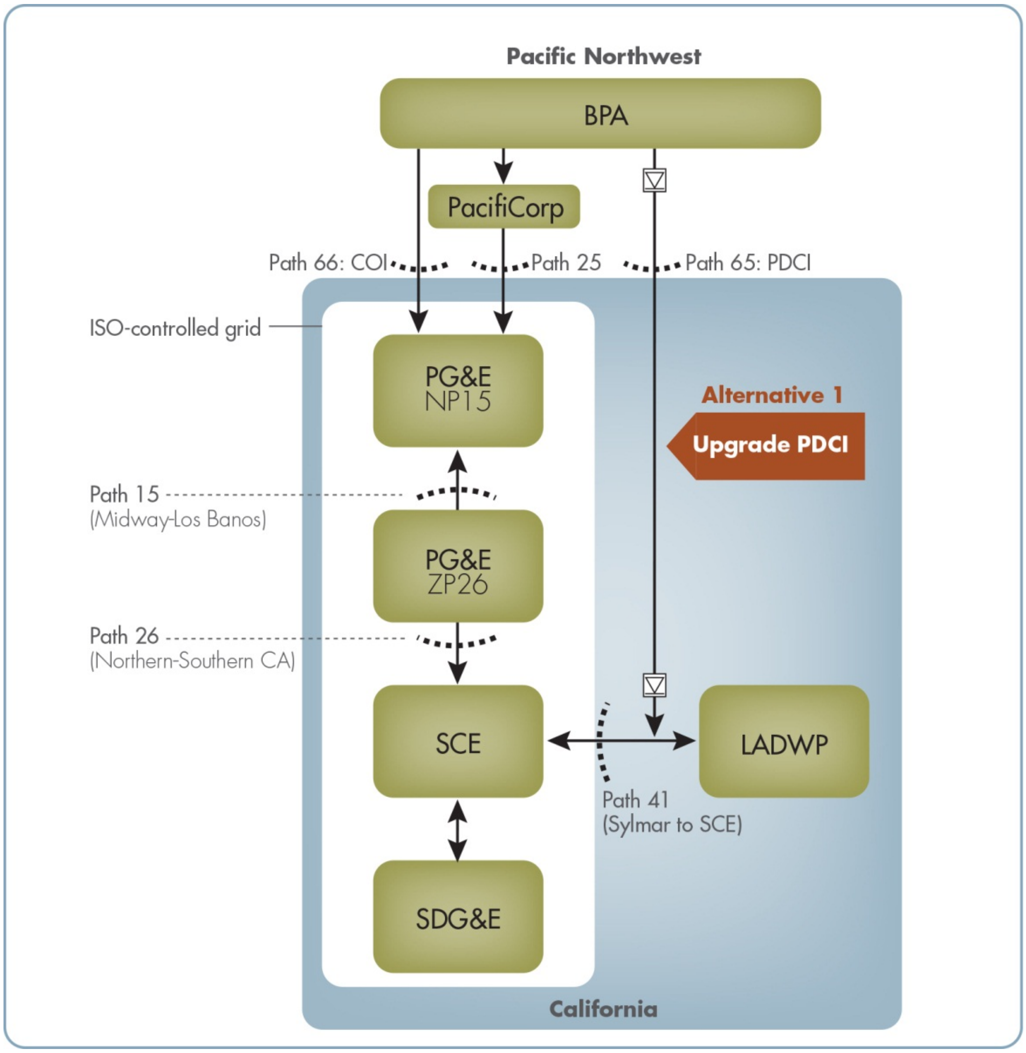
Figure 5.7-20: Pacific Northwest – California (NWC) system configuration



5.7.4.2 Studied network upgrade

Figure 5.7-21 shows the proposed PDCI upgrade analyzed in this study.

Figure 5.7-21: Proposed network upgrade under this study
(Alternative 1: Increase PDCI rating from 3220 to 3280 MW)



The present path rating of PDCI is 3,100 MW. Currently, BPA's PDCI Upgrade Project is in progress. The upgrade will increase PDCI rating by 120 MW and rating will be raised to 3,220 MW. This planning study analyzes a future potential network upgrade with an additional 500 MW increase of the PDCI rating.

5.7.4.3 Congestion analysis

Figure 5.7-22 and Figure 5.7-23 show simulated power flow on Path 66 (California-Oregon Intertie) and Path 65 (Pacific DC Intertie) respectively. On the plots, chronology and duration curves are shown for the base case; and additionally duration curves for high and low hydro scenarios are shown. The high and low scenarios are sensitivity cases constructed from historical hydro patterns according to the WECC database. The high hydro scenario is based on year 2011 wet pattern in the Western Interconnection; and the low hydro scenario is based on year 2001 dry pattern.

Figure 5.7-22: Simulated power flow on Path 66 (COI)

