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California ISO

# 2017-2018
## TRANSMISSION PLAN

March 22, 2018

Board Approved

**Foreward to Board-Approved 2017-2018 Transmission Plan**

At the March 22, 2018 ISO Board of Governors meeting, the ISO Board of Governors approved the 2017-2018 Transmission Plan.

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# Executive Summary

The California Independent System Operator Corporation's 2017-2018 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals, and explore projects that can bring economic benefits to consumers. This plan is updated annually, and culminates in an ISO Board of Governors (Board) approved transmission plan that identifies the needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval, as well as identifying non-transmission solutions that will be pursued in other venues as an alternative to building additional transmission facilities. It is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

The transmission plan is developed through a comprehensive stakeholder process and also relies heavily on coordination with key energy state agencies – the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) – for key inputs and assumptions regarding electricity demand side forecast assumptions as well as supply side potential.

The aggressive pace of the electric power industry transformation in California continues to set the context for the ISO's annual transmission plan, where the focus is recalibrated each year to reflect the status of a range of issues at that time. This year's transmission plan continues to reflect those changing circumstances and the specific needs emerging at this particular point in time. Key trends in this year's transmission plan include the following:

- The progress made through past transmission plans to address reliability issues overall and planning for the retirement of once-through-cooling generation – including the San Onofre Nuclear Generating Station – continue to result in relatively modest transmission reinforcement needs. Despite relatively flat load forecast growth over the planning period, new reliability challenges have emerged driving the need for system reinforcements on a case-by-case basis, however;
- Consistently declining load forecasts across the entire forecast period – especially for the one-in-ten peak load forecasts affected by weather normalization processes – has led to the third year of re-evaluation of previously-approved upgrades. This year's re-evaluation effort has been the most comprehensive to date, and also entailed not just reviewing and canceling previously-approved projects, but also re-scoping projects to more effectively and efficiently meet needs. The downward pressure on peak demand load growth and energy consumption was compounded by higher than anticipated development of behind-the-meter solar photovoltaic generation. Behind-the-meter solar has reduced the summer peak loads traditionally occurring in mid-day in many parts of the state and shifted them towards the unaffected load levels occurring later in the day when solar production has dropped off;
- Sustained emphasis on minimizing environmental impacts of the electricity industry and reducing greenhouse gas emissions continue to drive more integrated solutions to emerging

needs that rely on combinations of preferred and conventional resources, as well as transmission;

- Transmission needed to access renewable generation development to achieve the state's 33 percent RPS goal by 2020 and sustain it over the planning horizon have largely been identified and are moving forward. New policy driven in-state and interregional transmission planning to achieve the state's 50 percent RPS goal by 2030[1] will not be actionable until policy direction is set to choose among technologically and geographically diverse renewable resources. This is anticipated to occur through the CPUC's Integrated Resource Plan processes;
- The recent need in 2017 for the ISO to enter into new backstop procurement arrangements for reliability must-run contracts as well as for annual capacity procurement mechanism designations (the latter being employed for the first time since the mechanisms were put in place) has triggered a renewed focus on assessing the reliance on gas-fired generation to meet system flexible needs as well as local capacity needs in the face of economic pressure on the existing gas-fired generation fleet; and,
- Changing economic and industry conditions are creating new opportunities for economic-driven transmission projects, which have led to several more modestly sized projects being identified in this year's plan. The evolution of the policy landscape and shifting economic and environmental considerations may lead to further opportunities in the future.

Overall, the 2017-2018 Transmission Plan includes a modest increase in new reliability and economic needs, a major downsizing of previously-approved projects addressing the "backlog" that accumulated during periods of higher forecast rates of load growth, and an expanded reliance on hybrid solutions incorporating conventional transmission and preferred resources. The ISO's efforts to increase opportunity for non-transmission alternatives, particularly preferred resources and storage, continues to be a key focus of the transmission planning analysis both in developing supportive tools and methodologies and in the assessment of these resources on their own or in conjunction with transmission upgrades to meet grid needs.

Our comprehensive evaluation of the areas listed above resulted in the following key findings:

- The ISO identified 13 transmission projects with an estimated cost of approximately $182.3 million as needed to maintain transmission system reliability. Several of these projects also entail a combination of preferred resource procurement and transmission upgrades working together to meet those needs;
- In this third year of a comprehensive review of previously-approved projects in the PG&E service territory, the ISO built on study efforts in previous cycles and not only identified projects that were no longer needed, but also explored re-scoping a significant number of projects to better reflect evolving needs. As a result of the review, 18 projects are recommended to be canceled, and major scope changes have been identified for 21 other

[1] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. The new law establishes targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030. Future planning cycles will focus on moving beyond the 33 percent framework when renewable generation portfolios become available through the process established with the California Public Utilities Commission and California Energy Commission.

projects, paring over $2.6 billion from the ISO transmission capital program estimated costs. Seven other projects will continue to be on hold pending reassessment in future cycles.

- Two previously-approved projects in the SDG&E area have also been identified as no longer needed. One was physically impacted by a CPUC siting decision regarding a project in the same area, and one by evolving demand forecasts.
- The ISO's analysis indicated in this planning cycle that the authorized resources, forecast load, and previously-approved transmission projects working together continue to meet the forecast reliability needs in the LA Basin and San Diego areas. However, due to the inherent uncertainty in the significant volume of preferred resources and other conventional mitigations, the situation is being continually monitored in case additional measures are needed;
- Consistent with recent transmission plans, no new major transmission projects have been identified at this time to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the CPUC approval process;
- Four economic-driven transmission projects totaling an estimated capital cost of $89 million are recommended for approval, providing benefits ranging from energy costs savings to reductions in local capacity requirements;
- The ISO tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan. None of the transmission projects in this transmission plan include facilities eligible for competitive solicitation through the ISO's competitive solicitation process.
- Progress also continued in the 2017-2018 Transmission Plan in exploring potentially critical issues emerging as the generation fleet continues its transformation towards greenhouse gas reductions. The ISO's informational special studies undertaken in the planning process help supplement the forward thinking on these issues triggered by the tariff-based planning process. In this transmission planning cycle, a number of special studies continued the efforts of past studies, and either drew that work to completion or are being incorporated into other ongoing work streams or initiatives.

As noted above, the transmission plan is based on the ISO's transmission planning process, which involved collaborating with the CPUC, the CEC 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

The transmission plan primarily identifies three main categories of transmission solutions: reliability, public policy and economic needs. The plan may also include transmission solutions 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 also considers and places a great deal of emphasis on the development of non-transmission alternatives, both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage 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. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the ISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The transmission planning process is defined by three distinct phases of activity that are completed in consecutive order across a time frame called a planning cycle. The planning cycle begins in January of each year, with the development of the study plan – phase 1. Phase 2, which includes the technical analysis, selection of solutions and development of the transmission plan for approval by the ISO Board of Governors, extends beyond a single year and concludes in March of the following year. If Phase 3 is required, engagement in a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan, it takes place after the March approval of the plan. This results in the initial development of the study plan and assumptions for one cycle to be well underway before the preceding cycle has concluded, and each transmission plan being referred to by both the year it commenced and the year it concluded. The 2016-2017 planning cycle, for example, began in January 2016 and the 2016-2017 Transmission Plan was approved in March 2017.