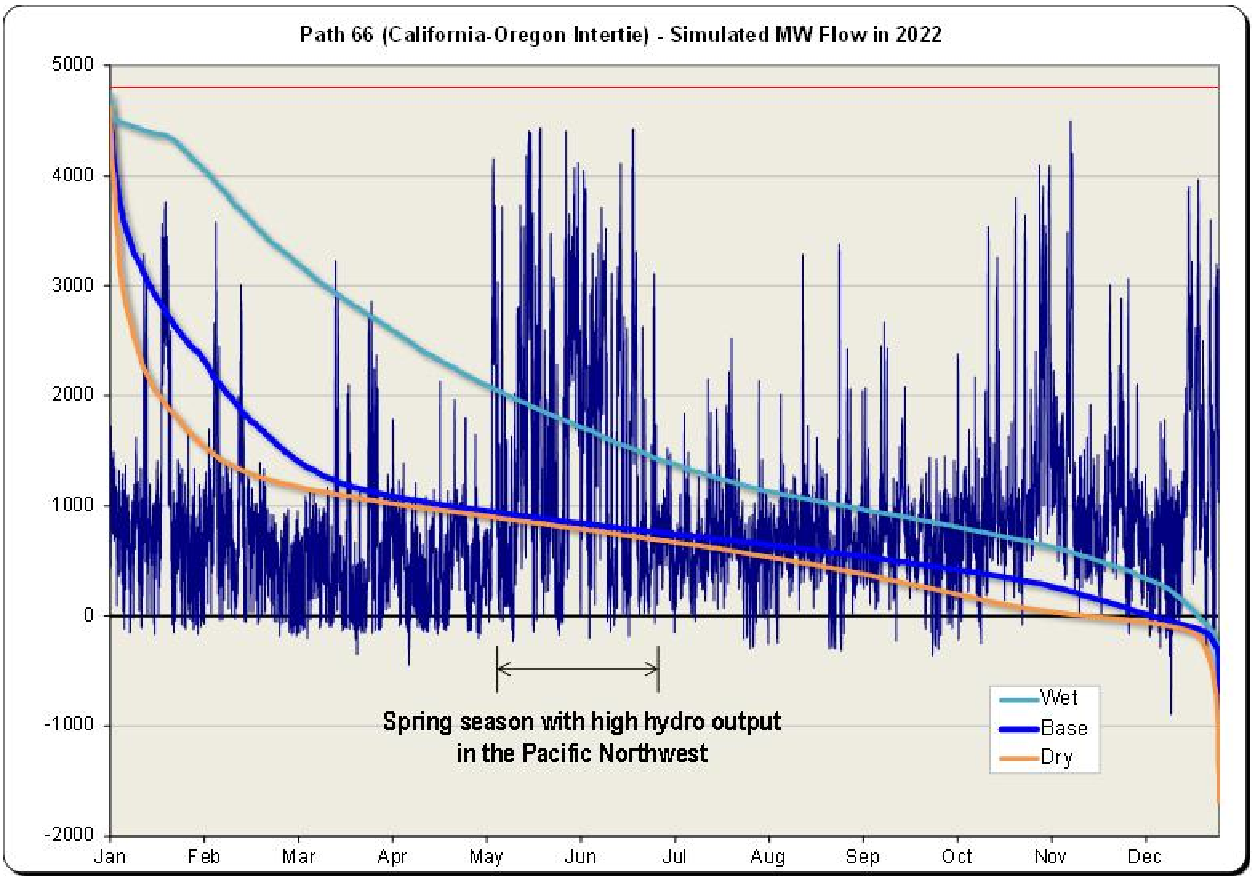
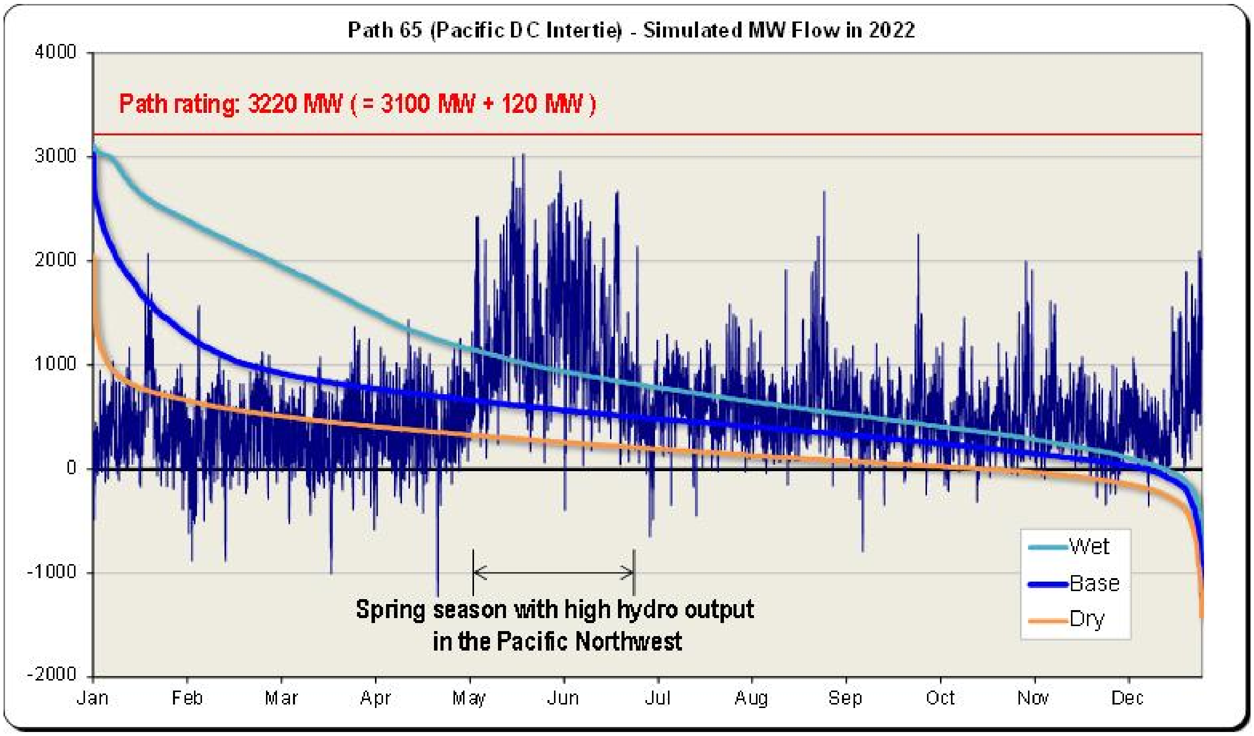


Figure 5.7-23: Simulated power flow on Path 65 (PDCI)



The production simulation did not identify any congestion in this study area. However, Figure 5.7-22 and Figure 5.7-23 do show that the transmission paths are prone to congestion during high hydro output in the Pacific Northwest.

5.7.4.4 Economic assessment

Table 5.7-15 shows cost estimates for the proposed network upgrade. Table 5.7-16 lists quantified economic benefits. Table 5.7-17 provides a cost-benefit analysis.

Table 5.7-15: Cost estimates for the proposed network upgrade in the NWC area

Alt.	Description	Capital Cost	Total Cost
1	Upgrade PDCI from 3,200 MW to 3,800 MW	$300M	$435M

Table 5.7-16: Benefit quantification for the proposed network upgrade for the NWC area

Alt.	Description	Yearly benefit					Total Benefit
		Year	Production	Capacity	Losses	Total	
1	Upgrade PDCI from 3,200 MW to 3,800 MW	2017	~$0M	($4M)	-	($4M)	($58M)
		2022	~$0M	($4M)	-	($4M)	

Table 5.7-17: Cost-benefit analysis of the proposed network upgrade in the NWC area

Alt.	Description	Total Cost	Total Benefit	Net Benefit	BCR
1	Upgrade PDCI from 3,200 MW to 3,800 MW	$435M	($58M)	($493M)	-

Because of downstream bottlenecks in the SCE system, increasing PDCI flow will increase the LCR. As a result, the capacity benefits are negative. Also, there is no economic benefit identified from production simulation.

5.7.4.5 Summary

The study did not find an economic justification for the proposed PDCI upgrade.

Path 66 (COI) and Path 65 (PDCI) are important transmission interfaces for importing power for the Pacific Northwest that is abundant with hydro and wind resources. Although this study did not find economic justifications for the proposed PDCI upgrade, it does not mean that it is not beneficial to upgrade the import transmission facilities from the Pacific Northwest. Based on future development of renewable resources and system integration needs, there may be a future need to upgrade COI and PDCI.

5.7.4.6 Recommendation

The ISO will continue to pay attention to this study area. In future studies, the ISO will continue to analyze potentially needed upgrades.

5.7.5 Desert Southwest – California (SWC)

This section describes the economic assessment of potential network upgrades in the area between Desert Southwest and California.

5.7.5.1 System overview

Figure 5.7-24 shows the transmission system in the Desert Southwest – California area. The figure also shows three proposed network upgrades analyzed in this economic assessment.

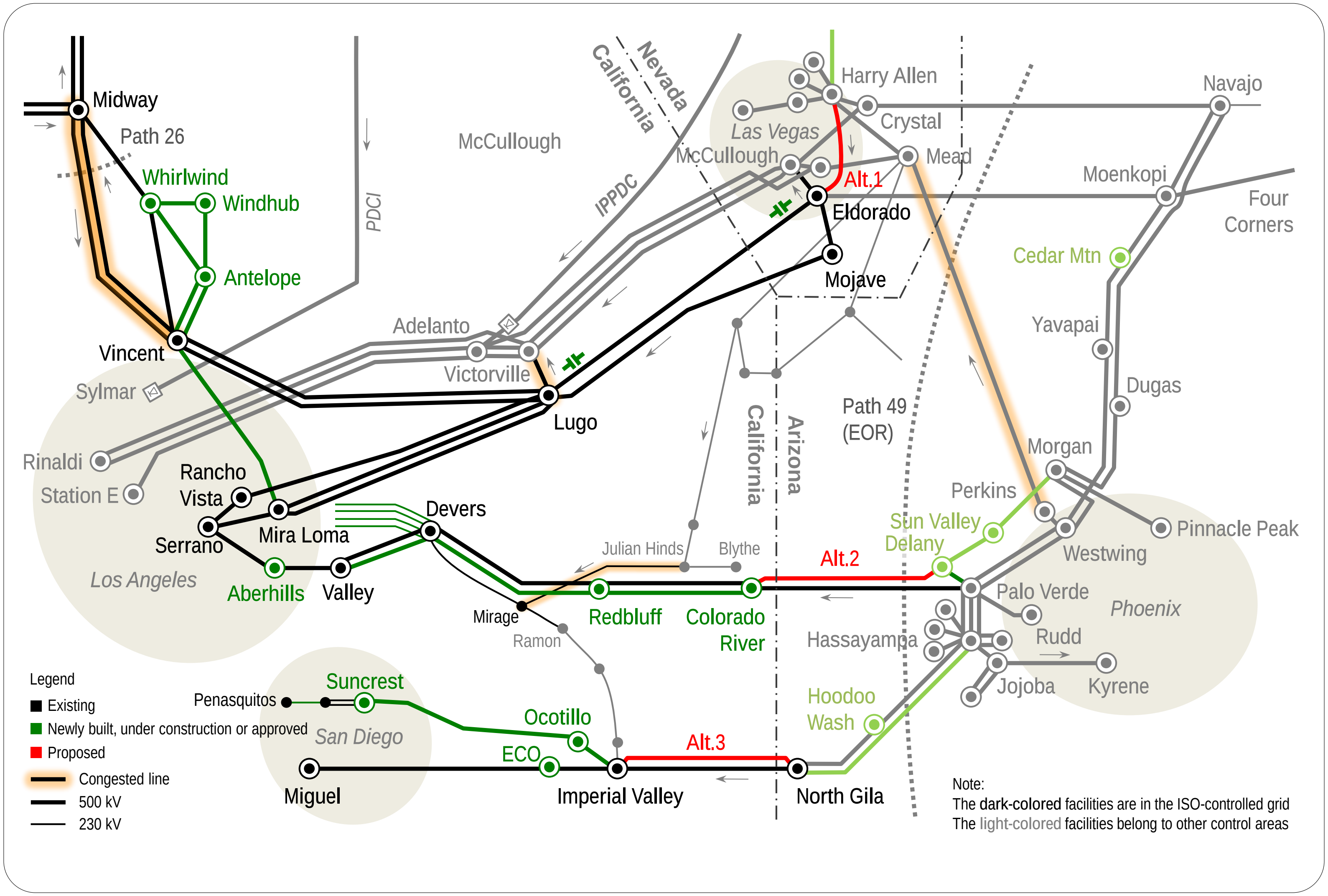
5.7.5.2 Studied network upgrades

This study analyzed the following network upgrades:

1. Harry Allen – Eldorado 500 kV line (from NVE to SCE);
2. Delany – Colorado River 500 kV line (from APS to SCE); and
3. North Gila – Imperial Valley 500 kV line #2 (in SDG&E area).

The first line is in Nevada territory. The second and third lines go from Arizona to California.

Figure 5.7-24: System diagram for the Desert Southwest – California (SWC) area and studied alternatives



5.7.5.3 Congestion analysis

Table 5.7-18 lists the identified congestion in the study area.

Table 5.7-18: Congested facilities in the Desert Southwest – California area

#	Transmission Facilities	Year 2017		Year 2022	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Path 26 (Northern-Southern California) lines	1534	22.519	832	10.456
2	Path 61 (Lugo-Victorville 500 kV line) from SCE to LADWP	-	-	308	1.755
3	Julian Hinds – Mirage 230 kV line	52	0.276	17	0.052
4	Perkins – Mead 500 kV line (not in the ISO-controlled grid)	229	1.682	81	0.953

5.7.5.4 Economic assessment

Table 5.7-19 shows cost estimates for the alternatives of network upgrades.

Table 5.7-19: Cost estimates for the proposed network upgrades in the SWC area

Alt.	Description	Capital Cost	Total Cost
1	Build Harry Allen – Eldorado 500 kV line (~60 miles, NV)	$240M	$348M
2	Build Delany – Colorado River 500 kV line (~110 miles, AZ-CA)	$325M	$471M
3	Build North Gila – Imperial Valley 500 kV line #2 (~80 miles, AZ-CA)	$490M	$711M

The ISO's preliminary analysis was documented in the draft 2012-2013 Transmission Plan released on February 1, 2013, and indicated financial benefits exceeding costs for two of the studied projects in the Desert Southwest – the Delaney-Colorado River 500 kV line and the Harry Allen – Eldorado 500 kV line.

However, in the course of further reviewing those results, the ISO determined that the benefits for at least one of the projects (Delaney-Colorado River) may have been overestimated, primarily due to the treatment of greenhouse gas emissions relating to imports from the Desert Southwest, and that the second project, Eldorado to Harry Allan, requires additional analysis and consideration of alternatives.