## Planning Assumptions and State Agency Coordination

The 2017-2018 planning assumptions and scenarios were developed through the annual agency coordination process the ISO, CEC and CPUC have in place and performed each year to be used in infrastructure planning activities in the coming year. This alignment effort continues to improve infrastructure planning coordination within the three core processes:

- Long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- Biennial integrated resource plan proceedings (IRP) and long term procurement plan proceedings (LTPP) conducted by the CPUC, and
- Annual transmission planning processes performed by the ISO.

In this coordination effort, the agencies considered assumptions such as demand, supply and system infrastructure elements, and the 33 percent RPS generation portfolios proposed by the CPUC. The results of the CPUC's annual process feeding into this 2017-2018 transmission planning process were communicated via an assigned commissioner's ruling in the CPUC's

Integrated Resource Plan Process.[2] These assumptions were further vetted by stakeholders through the ISO's stakeholder process which resulted in this year's study plan.[3]

The ISO's policy driven transmission framework enables the ISO to identify and approve transmission facilities that system users will need to comply with state and federal requirements or directives. The primary policy directive for past planning cycles and the current cycle is the achievement of California's renewables portfolio standard.

California's Clean Energy and Pollution Reduction Act of 2015, SB 350, was signed into law on October 7, 2015 establishing targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030, moving beyond the earlier requirement of that called for a 33 percent target by 2020. While policy direction is expected to be developed in the future to move beyond 33 percent through the CPUC's IRP proceedings, this direction is not yet available. Consequently, the CPUC advised the ISO to continue to re-use the "33% 2025 Mid AAEE" RPS portfolio in the 2017-18 TPP studies as the base case renewable resource portfolio that was used in the 2015-16 TPP and 2016-17 studies.

The ISO considers the agencies' successful effort coordinating the development of the common planning assumptions to be a key factor in promoting the ISO's transmission plan as a valuable resource in identifying grid expansion necessary to maintain reliability, lower costs or meet future infrastructure needs based on public policies.

## Key Reliability Study Findings

During the 2017-2018 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards and ISO planning standards and tariff requirements. The analysis was performed across a 10-year planning horizon and modeled a range of on-peak and off-peak system conditions. The ISO's assessment considered facilities across voltages of 60 kV to 500 kV, and where reliability concerns existed, the ISO identified transmission solutions to address these concerns. This plan proposes approving 13 reliability-driven transmission projects, representing an investment of approximately $182.3 million in infrastructure additions to the ISO controlled grid.

[2] The "Draft 2017 Assumptions and Scenario for Long Term Planning" is included as an attachment to Administrative Law Judge Julie A. Fitch's ruling seeking comment, issued in CPUC Proceeding No. R.16-02-007, January 18, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF.

[3] The 2017-2018 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 31, 2017, is available at: http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf

Table 1 – Summary of Needed Reliability-Driven Transmission Projects in the ISO 2017-2018 Transmission Plan

| Service Territory | Number of Projects | Cost (in millions) |
|---|---|---|
| Pacific Gas & Electric (PG&E) | 9 | $117.3 |
| Southern California Edison Co. (SCE) | 1 | $45 |
| San Diego Gas & Electric Co. (SDG&E) | 2 | $9 |
| Valley Electric Association (VEA) | 0 | 0 |
| Across SCE, PG&E, and VEA | 1 | 11 |
| Total | 13 | $182.3 |

These projects are not eligible for the ISO's competitive solicitation process.

In addition to the identification of new reliability requirements, the ISO also completed the third year of a three-year review of a range of previously-approved transmission projects. This third and most comprehensive year of review looked not only at canceling projects where changing circumstances no longer supported the need for the project, but re-scoping of projects where needs still existed and changing circumstances could lead to more effective and economic solutions.

In reviewing the continued need for those projects – that were predominantly load forecast driven and whose approvals dated back a number of years – in light of materially lower load forecast levels since those projects were approved, the ISO took into account existing planning standards, California local capacity requirements, and deliverability requirements for generators with executed interconnection agreements. As a result of the review, the following changes pare over $2.6 billion from the ISO transmission capital program:

- 18 predominantly lower-voltage transmission projects that were found to be no longer required and are recommended to be canceled.
- Two projects were found not to be needed for meeting reliability standards, but provide reliability benefits outweighing costs and will proceed.
- Major scope changes and downsizing of 21 projects have been identified.
- Seven projects will continue to be on hold pending reassessment in future cycles.

Two previously-approved projects in the SDG&E area have also been identified as no longer needed. One was impacted by the siting decision of the CPUC in approving SDG&E's application for a certificate of public convenience and necessity (CPCN) for the Sycamore-Penasquitos project, and one by evolving demand forecasts.

The ISO is pleased to have this comprehensive review completed, and while individual projects will continue to be considered on a case by case basis, this type of comprehensive review is not anticipated to be needed in future planning cycles.

## Renewables Portfolio Standard Policy-driven Transmission Assessment

As noted above, the CPUC and CEC recommended that the ISO re-use the "33% 2025 Mid AAEE" RPS portfolio used in the 2015-2016 TPP and 2016-017 studies, as the base case renewable resource portfolio in the 2017-2018 TPP studies.

As the deliverability impacts of these portfolios were already studied in the 2015-2016 and 2016-2017 transmission planning cycles, the ISO determined that no additional policy-driven analysis was needed.

Given the previous study results and the state agencies' objective of avoiding triggering new reinforcement additions until 50 percent renewable portfolio standard generation portfolios are available, the ISO is not recommending any new transmission solutions at this time for policy purposes.

A summary of the various transmission elements already underway for supporting California's renewables portfolio standard is shown in Table 1. 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 major transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the permit approval process; and
- Major transmission projects that have been previously approved by the ISO but are not yet permitted.

Table 1: Elements of 2017-2018 ISO Transmission Plan Supporting 33% Renewable Energy Goals

| Transmission Facility | Online |
|---|---|
| Transmission Facilities Approved, Permitted and Under Construction | |
| West of Devers Reconductoring | 2021 |
| Sycamore – Penasquitos 230 kV Line | 2018 |
| Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap | Completed January 2018 |
| Additional Major Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted | |
| None at this time | |
| Policy-Driven Transmission Elements Approved but not Permitted | |
| Lugo – Eldorado series cap and terminal equipment upgrade | 2020 |
| Warnerville-Bellota 230 kV line reconductoring | 2022 |
| Wilson-Le Grand 115 kV line reconductoring | 2020 |
| Suncrest 300 Mvar SVC | 2017[4] |
| Lugo-Mohave series capacitors | 2020 |
| Additional Policy-Driven Transmission Elements Recommend for Approval | |
| None identified in 2017-2018 Transmission Plan | |

## Key Economic Study Findings

The ISO's economic planning study is an integral part of the ISO's transmission planning process and complements the reliability-driven and policy-driven analysis by exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO. The studies used a production cost simulation as the primary tool to identify potential economic development opportunities and in assessing those opportunities. While reliability analysis provides essential information about the electrical characteristics and performance of the ISO controlled grid, an economic analysis provides essential information about transmission congestion which is a key input in identifying potential study areas, prioritizing study efforts, and assessing benefits by identifying grid congestion and assessing economic benefits created by

[4] In service date to be revisited by project sponsor now that the Environmental Impact Report has been completed.

congestion mitigation measures. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load, and minimizing or resolving transmission congestion can be cost effective to the ratepayer if solutions can be implemented to generate savings that are greater than the cost of the solution. Other end-use ratepayer cost saving benefits such as reducing local capacity requirements in transmission-constrained areas can also provide material benefits. Note that other benefits and risks – which cannot always be quantified – must also be taken into account in the ultimate decision to proceed with an economic-driven project.