The Harry Allen – Eldorado 500 kV line alternative is located in an area that is currently being jointly studied by NV Energy and the ISO for the purpose of investigating the potential for development of transmission facilities between the two systems, as well as sharing conventional and renewable energy resources for the benefit of the respective customer groups. The results of this study could include the Harry Allen – Eldorado 500 kV alternative as well as other possible solutions that should also be considered in the ISO planning process.

5.7.5.5 Recommendation

The ISO therefore recommends:

- One economically-driven 500 kV transmission project, the Delaney-Colorado River transmission project, requires further study and, depending on the results, may be brought forward later this year for Board approval.
- One other economically-driven project, a 500 kV transmission line from Eldorado to Harry Allen, has significant potential benefits, and the ISO will further evaluate it as part of an ongoing joint study with NV Energy and the ISO's general consideration of possible alternatives.

For the Harry Allen – Eldorado 500 kV line, there is an on-going joint study between NV Energy and the ISO. Due to that, the ISO recommends that the proposed line be studied further in subsequent planning cycles with consideration of the joint study results.

For the North Gila – Imperial Valley 500 kV line #2, the ISO intends to do more in-depth studies in future planning cycles, recognizing that while the forecasted benefits do not outweigh the estimated costs, the forecast benefits are material and merit future investigation.

For the Delany – Colorado River 500 kV line, the ISO recommends that the proposed line be approved as an economically-driven network upgrade.

5.7.6 Other issues of congestion

This section discusses a recent congestion issue in the Hoodoo Wash – North Gila area.

The ISO has observed significant market congestion experienced over the 2012 summer on the Hoodoo Wash – North Gila transmission system, which was driven largely by voltage concerns on the underlying WAPA system. The ISO estimates the congestion cost was about $36 million over the July, August and September 2012 period.

The ISO understands that WAPA has approached SDG&E and Arizona Public Service with a proposal to install a capacitor bank (about 45 MVar) at its Kofa substation, with the Bouse substation identified as an alternative location. Further, WAPA has estimated the capital cost of this installation at approximately $4 million, which is to be funded by SDG&E and APS. The anticipated in-service date for the capacitor bank is expected to be in 2013.

The ISO has reviewed the situation and concluded that the congestion costs significantly outweigh the proposed mitigation cost, and that this step can be implemented quickly. Further, the ISO has not been able to identify any lower cost transmission enhancement that would effectively address this congestion in the near term.

The WAPA-proposed mitigation solution does not fit the narrow definition of transmission capital projects that the ISO can approve through its transmission planning process, because the capital project approval process is limited to facilities that will be owned by a participating transmission owner and placed under ISO operational control, yet and the proposed capacitor bank is an upgrade on WAPA's transmission system. Nevertheless, the ISO recognizes that the proposed mitigation is a cost-effective solution to address the congestion concern and has communicated its support for SDG&E's efforts to pursue this upgrade with WAPA.

The ISO also noted that in recent APS transmission plans, a new "Palo Verde Hub – North Gila 500 kV #2 Line" has been proposed and approved. This proposed new line will run in parallel with the existing Hassayampa – Hoodoo Wash – North Gila 500 kV line. According to the *APS 2012-2021 Ten Year Transmission Plan* dated January 2012, the proposed new line is expected to start construction in 2013 and go into service in 2015. This new line is expected to resolve any congestion on the existing Hoodoo Wash – North Gila transmission line in the future.

The ISO modeled this planned new line as Hassayampa – North Gila 500 kV line #2 in the production simulation base cases used during this 2012-2013 planning cycle. Simulations have verified that there will be no congestion on the Hoodoo Wash – North Gila 500 kV line in the 5- and 10-year planning horizon.

5.8 Summary

In this economic planning study, production simulation was conducted for 8,760 hours in each study year for 2017 and 2022; and grid congestion were identified and evaluated. According to the identified areas of congestion concerns, five high-priority studies were conducted and proposed network upgrades were evaluated with economic assessment. The five high-priority studies evaluated eleven network upgrade alternatives for their economic benefits in the following study areas:

1. Path 26 (Northern-Southern California);
2. Los Banos North (LBN);
3. Central California Area (CCA);
4. Pacific Northwest – California (NWC); and
5. Desert Southwest – California (SWC).

In the first four studies, no economic justifications were found for the studied network upgrades. For the congestion analyzed in these four studies, the ISO will continue to monitor the congestion and will conduct further analyses in future studies. In absence of economic justifications and other supports (e.g. policy or reliability needs), the transmission bottlenecks will be handled by congestion management in market operations.

In the fifth study, the ISO's preliminary analysis was documented in the draft 2012-2013 Transmission Plan released on February 1, 2013, and indicated financial benefits exceeding costs for two projects. However, in the course of further reviewing those results, the ISO determined that the benefits for one of the projects (Delaney-Colorado River) may have been overestimated, primarily due to the treatment of greenhouse gas emissions relating to imports from the Desert Southwest, and that the second project, Eldorado to Harry Allan, requires additional analysis and consideration of alternatives. The ISO has therefore concluded:

- One economically-driven 500 kV transmission project, the Delaney-Colorado River transmission project, requires further study and, depending on the results, may be brought forward later this year for Board approval.
- One other economically-driven project, a 500 kV transmission line from Eldorado to Harry Allen, has significant potential benefits, and the ISO will further evaluate it as part of an ongoing joint study with NV Energy and the ISO's general consideration of possible alternatives.

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Chapter 6

6 Other Studies and Results

6.1 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) feasibility studies involve 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 through 2012 CRR annual allocation and auction processes.

6.1.1 Objective

The primary objective of the 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 during the same time horizon.

6.1.2 Data Preparation and Assumptions

The 2012 LT CRR study was performed using the base case network topology used for the annual 2013 (DB58) CRR allocation and auction process. The regional transmission engineers who are responsible for long-term grid planning incorporated all the newly ISO approved transmission projects into the 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 fixed CRR feasibility. The list of projects can be found in the 2011-2012 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 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 is 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 DB58 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.
- The worst case base loading in each market run does not exceed 100 percent of enforced branch rating.
- There are overall improvements on the flow of the monitored transmission elements.

6.1.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the RTE Group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel.
- RTEs model the approved projects and perform the AC power flow analysis to ensure power flow convergence.
- RTEs review all newly approved projects for the transmission planning cycle.
- Consistent with the BPM for Transmission Planning Process section 4.2.2, 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.
- The CRR team reviews the results using user interfaces and displays, in close collaboration with the regional transmission engineering group.
- The input data and results are archived to a secured location as saved cases.