An economic planning analysis was performed as part of the 2017-2018 transmission planning cycle in accordance with the unified planning assumptions and study plan. All approved reliability and policy network upgrades and those recommended for approval in this plan were modeled in the economic planning database. This ensured that the results of the analysis would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan.

The first step in the economic planning analysis was to perform production simulation identifying potential areas of congestion on the transmission system. This was used to identify priority study areas, to prioritize the eight stakeholder study requests received in this planning cycle, and to provide cost savings benefits information into the more detailed analysis. Further production simulation analysis of congestion mitigation alternatives also informs project selection decisions. Other potential opportunities for benefits were also explored, including reducing local capacity requirements in particular. As a result, four areas were selected for further detailed study, and three of these led to the identification of four economic-driven transmission projects that were found to be needed.

In summary, four projects were found to be needed as economic-driven projects in the 2017-2018 planning cycle:

- The S-Line Upgrade – rebuilding the approximately 18 mile wood pole 230 kV single circuit owned by the Imperial Irrigation District to double circuit steel tower construction, to alleviate parallel flow issues and reduce local capacity requirements and provide production simulation energy benefits.
- The Bob SS to Mead S 230 kV Line Upgrade – rebuilding the line in Nevada from the planned Bob switching station to the Mead substation to alleviate transmission congestion.
- The San Jose-Trimble 115 kV Series Reactor - part of the South Bay-Moss Landing enhancements to reduce local capacity requirements in the South Bay-Moss Landing sub-area.
- The Moss Landing–Panoche 230 kV Path Upgrade - part of the South Bay-Moss Landing enhancements to reduce local capacity requirements in the South Bay-Moss Landing sub-area.

Several paths and related projects will be monitored in future planning cycles to take into account improved hydro modeling, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals.

## Non-Transmission Alternatives and Preferred Resources

The ISO has routinely emphasized exploring preferred resources[5] and other non-transmission alternatives to conventional transmission to meet emerging reliability needs. Through area-specific studies[6] and continued efforts to refine understanding of the necessary characteristics for slow response demand response to provide local capacity[7], the ISO's applications have expanded in this planning cycle beyond the ISO's original methodology[8] set in place some years ago.

While preferred resources are already relied upon in a number of areas in the ISO footprint, this year's transmission planning activities are recommending several integrated solutions, with baskets of preferred resources and economical and low impact conventional transmission upgrades working together to meet local reliability needs, which are particularly noteworthy:

- Moorpark and Santa Clara Sub-area local capacity requirements: The ISO is recommending the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers as part of a more multi-faceted solution to meeting local area needs that will include preferred resources being procured by Southern California Edison. This plan will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling. (see section 2.7.5.4)
- Oakland area needs without local generation: The ISO is recommending the Oakland Clean Energy Initiative to address East Bay area needs while planning for future operation without reliance on local gas-fired generation. The project is a combination of substation upgrade projects and preferred resources. (see section 2.5.5.4)

## Informational Studies

An aggressive number of special studies had been undertaken in the 2016-2017 planning process to help inform future planning efforts and enhance the understanding of certain emerging issues. A number were extended into the 2017-2018 planning cycle to enable further consideration of findings raised in the 2016-2017 process. These included the following:

[5] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

[6] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

[7] See section 6.6 of this 2017-2018 Transmission Plan

[8] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

- Updating previous "information only" studies regarding the potential impact of moving to 50 percent Renewables Portfolio Standard under various scenarios, providing further assessments of the transmission system's ability to import out-of-state renewable generation, and assessment of the potential benefits of various interregional transmission planning projects submitted into the first biennial interregional coordination process established by the ISO and the ISO's neighboring planning regions in response to FERC Order No. 1000;
- Further analysis of the benefits of large energy storage in managing oversupply periods in a 50 percent renewables portfolio standard condition studied in the 2016-2017 planning cycle; this study explored additional sensitivities to test study assumptions;
- Updating the review of the risks to system reliability of existing gas-fired generation retirements triggered by a response to economic conditions studied in the 2016-2017 planning cycle, focusing on the overall supply perspective;
- Supporting the efforts regarding gas pipeline and electricity coordination with a focus on the Aliso Canyon concerns and CPUC proceeding;
- Continuing frequency response study efforts by improved modeling of generation – building on the results of the frequency response analysis conducted in last year's cycle and the observed gap between actual measured performance and study results.
- Finalizing the methodology and developing initial results for the necessary characteristics for slow response resources in local capacity areas to be relied upon for local resource adequacy capacity.

The additional informational "special" studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

## Conclusions and Recommendations

The 2017-2018 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, address grid reliability requirements and bring economic benefits to consumers.  This year's plan identified 17 transmission projects, estimated to cost a total of approximately $271.3 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 ISO has also identified 20 previously-approved transmission projects that are recommended to be canceled, 21 that needed major scope revisions, and seven that require further evaluation in future year's planning cycles before applications proceed for construction permitting. The ISO has also identified that further analyis is needed to finalize its recommendation on one additional project, which the ISO is seeking to complete in this planning cycle.

The additional informational studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

# Chapter 1

# 1 Overview of the Transmission Planning Process

## 1.1 Purpose

A core ISO responsibility is to identify and plan the development of solutions to meet the future needs of the ISO controlled grid. Fulfilling this responsibility includes conducting an annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved, comprehensive transmission plan. The plan identifies needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval. The plan also identifies non-transmission solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. This document serves as the comprehensive transmission plan for the 2017-2018 planning cycle.

As in recent transmission planning cycles, the ISO has prepared this plan in the larger context of supporting important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. That future is not only being planned on the basis of transitioning to lower emission sources of electricity, but on evolving forecasts and expectations being set for transitions in how and when electricity is used. While each year's transmission plan is based on the best available forecast information at the time the plan is prepared, the ISO has also had to consider and adapt to changing forecasts to ensure a cost effective and reliable transmission system meeting the demands placed on it in these rapidly changing times.

In this regard, the transmission plan is somewhat of a bellwether of the changing demands placed on the transmission system and the broader range of conditions the transmission system will need to address and manage than in past transmission plans, but also reflects the need to adapt plans as circumstances change and new inroads are made on the broader electricity context in California – and energy footprint overall.

The transition to a generation fleet with significantly increased renewables penetration and "duck curve" issues, combined with increasing variability in net sales patterns due to behind-the-meter generation and other load-modifying behaviors, not only drive the ramping needs and flexible generation requirements within the electricity market, but are having an even more pronounced impact on the transmission grid as flow patterns change – and change frequently through each day – from traditional patterns. As these other changes, including growth in behind the meter generation, have been occurring more rapidly than originally anticipated only a few short years ago, both the techniques relied upon to assess system needs and certain previously planned projects themselves have needed to be revisited.

Each year's transmission plan is a product of timing, reflecting the particular status of various initiatives and industry changes in the year the plan is developed, as well as the progress in parallel processes to address future needs. The 2017-2018 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues as well as those triggered by more recent events, the progress made to meeting 33 RPS goals, and the ongoing development of various state agency processes and proceedings to address emerging challenges. The emerging issues and challenges are discussed in more detail in section 1.2 below, Impacts of the Industry Transformation.

Within this context, the transmission plan's primary purpose is to identify – based on the best available information at the time this plan was prepared – needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. A transmission plan may also identify any transmission solutions 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. In recommending solutions for identified needs, the ISO takes into account an array of considerations. Furthering the state's objectives of a cleaner future plays a major part in those considerations.

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2017-2018 planning cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to verify compliance with applicable NERC reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities ranging in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns including upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and identifying the potential for conventional and non-conventional resources to meet these needs.

Since implementing the current transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, both conventional generation and, in particular, preferred resources such as energy efficiency, demand response, renewable generating resources, and energy storage programs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades. For example, the ISO previously determined that a combination of transmission upgrades and preferred resources in concert would provide the most effective local capacity requirement replacement for the Oakland Generation Station should that plant retire, and PG&E and the ISO have been working towards that end – with further progress being made in this planning cycle. Further, load modifying preferred resource assumptions incorporated into the load forecasts adopted through state energy agency activities provide an additional opportunity for preferred resources to address transmission needs.

To increase awareness of the role of preferred resources, section 7.3 summarizes how preferred resources will address specific reliability needs. In addition, discussion throughout chapter 2 show the reliance on preferred resources to meet identified needs on an area-by-area study basis.

This transmission plan documents ISO analyses, results, and mitigation plans.[9] These topics are discussed in more detail below.

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support state and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California's renewable energy goals. The trajectory to achieving the 33 percent renewables portfolio standard set out in the state directive SBX1-2 has been largely established. As a result, the prior year's 33 percent renewable energy portfolios have not been modified. Efforts to establish state policy direction for resource planning to achieve the longer term renewable energy goal of 50 percent by 2030 set out in SB 350 are underway, and the ISO anticipates that, at the earliest, direction will be incorporated into the 2018-2019 planning cycle. The policy-driven analysis in this cycle therefore continued to focus on confirming the effectiveness of the plans for achieving the 33 percent RPS goal, and to refine our understanding of potential challenges and issues in moving beyond 33 percent both in preparation for our own future planning activities and to help inform resource planning processes underway in the state.

Economic-driven solutions are those that provide net economic benefits to consumers as determined by ISO studies, which includes a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses and access to lower cost resources for the supply of energy and capacity. As renewable generation continues to be added to the grid, with the inevitable economic pressure on other existing resources, economic benefits will also have to take into account cost effective mitigations of renewable integration challenges. In preparation of future industry discussions on these issues, the ISO updated the documentation of its current economic study methodologies[10] and anticipates needing to undertake other methodology enhancements to consider more nuanced and complex economic analyses in the future.

In addition to undertaking the aforementioned analyses required by the tariff, the ISO also continued with further analysis of a number of additional "special studies" that were undertaken in the 2016-2017 transmission planning cycle. The special studies are not required under the ISO tariff but are discretionary analyses to provide insight into emerging issues and help the ISO and industry better prepare for future planning cycles.

While considerable progress was made on those studies in the previous cycle, the need for further consideration was identified and incorporated into this year's study activities. In addition, other processes or proceedings are now playing a role in actively advancing or addressing the subject

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[9] This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan, the ISO has removed from this year's plan additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The ISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the ISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

[10] "Transmission Economic Assessment Methodology (TEAM)," November 2, 2017, http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf.

of a number of those studies, and the ISO is therefore directing its efforts to support those processes rather than focusing solely on the transmission planning cycle. The status of the special study work the ISO undertook in 2017 is discussed in this plan, as well as where the results of the special study efforts are available if not in this plan itself. The efforts in this year's planning cycle focused on:

- Continuing frequency response study efforts through improved modeling;
- Continuing the analysis of large scale storage benefits with further sensitivities;
- Further refinement of the necessary characteristics for slow response resources in local capacity areas;
- Continuing the analysis of the risks of early economic retirement of gas fleet;
- Gas/electric reliability coordination; and,
- Further analysis supporting 50 Percent Renewable Generation and Interregional Coordination activities, focusing on interregional transmission project analysis.

## 1.2 Impacts of the Industry Transformation

As state efforts continue to reduce the carbon footprint and other environmental impacts of the electricity industry, the ISO must address a growing range of considerations to ensure overall safe, reliable, and efficient operation through its planning process. These efforts include the continued growth of renewable generation on the ISO system whether grid-connected or behind-the-meter at end customer sites, the phase out of using coastal water for once-through-cooling at thermal generating stations, and a growing range of strategies, policy priority areas, emerging technologies and risks and opportunities to either achieve energy use reductions or the impacts of energy consumption. Many of these are no longer stand-alone solutions – they can achieve great outcomes if properly planned and implemented in concert with the right volumes of other mitigations, or fail to provide the expected benefits if implemented in isolation or carelessly.

These trends, including higher than previously expected levels of behind-the-meter solar generation, are producing new and more complex operating paradigms for which the ISO must consider in planning the grid. In its transmission planning processes, the ISO is therefore having to consider factors and trends reaching beyond the more specific and well-defined challenges of the past, such as the phasing out of gas-fired generation relying on coastal waters for once-through cooling as well as the early retirement of the San Onofre Nuclear Generating Station and the planned retirement of Diablo Canyon Nuclear Generating Station in 2024.

These new challenges and potential solutions must also consider the emergence of new policy and operating frameworks that will be relied upon to develop and coordinate the supply of, and demand for, electricity in the future.

Coupled with the changing generation resource fleet inside California, the increased emphasis on regionalism as a means to manage more economic dispatch and maximize the benefits of renewable generation development is both changing the nature of interchange with the ISO's neighboring balancing authority areas and increasing the variability in flows on a more dynamic basis. The success of and growing participation in the ISO's energy imbalance market results in more dynamic import and export conditions.

The rest of this subsection discusses a number of the emerging issues and factors together with the inputs considered in this transmission planning cycle, as well as the other actions being taken to advance the understanding or implementation of those issues in the future — whether special study activities, ISO policy initiatives or regulatory proceedings.