6.1.4 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 planned and the newly approved transmission projects were added to the ISO-controlled grid for the CRR network model. The SFT study also showed general improvement in transmission facility loading after the transmission projects were added.

Chapter 7

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	New 138 Tap: TL13835 Talega to San Mateo-Laguna Niguel (Temporary Tap in-service in 2012, permanent project TBD))	SDG&E	TBD
2	New and/or Upgrade of 69 kV Capacitors	SDG&E	Jun-13
3	New Escondido-Ash 69 kV line TL6956	SDG&E	May-13
4	New Sycamore - Bernardo 69 kV line	SDG&E	Jun-15
5	Reconductor TL663, Mission-Kearny	SDG&E	Jun-15
6	Reconductor TL670, Mission-Clairemont	SDG&E	Jun-15
7	Reconductor TL676, Mission-Mesa Heights	SDG&E	Jun-15
8	Reconductor TL6915, TL6924: Pomerado-Sycamore	SDG&E	Jun-13
9	Removal of Carlton Hills Tap-Sycamore reconfiguration (TL13821B Loop-In)	SDG&E	Dec-13
10	Replace Talega Bank 50	SDG&E	Jun-15
11	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	Jun-14
12	TL631 El Cajon-Los Coches Reconductor	SDG&E	Jun-14

No	Project	PTO Area	Expected In-Service Date
13	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Jun-15
14	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Dec-14
15	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	Jun-14
16	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Jun-16
17	TL6913, Upgrade Pomerado - Poway	SDG&E	2014
18	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	Jun-14
19	Upgrade Los Coches 138/69 kV bank 51	SDG&E	Jun-14
20	Barre - Ellis 230 kV Reconfiguration	SCE	Jun-14
21	Cross Valley Rector Loop Project	SCE	Apr-14
22	Devers-Coachella Valley 230 kV Line Loop	SCE	May-13
23	Devers-Mirage 115 kV System Split	SCE	Jun-13
24	East Kern Wind Resource Area 66 kV Reconfiguration Project	SCE	Jun-14
25	Frazier Park Voltage Support	SCE	Jun-13
26	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-18
27	Johanna & Santiago 230kV Capacitor Banks	SCE	Jul-13
28	Method of Service for Wildlife 230/66 kV Substation.	SCE	Jul-15
29	Method of Service to El Casco 230/115 kV Sub	SCE	Mar-13
30	Path 42 and Devers – Mirage 230 kV Upgrades	SCE	Dec-13
31	Rector Static Var System (SVS) Project (Expand Rector SVS)	SCE	Apr-13
32	Viejo 230kV Capacitor Banks	SCE	Jul-13

No	Project	PTO Area	Expected In-Service Date
33	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	May-17
34	Bay Meadows 115 kV Reconductoring	PG&E	Dec-15
35	Borden 230 kV Voltage Support	PG&E	May-17
36	Caruthers – Kingsburg 70 kV Line Reconductor	PG&E	May-15
37	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	May-17
38	Cayucos 70 kV Shunt Capacitor	PG&E	May-15
39	Clear Lake 60 kV System Reinforcement	PG&E	May-17
40	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	Dec-14
41	Cooley Landing - Los Altos 60 kV Line Reconductor	PG&E	May-16
42	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	May-16
43	Corcoran 115/70 kV Transformer Replacement Project	PG&E	Apr-13
44	Cortina 60 kV Reliability	PG&E	Mar-14
45	Cortina No.3 60 kV Line Reconductoring Project	PG&E	May-16
46	Crazy Horse Switching Station	PG&E	May-15
47	Cressey - North Merced 115 kV Line Addition	PG&E	May-16
48	Del Monte - Fort Ord 60 kV Reinforcement Project	PG&E	Phase 1 – In-Service Phase 2 - May-18
49	East Nicolaus 115 kV Area Reinforcement	PG&E	Oct-14

No	Project	PTO Area	Expected In-Service Date
50	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	May-16
51	Evergreen-Mabury Conversion to 115 kV	PG&E	May-17
52	Fulton 230/115 kV Transformer	PG&E	Dec-16
53	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	May-16
54	Garberville Reactive Support	PG&E	Jun-13
55	Geyser #3 - Cloverdale 115 kV Line Switch Upgrades	PG&E	May-16
56	Glenn #1 60 kV Reconductoring	PG&E	May-15
57	Gold Hill-Horseshoe 115 kV Reinforcement	PG&E	Jun-13
58	Half Moon Bay Reactive Support	PG&E	May-13
59	Helm-Kerman 70 kV Line Reconductor	PG&E	May-16
60	Herndon 230/115 kV Transformer Project	PG&E	May-13
61	Hollister 115 kV Reconductoring	PG&E	Jul-13
62	Humboldt - Eureka 60 kV Line Capacity Increase	PG&E	May-16
63	Humboldt 115/60 kV Transformer Replacements	PG&E	Sep-13
64	Ignacio - Alto 60 kV Line Voltage Conversion	PG&E	May-18
65	Jefferson-Stanford #2 60 kV Line	PG&E	May-17
66	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	May-18
67	Kern - Old River 70 kV Line Reconductor Project	PG&E	May-14
68	Kern PP 115 kV Area Reinforcement	PG&E	May-17
69	Kern PP 230 kV Area Reinforcement	PG&E	May-18

No	Project	PTO Area	Expected In-Service Date
70	Lemoore 70 kV Disconnect Switches Replacement	PG&E	May-15
71	Maple Creek Reactive Support	PG&E	Dec-15
72	Mare Island - Ignacio 115 kV Reconductoring Project	PG&E	May-16
73	Mendocino Coast Reactive Support	PG&E	Dec-14
74	Menlo Area 60 kV System Upgrade	PG&E	May-15
75	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	May-16
76	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-18
77	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	May-18
78	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	May-15
79	Missouri Flat - Gold Hill 115 kV Line	PG&E	Jun-17
80	Monta Vista - Los Altos 60 kV Reconductoring	PG&E	May-18
81	Monta Vista - Los Gatos - Evergreen 60 kV Project	PG&E	May-16
82	Moraga Transformers Capacity Increase	PG&E	Dec-15
83	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Dec-15
84	Moraga-Oakland "J" SPS Project	PG&E	May-16
85	Morro Bay 230/115 kV Transformer Addition Project	PG&E	May-16
86	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	May-18
87	Napa - Tulucay No. 1 60 kV Line Upgrades	PG&E	May-16
88	Navidad Substation Interconnection	PG&E	May-16
89	Newark – Ravenswood 230 kV Line	PG&E	May-15