### 1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

**Base Forecasts**

The ISO continues to rely on load forecasts and load modifier forecasts prepared by the California Energy Commission (CEC) through its Integrated Energy Policy Report (IEPR) processes. The combined effects of flat or declining gross load forecasts and reductions in those net load forecasts due to behind-the-meter generation and energy efficiency programs continue to significantly impact the planning process:

- Declining net peak loads have led to the review of several previously-approved load growth-driven transmission projects, particularly in the PG&E area[11].
- The increasing variable loading on the transmission system is resulting in more widely varying voltage profiles, resulting in an increased need for reactive control devices to maintain acceptable system voltages.
- The rapid deployment of behind-the-meter generation is driving changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet.

The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available. This is an issue that has been progressing through subsequent IEPR processes, having first been noted in the CEC's 2015 effort.

The CEC's California Energy Demand 2016-2026 Revised Forecast (CED 2015) stated the following with respect to the impact of PV at the time of the forecast peak load:

[11] Because most of PG&E's low voltage sub-transmission facilities are under ISO operational control, there are a relatively large number of previously approved small and substantially unrelated projects in the PG&E area that were predominantly load-growth driven. This enabled the ISO to conduct a more programmatic approach in reviewing those projects in the 2015-2016 transmission planning cycle and again in this planning cycle. In contrast, the ISO has focused on a more case-by-case basis on a smaller number of larger and more heavily inter-related projects in the SDG&E and SCE service areas mitigating the loss of the San Onofre Nuclear Generating Station and once-through-cooling thermal generation retirements.

> *"At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, since staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the 2017 Integrated Energy Policy Report (2017 IEPR), and such an adjustment to PV peak impacts could significantly affect future peak forecasts.[12]"*

The ISO addressed this to some extent in the 2016-2017 transmission planning process by applying interim consideration of the impacts of the pace of behind-the-meter development. In the 2016-2017 TPP, the ISO used the CEC energy and demand forecast as the base scenario analysis for identifying new transmission system needs. As the ISO conducted sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, the ISO took into account — with the information available — the effect of the shift of peak loads described above and other forecasting uncertainties to develop sensitivity scenarios. The ISO relied on the results of its reliability analysis of select sensitivity scenarios, such as distributed PV peak shift or no additional achievable energy efficiency (AAEE), to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability. The ISO did not use the sensitivity scenarios to identify new needs triggering new transmission projects.

The ISO continued to work with the CEC on the hourly load forecast issue. Through discussions with the ISO and the California Public Utilities Commission (CPUC), the CEC addressed this issue more effectively in the California Energy Demand Updated Forecast 2017-2027 (CEDU 2016), which included a sensitivity scenario of the potential peak shift and the resulting impact on peak demand. The CEDU 2016 included a Peak-Shift Scenario Analysis and stated the following with respect to the use of the results of this analysis in the current ISO TPP studies:

> *"The results of the final adjusted managed peak scenario analysis can be used by the California ISO in TPP studies to review previously -approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in identifying new needs triggering new transmission projects, given the preliminary analysis. More complete analyses will be developed for IEPR forecasts once full hourly load forecasting models are developed."[13]*

Accordingly, in this year's 2017-2018 planning cycle, the ISO used the scenario analysis conducted by the CEC to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability, and the ISO did not use the sensitivity scenario to identify new needs triggering new transmission projects given the preliminary nature of the approach taken in the CEDU 2016.

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[12] CEC Staff Report, "California Energy Demand 2016-2026, Revised Electricity Forecast, Volume 1: Statewide Electricity Demand and Energy Efficiency," January 2016, at p. 37, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf

[13] CEC Staff Report, "California Energy Demand Updated Forecast, 2017-2027," January 2017, http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215275_20170112T135223_California_Energy_Demand_Updated_Forecast_20172027.pdf , at p. 51.

Further refinements are also expected in the development of the California Energy Demand Forecast 2018-2028 (CED 2017) that the ISO will use in the 2018-2019 transmission planning process. The ISO is particularly anticipating the usefulness of the full hourly load forecasting models being developed, as these will play a key role in the more complex analysis of the effectiveness of use-limited preferred resources as part of comprehensive solutions to reliability needs.

**Further Drivers**

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative, the ISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the ISO markets.

At the same time, the CPUC has placed an increased emphasis on incorporating DERs into its planning and procurement framework for jurisdictional utilities. These issues are being considered both in the CPUC's current Distribution Resource Planning proceeding, and identified in the 2017-2018 Integrated Resource Plan proceeding as an issue for future optimization in the subsequent 2019-2020 proceeding, as discussed in more detail below.

Further consideration of a range of industry trends and needs also drive an increased range of uncertainty about future requirements—with energy efficiency programs driving demand in one direction, but decarbonizing other sectors such as transportation potentially causing increased demand in new and previously unseen consumption patterns.

Also, the ISO will continue to explore the possibility for demand-side management tools to play a role in mitigating local reliability needs; those processes are considered as part of the resource planning processes discussed in the next subsection.

### 1.2.2 Resource Planning

Resource planning has informed past planning cycles by focusing primarily on informing policy-driven transmission needs to support state policy objectives on the development of renewable generation, and the role local resources—whether conventional or preferred resources—can play in meeting local reliability needs.

Regarding the former, the ISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for ISO to analyze in the ISO's annual TPP. These portfolios have been provided more recently through the CPUC's Long Term Procurement Plan proceedings, and more recently, transitioned to the CPUC's Integrated Resource Plan (IRP) proceeding.

**Integrated Resource Plan Process:**

While specific objectives have been established for the electricity industry through the Clean Energy and Pollution Reduction Act of 2015, the IRP process takes into account broader state objectives regarding reducing greenhouse gas emissions that are expected to reach beyond the requirements already set for the electricity industry.

Although considerable work remains to be done to ensure that the transmission plans in place are achieved, the ISO's focus in the 2017-2018 planning cycle was to confirm the effectiveness of current plans to achieve the previous 33 percent RPS goal and to continue the special study analysis started in the 2016-2017 planning cycle to support moving beyond the 33 percent goal and driving to the 50 percent goal.

As specified in the "Draft 2017 Assumptions and Scenario for Long Term Planning"[14], document provided via a ruling in the CPUC's IRP proceeding, a single Reliability Scenario has been included as a Planning Scenario. This scenario uses the same RPS portfolio that was supplied by Commission staff to the ISO for the 2016-2017 TPP, the "33% 2025 Mid AAEE" trajectory portfolio. Because this portfolio was not expected to be significantly different from the 33 percent portfolio studies as part of the 2015-216 and 2016-2017 TPP, these resources were studied as part of the long-term reliability assessment base cases only — no additional policy analysis was warranted given the studies conducted in earlier planning cycles.

Through 2017, the ISO also supported the development of the CPUC's IRP framework and related activities.

### Clean Energy and Pollution Reduction Act of 2015

On October 7, 2015 Governor Jerry Brown signed into law SB 350, the Clean Energy and Pollution Reduction Act of 2015 authored by Senator Kevin De León. The bill established the following goals:

- By 2030, double energy efficiency for electricity and natural gas by retail customers
- 50 percent renewables portfolio standard (RPS) by 2030
    - Existing RPS counting rules remain unchanged
    - Requires LSEs to increase purchases of renewable energy to 50 percent by December 31, 2030
    - Sets interim targets as follows
        - 40 percent by the end of the 2021-2024 compliance period
        - 45 percent by the end of the 2025-2027 compliance period
        - 50 percent by the end of the 2028-2030 compliance period

SB 350 creates a pathway to increased levels of renewable generation and lower greenhouse gas emissions.

### Renewable Energy Transmission Initiative (RETI 2.0)

[14] The "Draft 2017 Assumptions and Scenario for Long Term Planning" is included as an attachment to Administrative Law Judge Julie A. Fitch's ruling seeking comment, issued in CPUC Proceeding No. R.16-02-007, January 18, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF.

Another outcome of SB 350 was that new investments in the state's electric transmission system may be required to achieve the renewable energy goals, which will necessarily require planning and coordination across California and the West. The ISO expects that policy direction from the state will evolve through the CPUC's IRP processes.

To assist in this effort, the ISO partnered in 2015 and 2016 with the CEC and the CPUC, to conduct the Renewable Energy Transmission Initiative (RETI 2.0). RETI 2.0 was an open, transparent, and science-based process exploring the viability of renewable generation resources in California and throughout the West, considering critical land use and environmental constraints, and identifying potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits.

California faced similar challenges in 2007 when the state implemented a 20 percent renewable energy target, while looking forward to a 33 percent goal. The 2008 Renewable Energy Transmission Initiative (RETI), a non-regulatory statewide planning process, was established to identify the transmission projects needed to support the renewable generation that would help meet the 33 percent target.

Although RETI 2.0 was not a regulatory proceeding in itself, the insights, scenarios, and recommendations it generated will frame and inform future transmission planning processes and proceedings with stakeholder-supported strategies to help reach the state's 2030 renewable energy goals.

RETI 2.0 was officially launched on September 10, 2015 with a public workshop. The ISO and State agencies established an over-arching plenary group and two working groups that supported the plenary group:

- The Plenary Group's role was to:
    - o Discuss and vet planning assumptions, utilizing data from CEC, CPUC, ISO, that support the overall goals of RETI 2.0 process, in light of statewide GHG and renewable energy goals;
    - o Qualitatively discuss what the state should be looking for in selecting resource areas;
    - o Consider potential environmental and land use information to assist with identifying lower conflict areas for potential renewable energy development; and,
    - o Construct and discuss combinations of renewable energy resource areas and associated transmission improvements that can help achieve California's 2030 climate and renewable energy goals.
- The Environmental and Land Use Technical Group, led by the CEC in close coordination with local governments, tribes, and other agencies with relevant environmental and land use expertise, assisted in assessing environmental and land use considerations related to possible locations for renewable energy development.
- The Transmission Technical Input Group, led by the ISO, worked with California planning entities to assemble relevant in-state and west-wide transmission capability and upgrade

cost information to inform resource development combinations on the reasonably-needed transmission system implications and to assist in developing potential corridor scenarios.

The RETI 2.0 reports are publicly available on the CEC website[15].

**Market pressure on gas-fired generation fleet – and new expectations on the fleet.**

The significant amount of new renewable generation being added to the grid continues to put economic pressure on downsizing the existing gas-fired generation fleet. To understand the risk of a material amount of similarly situated generation retiring more or less simultaneously, the ISO initiated special studies in the 2016-2017 transmission planning cycle, with additional analysis extending into the 2017-2018 time frame, to assess the risks. The 2016-2017 studies did not find new geographic areas of concern exposed to local reliability risk if faced with retirement risks at levels that approached the limit of acceptable system capacity outside of the pre-existing local capacity areas. Those studies also identified potential system-wide reserve margin issues emerging with as little as 1000 to 2000 MW of retirements beyond the current planned retirements.

The downward economic pressure on the gas-fired generation fleet not under long-term contracts has also raised local capacity concerns that have led to the ISO entering in 2017 into the first new reliability must-run ("RMR") agreements[16] for generation capacity since 2006, as well as to issue annual capacity procurement mechanism ("CPM") designations for two generating facilities[17] for 2018. This has led to both concerns about how the capacity is procured, and renewed focus on finding alternatives that would reduce local resource capacity requirements in specific local capacity areas, which also puts additional economic pressure on generation in those specific areas. For example, on January 11, 2018, the CPUC adopted Resolution E-4909, authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability. The ISO is working with PG&E to incorporate energy storage, preferred resources, and transmission upgrades to achieve an overall comprehensive and economic solution to these local needs, and is advancing several transmission upgrades in this transmission plan as part of that effort. While targeting alternatives to achieve overall reductions in local capacity requirements may be an area of new policy direction from the state, the ISO is considering how to address these concerns as potential economic studies in this and future planning cycles.

At the same time, the gas-fired generation fleet is expected to play a major role in renewable generation integration for some years into the future, as discussed below, at least on an interim basis. The success of emerging market frameworks to better identify and value the resources with the necessary attributes will also need to be factored into this thinking.

Thus, study efforts focusing on reducing costs to consumers by reducing local capacity requirements will need to take into account the current and future economics of existing local capacity resources, the renewable integration benefits the generation may provide and the system need to retain that generation, and other criteria and characteristics that can make certain

[15] http://www.energy.ca.gov/reti/. The RETI 2.0 Plenary Report – Final Report, February 23, 2017, http://www.energy.ca.gov/reti/reti2/documents/index.html.

[16] These new RMR agreements are for the Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center.

[17] The two generating facilities are the Encina Power Station and Moss Landing Power Plant.

generators in the existing fleet more or less advantageous in prioritizing study efforts and in committing to alternatives to reduce local capacity needs. The consideration of these parameters will be made more complex as the various capacity procurement frameworks are being reviewed.

Along with other stakeholders, the ISO has supported and encouraged a broader review of the current resource adequacy framework in the CPUC's current Resource Adequacy proceeding. In the CPUC's "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years", the Commission noted that:

> *"[g]iven the passage of time and the rapid changes occurring in California's energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission's [resource adequacy] program."*[18]

The ISO has strongly supported this notion and urged the CPUC to open a separate track within this proceeding dedicated solely to addressing the fundamental structure of the resource adequacy program in light of a grid that is rapidly transforming, to ensure resources have the right capabilities and are available when and where needed to meet system needs.

To effectively and efficiently maintain grid reliability while incorporating greater amounts of preferred resources, the resource adequacy program must be restructured to identify not only the appropriate quantity and location of necessary resources, but also the performance characteristics required to balance supply and demand, which has become significantly more variable. The traditional one-year resource adequacy cycle does not provide a sufficient opportunity or time to thoroughly consider a holistic restructuring of the existing paradigm. As a result, the ISO has recommended that the CPUC establish a separate, dedicated track of this proceeding — that operates on an extended timeline — to consider fundamental resource adequacy restructuring issues.