No	Project	PTO Area	Expected In-Service Date
90	North Tower 115 kV Looping Project	PG&E	May-16
91	Oakhurst/Coarsegold UVLS	PG&E	May-16
92	Oro Loma - Mendota 115 kV Conversion Project	PG&E	May-17
93	Oro Loma 70 kV Area Reinforcement	PG&E	May-18
94	Pease-Marysville #2 60 kV Line	PG&E	Dec-18
95	Pittsburg – Tesla 230 kV Reconductoring	PG&E	Oct-15
96	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-16
97	Pittsburg-Lakewood SPS Project	PG&E	Jul-14
98	Ravenswood - Cooley Landing 115 kV Line Reconductor	PG&E	May-16
99	Reedley 70 kV Reinforcement	PG&E	May-17
100	Reedley-Dinuba 70 kV Line Reconductor	PG&E	May-16
101	Reedley-Orosi 70 kV Line Reconductor	PG&E	May-16
102	Rio Oso - Atlantic 230 kV Line Project	PG&E	May-18
103	Rio Oso Area 230 kV Voltage Support	PG&E	Dec- 17
104	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Dec- 17
105	San Mateo - Bair 60 kV Line Reconductor	PG&E	May-16
106	Santa Cruz 115 kV Reinforcement	PG&E	Dec-15
107	Semitropic - Midway 115 kV Line Reconductor	PG&E	May-17
108	Shepherd Substation	PG&E	May-15
109	Soledad 115/60 kV Transformer Capacity	PG&E	May-18
110	South of San Mateo Capacity Increase	PG&E	Mar-18
111	Stagg – Hammer 60 kV Line	PG&E	May-16

No	Project	PTO Area	Expected In-Service Date
112	Stockton 'A' -Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	Apr-14
113	Table Mountain – Sycamore 115 kV Line	PG&E	May-17
114	Taft 115/70 kV Transformer #2 Replacement	PG&E	May-16
115	Tesla 115 kV Capacity Increase	PG&E	Oct-14
116	Tesla-Newark 230 kV Path Upgrade	PG&E	May-16
117	Tulucay 230/60 kV Transformer No. 1 Capacity Increase	PG&E	May-16
118	Vaca Dixon - Lakeville 230 kV Reconductoring	PG&E	Jun-17
119	Valley Spring 230/60 kV Transmission Addition:	PG&E	Oct-13
120	Vierra 115 kV Looping Project	PG&E	May-16
121	Watsonville Voltage Conversion	PG&E	May-18
122	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	May-14
123	West Coast Recycling - Load Interconnection	PG&E	Mar-14
124	West Point – Valley Springs 60 kV Line	PG&E	May-17
125	West Point - Valley Springs 60 kV Line Project (Second Line)	PG&E	Dec-18
126	Wheeler Ridge 230/70 kV Transformer	PG&E	Apr-13
127	Wheeler Ridge Voltage Support	PG&E	May-16
128	Wilson 115 kV Area Reinforcement	PG&E	May-18
129	Woodward 115 kV Reinforcement	PG&E	Dec-16
130	Imperial Valley Transmission Line Collector Station Project	Undergoing solicitation process	May-15

Table 7.1-2: Status of previously approved projects costing $50M or more

No	Project	PTO Area	Expected In-Service Date
1	Bay Boulevard 230/69 kV Substation Project	SDG&E	Dec-14
2	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	Jun-17
3	Alberhill 500 kV Method of Service	SCE	Jun-14
4	Tehachapi Transmission Project	SCE	2015
5	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	May-18
6	Embarcadero-Potrero 230 kV Transmission Project	PG&E	Dec-15
7	Fresno Reliability Transmission Projects	PG&E	May-15
8	New Bridgeville - Garberville No.2 115 kV Line	PG&E	Dec-18
9	Palermo – Rio Oso 115 kV Line Reconductoring	PG&E	Dec-13
10	South of Palermo 115 kV Reinforcement Project	PG&E	May-17
11	Vaca – Davis Voltage Conversion Project	PG&E	May-18

7.2 Transmission Projects found to be needed in the 2012-2013 Planning Cycle

In the 2012-2013 transmission planning process, the ISO determined that 36 transmission projects were needed to mitigate identified reliability concerns and 5 policy-driven projects were needed to meet the 33 percent RPS. The summary of these transmission projects are in the tables below.

A list of projects that came through the 2012 Request Window can be found in Appendix F.

Table 7.2-1: New reliability projects found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Talega Area Dynamic Reactive Support	San Diego Area	6/1/2018	$58-72M
2	Sweetwater Reliability Enhancement	San Diego Area	6/1/2017	$10-12M
3	TL13820, Sycamore-Chicarita Reconductor	San Diego Area	6/1/2014	$0.5 - 1M
4	TL674A Loop-in (Del Mar - North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	San Diego Area	6/1/2015	$12-15M
5	South Orange County Dynamic Reactive Support	SCE Area	6/1/2014	$50-75M
6	Almaden 60 kV Shunt Capacitor	Greater Bay Area	5/31/2015	$5-10M
7	Arco #2 230/70 kV Transformer	Greater Fresno Area	12/31/2013	$15-19M
8	Atlantic-Placer 115 kV Line	Central Valley Area	5/31/2017	$55-85M
9	Christie 115/60 kV Transformer No. 2	Greater Bay Area	12/31/2014	$12-17M
10	Contra Costa Sub 230 kV Switch Replacement	Greater Bay Area	5/31/2015	< $1M

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
11	Cressey - Gallo 115 kV Line	Greater Fresno Area	12/31/2013	$15-20M
12	Diablo Canyon Voltage Support Project	Central Coast and Los Padres	5/31/2016	$35-45M
13	Gates #2 500/230 kV Transformer Addition	Central California /Fresno Area	2017	$75-85M
14	Gates-Gregg 230 kV Line	Central California /Fresno Area	2022	$115-145M
15	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	Greater Fresno Area	5/31/2015	$1-2M
16	Kearney #2 230/70 kV Transformer	Greater Fresno Area	12/31/2015	$32-37M
17	Kearney-Caruthers 70 kV Line Reconductor	Greater Fresno Area	5/31/2016	$13-20M
18	Kearney - Hearndon 230 kV Line Reconductoring	Central California /Fresno Area	2017	$15-25M
19	Lockheed No.1 115 kV Tap Reconductor	Greater Bay Area	5/31/2016	$2-3M
20	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	Greater Fresno Area	5/31/2015	$0.5-1M
21	Los Esteros-Montague 115 kV Substation Equipment Upgrade	Greater Bay Area	5/31/2016	$0.5-1M
22	Midway-Temblor 115 kV Line Reconductor and Voltage Support	Kern Area	5/31/2018	$25-35M
23	Monte Vista 230 kV Bus Upgrade	Greater Bay Area	5/31/2016	$10-15M