In parallel, the ISO has already conducted some review of existing ISO "backstop" procurement mechanisms, and more review is planned and underway.

On January 12, 2017, the ISO filed a tariff amendment with the Federal Energy Regulatory Commission to improve its "risk of retirement" CPM designation process – which addresses an identified need a year hence, but where the generation is at risk of retiring during the intervening year – by making it more efficient and workable. Among other things, the proposed tariff amendments establish a revised framework that will allow the ISO, in specific circumstances, to signal its intent to designate a resource needed for reliability earlier in the year.

The ISO is also initiating a broader initiative reviewing the existing RMR and CPM frameworks, to review the RMR tariff, agreement and process and seek to clarify and align the use of RMR procurement versus backstop procurement under the CPM tariff. It is expected to proceed in two phases. The first phase will include RMR items that require immediate attention and implementation, such as having a must-offer obligation on RMR units that is the same as the must-offer obligation that units are subject to under the resource adequacy program and CPM

[18] *Order Instituting Rulekmaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2010 Compliance Years,* CPUC Proceeding No. R.17-09-020, at p. 3 (OIR), October 4, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747674.PDF.

tariff. The second phase will address potential additional refinements to the RMR tariff, agreement and process and create a unified procurement framework for using RMR procurement versus CPM backstop procurement.

**Renewable Integration Issues and Initiatives**

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – the ISO must address a broader range of considerations to ensure overall safe, reliable and efficient operation. Specifically, the changing nature and location of generation resources and their diurnal output pattern plus evolving load profiles, change the resulting demands on the transmission system.

The ISO currently conducts a range of studies to support the integration of renewable generation, including planning for reliable deliverability of renewable generation portfolios (chapter 4), generation interconnection process studies conducted outside of the transmission planning process but closely coordinated with the transmission planning process, and renewable integration operational studies that the ISO has conducted outside of the transmission planning process.

Past renewable integration operational studies focused primarily on the need for flexible resource capabilities. The genesis of the ISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding, docket R.10-05-006, wherein the ISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and the ISO has continued to analyze those issues. The ISO's efforts have led to a number of changes in market dispatch and annual resource adequacy program requirements, including incorporating ramping needs into the market dispatch and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising steps, the ISO has launched a stakeholder process to address a number of potential areas requiring refinements. Of particular concern from the infrastructure perspective is that "the flexible capacity showings to date indicate that the flexible capacity product, as currently designed, is not sending the correct signal to ensure sufficient flexible capacity will be maintained long-term."[19] This effort is also expected to consider if and how the transmission service necessary to ensure access to flexible capacity needs to be assessed — the "flexible capacity" equivalent of deliverability assessed for local and system capacity.

While the future impacts of the resource changes underway on the generation fleet are not fully understood at this time, past special study efforts and other initiatives have led to a number of outcomes and identified the need for more focused initiatives in the future. These include the previously-mentioned studies focusing on the impacts of potential economic-driven early retirement of gas-fired generation and need to review and upgrade generation models used in frequency response studies discussed in more detail below. The latter builds on the frequency response analysis the ISO conducted in the 2015-2016 planning cycle, where the ISO observed

[19] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative, November 8, 2016, at p.3, available at http://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

that simulated results varied from real-time actual performance – necessitating a review of the generator models employed in ISO studies. The shifting load shape also necessitates reconsideration of how the effectiveness of resources are gauged in meeting capacity needs.

Further, the ISO expanded and refined a special study focusing on the potential benefits of a large scale storage project, both to help managing system-wide ramping and flexibility needs and potentially provide locational transmission benefits to the transmission system, initially conducted in the 2016-2017 planning cycle and discussed in section 6.

### Impact on Capacity Considerations of Changing Load Profiles

The ISO is considering the impact of the shifting net sales peak to later hours on other aspects of our reliability analysis. In particular, the methodology used to consider the deliverability of various resources, such that the resources can provide capacity into the state's resource adequacy program, was developed at a time where the vast bulk of the capacity – gas fired generation in particular – was fully dispatchable. Initial levels of renewable generation were treated as incremental to the "core" of other dispatchable resources, and incorporated into deliverability methodologies with certain modest variations to their production levels to reflect their specific characteristics, driving the resources' Qualifying Capacity as determined by the CPUC.

However, with the significant levels of both grid-connected and behind-the-meter generation being developed, this incremental approach is no longer viable due to the peak shift impact on net sales and declining correlation between the net sales peak load and the output of grid-connected solar generation. This issue came to the forefront in the ISO's 2018 Local Capacity Technical Study and the analysis of the combined San Diego-Imperial Valley area, where the final capacity benefit assigned by the CPUC to solar resources in the area landed between the bookend scenarios studied by the ISO. Beyond these immediate impacts, however, the shift indicates the need to also revisit the deliverability methodology used by the ISO to both award "full capacity deliverability status" for local and system capacity purposes, and to assess deliverability in transmission planning and reliability studies. The ISO expects this will be the subject of a planning-related stakeholder initiative commencing in 2018, and that will require considerable coordination with the CPUC and other state agencies. In the meantime, the ISO continues to use existing methodologies in this planning cycle, tempered with sensitivities as needed.

### Non-Transmission Alternatives and Preferred Resources

Building on efforts in past planning cycles, the ISO continues to make material strides in facilitating use of preferred resources to meet local transmission system needs.

The ISO's approach, as noted in previous transmission plans, has focused on specific area analysis and testing the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for reliability concerns.

This approach is set out in concept in the study plan for this planning cycle, developed in phase 1 of the planning process as described below, and has built on and refers to a methodology the

ISO presented in a paper issued on September 4, 2013,[20] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[21] — energy efficiency, demand response, renewable generating resources, and energy storage — by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. In addition to developing a methodology the ISO could apply annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-Area Local Capacity Alternative Study released on August 16, 2017.[22] In addition, then ISO has developed a methodology as discussed in section 6.6 for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds on and expands on the analysis framework of preferred resources.

These efforts, with the additional detail discussed below, help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs. The ISO must also consider the cost effectiveness and other benefits these alternatives provide.

Although the Board does not "approve" non-transmission (*e.g.*, preferred resource capacity) solutions, the ISO can identify these solutions as preferred solutions to transmission projects and then work with the appropriate local regulatory authorities to support their development. This is particularly viable when the transmission solution is not needed to be initiated immediately and where time can be set aside to explore the viability of non-conventional alternatives first while relying on a more conventional transmission alternative as a backstop.

In examining the benefits preferred resources can provide, the ISO relies heavily on preferred resources identified through various resource procurement proceedings as well as proposals received in the request window and other stakeholder comment opportunities in the transmission planning processes.

*High potential areas:*

Each year's transmission plan identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the

[20] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

[21] To be precise, the term "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

[22] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

planning area discussions in chapter 2 contain a section describing the preferred resources that are providing reliability benefits, and the ISO has summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 7.3.