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
24	Monta Vista-Wolfe 115 kV Substation Equipment Upgrade	Greater Bay Area	5/13/2015	$0.5-1M
25	Midway-Andrew 230 kV Project	Central Coast and Los Padres	12/31/2019	$120-150M
26	Newark-Applied Materials 115 kV Substation Equipment Upgrade Project	Greater Bay Area	5/31/2016	$0.5-1M
27	Northern Fresno 115 kV Reinforcement	Greater Fresno Area	5/1/2018	$110-190M
28	NRS-Scott No. 1 115 kV Line Reconductor	Greater Bay Area	5/31/2016	$2-4M
29	Pease 115/60 kV Transformer Addition and Bus Upgrade	Central Valley Area	5/31/2016	$25-35M
30	Lockeford-Lodi Area 230 kV Development	Central Valley Area	5/31/2017	$80-105M
31	Potrero 115 kV Bus Upgrade	Greater Bay Area	5/31/2017	$10-15M
32	Ripon 115 kV Line	Central Valley Area	5/31/2015	$10-15M
33	Salado 115/60 kV Transformer Addition	Central Valley Area	12/31/2014	$15-20M
34	Series Reactor on Warnerville-Wilson 230 kV Line	Central California /Fresno Area	2017	$20-30M
35	Stone 115 kV Back-tie Reconductor	Greater Bay Area	5/31/2016	$3-6M
36	Trans Bay Cable Dead Bus Energization Project	Greater Bay Area	11/30/2014	$20-30M

Table 7.2-2: New policy-driven transmission projects found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Sycamore – Penasquitos 230kV Line	San Diego Area	6/1/2017	$111-221M
2	Lugo – Eldorado 500 kV Line Re-route	SCE Area	2020	$36M
3	Lugo – Eldorado series cap and terminal equipment upgrade	SCE Area	2016	$121M
4	Warnerville-Bellota 230 kV line reconductoring	PG&E Area	2017	$28M
5	Wilson-Le Grand 115 kV line reconductoring	PG&E Area	2020	$15M

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 economically-driven transmission elements, as well as for reliability-driven elements that provide additional policy and economic benefits. Where the ISO selects a transmission solution to meet an identified need in one of the three aforementioned categories that constitutes an upgrade to or addition 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, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner..

As described previously in this transmission plan, the ISO is not recommending for approval at this time any economically-driven transmission projects. As set out in chapter 4, the ISO has identified the following new policy-driven projects in the 2012-2013 transmission plan:

- Lugo-Eldorado 500 kV line re-route
- Lugo-Eldorado series capacitor and terminal equipment upgrade
- Warnerville-Bellota 230 kV line reconductoring
- Wilson-Le Grand 115 kV line reconductoring
- Sycamore-Penasquitos 230 kV transmission line

Because there can be viable alternatives for a Sycamore-Penasquitos line that do not necessitate the use of existing right of way for the entirety of the transmission element, this transmission element does not therefore 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 and, as such, this element is eligible for competitive solicitation.

The ISO undertook a review of the individual elements comprising the other reliability-driven projects identified in the 2012/2013 Transmission Plan. 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.

The following reliability project elements were reviewed for potential incidental economic or public policy benefits.

a. Gregg-Gates 230 kV transmission line
b. Lockford-Lodi Area 230 kV development
c. Altantic Placer 115 kV transmission line
d. Rippon 115 kV transmission line
e. Midway-Andrew 230 kV project
f. North Fresno 115 kV upgrade

g. Cressey-Gallo 115 kV transmission line

h. South Orange County Dynamic Reactive Support

i. Talega area Dynamic Reactive Support

j. Diablo Canyon Voltage Support Project

These elements were then evaluated for:

1. Additional policy benefits, which are demonstrated if a reliability project is also needed under Section 24.4.6.6 or eliminates or partially fills the need for a policy-driven transmission element found to be needed under that section.
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 percent of the cost of the project.

The ISO has determined that the Gregg-Gates 230 kV transmission line, which is a needed reliability project, also provides incidental public policy benefits, in accordance with the tariff. The ISO also performed an economic analysis of this project as well as an economic analysis of elements (b) through (g), as set out above. The ISO determined that the three dynamic reactive support projects identified as elements (h) through (j) do not meet the incidental economic benefits standard under the tariff because these elements are expected to operate at or near zero output on a daily basis in order to be properly positioned and are ready to assist in the event of unplanned contingencies. As such, they are not expected to provide economic benefits beyond the reliability functions they serve.

Table 7.3-1: Assessment of Additional Economic Benefits Provided by Reliability-Driven Projects

No.	Project	Capital Cost $ millions	Total Cost (1)	Congestion Benefit	Year 1 Loss Saving MWh	Loss Savings $ Millions (2)	Cost Benefit Ratio (3)
1	Lockeford-Lodi Area 230 kV Development	$80 - 105	$116 – 152	0	12,557	$11.71	8.7%
2	Atlantic Placer 115 kV Line	$55 - 85	$80 – 123	0	3,000	$2.63	2.6%
3	Rippon 115 kV Line	$10 - 15	$15 – 22	0	841	$0.78	4.3%
4	Midway-Andrew 230 kV Project	$120 - $150	$174 - 217.5	0	20,140.33	$18.78	9.6%
5	Cressey-Gallo 115kV	$15 - 20	$22 - 29	0	399	$0.32	1.27%
6	North Fresno 115kV Reinforcement	$110 - 190	$160 - 275	0	23,654	$19.12	8.79%
7	New Gates-Gregg 230 kV line	$115 - 145	$167 - 210	0	113,816	$103.73	55%

Notes: 1 RR/CC ratio of 1.45 consistent with Section 5
2 Losses are valued at $58.05/MWh
3 Cost benefit ratio is based upon average Total Cost.

In the above analysis, the “total cost” was based on the present value of the annualized revenue requirement estimated for the project’s capital cost. Consistent with the methodology set out in chapter 5, a ratio of 1.45:1 was applied. Transmission line losses were valued at $58.05/MWh, and the cost/benefit ratio was based upon average total cost.

Based on the review conducted by the ISO, we have identified two reliability-driven elements eligible for competitive solicitation in this transmission plan because of their additional benefits:

- Sycamore – Penasquitos 230kV Line ($111 - 211 million)
- Gates-Gregg 230 kV Line ($115 - 145 million)

Also, the Delaney – Colorado River project, which as previously discussed, is being further reviewed, would be eligible for competitive solicitation if it is recommended for inclusion in the transmission plan later this year and approved by the Board. Some of the other areas identified for further study could also trigger additional needs that if approved by the Board could be eligible for competitive solicitation.

7.4 Capital Program Impacts on Transmission High Voltage Access Charge

7.4.1 Background

The ISO has developed an internal tool to estimate future trends in the High Voltage Transmission Access Charge (HV TAC) to provide an estimation of the impact of the capital projects identified in the 10 Year Transmission Plan on the access charge.

The final and actual determination of the High Voltage Transmission Access Charge is the result of numerous and extremely complex revenue requirement and cost allocation exercises conducted by the ISO's participating transmission owners, with the costs being subject to FERC regulatory approval before being factored in the determination of a specific HV TAC rate recovered by the ISO from ISO customers. In seeking to provide estimates of the impacts on future access rates, we recognized it was neither helpful nor efficient to attempt to duplicate that modeling in all its detail. Rather, an excessive layer of complexity in the model would make a high level understanding of the relative impacts of different cost drivers more difficult to review and understand. However, the cost components need to be considered in sufficient detail that the relative impacts of different decisions can be reasonably estimated.

The ISO therefore developed a high level rate impact model that is based on the fundamental cost-of-service models employed by the participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and so forth. Cost calculations included costs associated with existing rate base and operating expenses, and, for new capital costs, tax, return, depreciation, and an operations and maintenance (O&M) component.

The model is not a detailed calculation of any individual participating transmission owner's revenue requirement – parties interested in that information should contact the specific participating transmission owner directly. For example, certain PTOs' existing rate bases were slightly adjusted to "true up" with a single rate of return and tax treatment to the actual initial revenue requirement incorporated into the TAC rate, recognizing that individual capital facilities are not subject to the identical return and tax treatment. This "true up" also accounts for construction funds already spent which the utility has received FERC approval to earn return and interest expense upon prior to the subject facilities being completed.

Stakeholders have suggested that breaking out rate impacts by category, e.g. reliability-driven, policy-driven and economically-driven categories used by the ISO to develop the comprehensive plan in its structured analysis, or by utility. The ISO is concerned that a breakout by ISO category can create industry confusion, as, for example, a "policy-driven" project may have also addressed the need met by a previously identified reliability-driven project. While the categorization is appropriately as a "policy-driven" project for transmission planning tariff purposes, it can lead to misunderstandings of the cost implications of achieving certain policies – as the entire replacement project is attributed to "policy". Further, certain high level assumptions are appropriate on an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility. Therefore, before it would be appropriate to communicate cost impacts on a more granular basis, further analysis will need to be considered.

7.4.2 Input Assumptions and Analysis

The ISO's rate impact model is based on publicly available information or ISO assumptions as set out below, with clarifications provided by several utilities.

Each PTO's most recent FERC revenue requirement approvals were relied upon for revenue requirement consisting of capital related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO were utilized, which necessitated some adjustments to rate base. These adjustments were "back-calculated" such that each PTO's total revenue requirement aligned with the filing.

Total existing costs were then adjusted on a going forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts.

Escalation of O&M costs and capital maintenance were applied on a single basis based on North American industry-wide experience – these have not yet been adjusted to reflect possible local variations from more industry-wide estimated parameters. A 2% escalation of O&M costs was used, and capital maintenance of 2% of gross plant was applied. While these are not precise, and the ISO will seek refinements to the model in future periods, these approximations were considered reasonable to determine a base upon which to assess the impact of the ISO's capital program on the HV TAC.

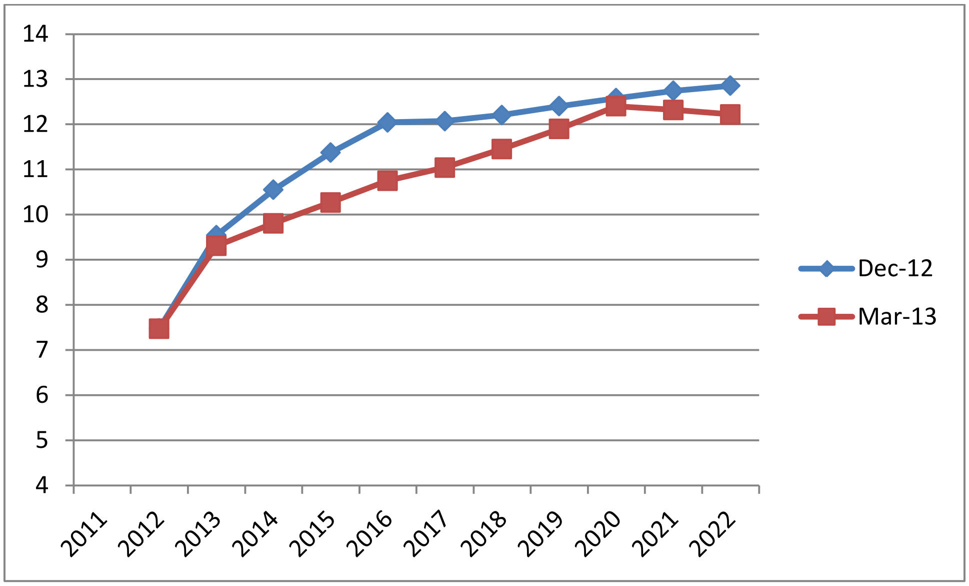
All reliability-driven projects were summed into a single project for data entry into the model, and all major policy and economic projects were modeled as individual projects. The model accommodates project-specific tax, return, depreciation and Allowances for Funds Used During Construction (AFUDC) treatment information.

In modeling individual projects, it is important to note that some projects have been awarded unique treatment, such as inclusion of Capital Work in Progress (CWIP) in rate base. For certain projects under construction, therefore, the existing high voltage TAC rate already reflects a major portion of the project cost, rather than the impact only being seen upon commissioning of those facilities. For those projects, the capital costs attributed to the "project" entry were for costs that remained to be spent, as the adjusted existing rate base and existing revenue requirement already reflect the costs that have been incurred and are included in rates.

A major component of the TAC calculation is the load forecast as the transmission revenue requirement is divided by the load to determine the rate. The ISO forecasts 1% annual load growth over the same period, which is consistent with CEC projections and historical trends.

Based on the above inputs and assumptions, the ISO has projected the impacts of the capital projects identified in this plan in Figure 7.4-1 below.

Figure 7.4-1: Forecast of Capital Project Impact on ISO High Voltage Transmission Access Charge



By way of comparison, the above figure also provides the impact estimated at the time of the December 2012 update to the ISO Board of Governors. The changes predominantly reflect new information about capital programs, and additional clarity from PTOs regarding CWIP already reflected in existing rates.