*Energy storage:*

In addition to considering energy storage as part of the overall preferred resource umbrella in transmission planning, the ISO is engaged in a number of parallel activities to facilitate energy storage development overall, including past efforts refining the generator interconnection process to better address the needs of energy storage developers. One such effort is the continued refinement of the analysis of the benefits of large scale energy storage in addressing flexible capacity needs, as mentioned earlier and discussed in section 6.3. This analysis began in the 2015-2016 transmission planning cycle, and was updated and expanded, including consideration of locational benefits, in the 2016-2017 cycle. In 2017, the ISO conducted additional analysis as an extension of the 2016-2017 planning cycle. Storage also played a major role in the assessment of the viability of preferred resource alternatives in the Moorpark Sub-Area Local Capacity Alternative Study discussed earlier.

The market and regulatory framework for storage that is meeting energy market and transmission system needs is also evolving. Utilization of electric storage resources is a significant issue to the ISO, given the industry development underway and the potential for electric storage to play a growing role in the reliability of the transmission system, as well as a growing role in renewable integration and overall system efficiency.

Existing procurement mechanisms can support and have supported storage resources providing these services through the ISO's wholesale markets coupled with procurement directed by the CPUC. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the resource to participate most broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and behind-the-meter resources that do not participate in the ISO's wholesale markets. In the system resource context, the storage resource would be functioning primarily as a market resource, with contractual obligations to the off-taker to provide certain services supporting local reliability. This approach, which has been successful in the past, may become more problematic as utilities become concerned with the ability to share the costs of these resources across all consumers that are benefiting from the enhanced reliability, and become less willing to enter into resource procurement contracts.

The ISO has also studied in past planning cycles a number of potential applications of energy storage as transmission assets, and in that evaluation, assumed the energy storage would not be able to provide other market services and access other market-based revenue streams. The ISO had relied on the Federal Energy Regulatory Commission's (FERC's) guidance that transmission assets – and in particular the use of electric storage as a transmission asset – should provide transmission services focusing on thermal loading and voltage support and considered that direction appropriate and particularly helpful to the ISO in past transmission planning processes. In the context of our transmission planning process, the ISO has studied a number of potential electric storage projects as reliability solutions in the form of transmission asset models.

Consistent with past FERC direction, these storage projects were assumed to be precluded as transmission assets from participating in energy or ancillary services markets.

On January 19, 2017, FERC issued its policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" to:

> *"provide guidance and clarification regarding the ability of electric storage resources to receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services.* [23]*"*

The policy statement also sets out a number of concerns that would need to be addressed in order to enable this outcome. The ISO notes that at face value, the policy statement's references to "cost based rate recovery" appear to include both transmission rate base treatment of a regulated asset, or other agreement analogous to the ISO's existing reliability must-run agreements, wherein the asset is not part of rate base, but is receiving cost-based rate recovery for providing specific services. These reliability must-run agreements generally currently serve to maintain existing resources rather than be relied upon to procure new resources.

Accordingly, the ISO has begun the stakeholder consultation process to address the implementation concerns set out in the policy statement, commencing with gathering input from industry as to the priority of this initiative relative to other ISO policy development. This initiative was added to the catalog by the ISO in October 2017. This initiative would consider using electric storage to provide grid services as a transmission facility, with all or a portion of costs recovered through the transmission access charge. This initiative would further explore issues around electric storage resources seeking to receive cost-based rate recovery for certain services (transmission, grid support services, or other needs identified by an RTO/ISO). It would also explore storage resources receiving market-based revenues for providing separate market-based rate services.

As these mechanisms have not yet been developed, the ISO has continued in this planning cycle to evaluate energy storage as potential alternatives to system reinforcement as either local capacity – as discussed above – or as transmission assets with all cost recovery through regulated rates. As the issues associated with multiple revenue streams is addressed through the policy initiative, the assessment methodologies will be adapted in future planning cycles.

*Use-limited resources, including demand response:*

The ISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC's demand response related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system needs.

[23] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[24]

The ISO anticipates that there will be more progress for demand response and other use-limited resources in this area.

### 1.2.3 System Modeling, Performance, and Assessments

**System modeling requirements and emerging mandatory standards**

Exploring an increased role for preferred resources to address both traditional and emerging needs poses new technical challenges. The grid is already being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

Also, this has led to the need for greater accuracy in planning studies, and in particular, to the special study initiative undertaken in the 2016-2017 planning cycle reviewing all generator models for use in dynamic stability studies and frequency response analysis.

The efforts undertaken in the previous planning cycle and continued through this cycle in 2017 reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.4) However, the effort also identified underlying challenges with obtaining validated models for a large – and growing – number of generators that are outside of the bounds of existing NERC mandatory standards and for which the ISO is dependent on tariff authority. The ISO will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information, as well as pursuing additional regulatory measures to ensure validated models are provided by generation owners.

**Southern California Reliability and Gas-Electric Coordination**

As in previous transmission plans, the ISO placed considerable emphasis in the 2016-2017 planning cycle on requirements in the Los Angeles basin and San Diego areas. The ISO has expanded the focus in past planning cycles on addressing the implications of the San Onofre Nuclear Generating Station's early retirement and the anticipated retirement of once-through-cooling gas fired generation to also consider the impact of the uncertainty regarding the Aliso Canyon gas storage facilities on local area gas supply. The high expectations of preferred resources being part of a comprehensive solution, which also includes transmission reinforcement and conventional generation, has resulted in the ISO analyzing the role of preferred resources in that area.

[24] See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

Successfully mitigating reliability concerns remains dependent on materially higher levels of preferred resources in the future than have previously been achieved. Given the uncertainty regarding forecast resources materializing as planned, the ISO is continuing to monitor the progress of the forecast procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. Section 2.6 touches on these issues.

## 1.3 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. For example, the 2016-2017 planning cycle began in January 2016 and concluded in March 2017.

Phase 1 includes establishing the assumptions and models for use 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 beginning year.

In Phase 2, the ISO performs studies to identify the solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the ISO is relying upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

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

In addition, the ISO may incorporate into the annual transmission planning process specific transmission planning studies necessary to support other state or industry informational requirements to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these focus primarily on grid transformation issues and incorporating renewable generation integration studies into the transmission planning process.

### 1.3.1 Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan. Continuing with the timelines and coordination achieved in past planning cycles, the generating resource portfolios used to analyze public policy-driven transmission needs were developed as part of the unified planning assumptions in phase 1 for the 2016-2017 planning cycle. In 2016, the ISO sought to further improve the level of coordination between the policy-driven generating resource portfolios and other planning assumptions — in particular the load forecast and load modifying behind-the-meter distributed generation.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO performs in phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other pertinent 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 it will consider in assessing the need for new transmission infrastructure.

Development of the unified planning assumptions for this planning cycle benefited from further coordination efforts between the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the ISO, building on the staff-level, inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- Long-term forecast of energy demand produced by the CEC as part of its biennial Integrated energy policy report (IEPR);
- Biennial integrated resource plan proceedings (IRP) and long term procurement plan proceedings (LTPP) conducted by the CPUC; and,
- Annual transmission planning process (TPP) performed by the ISO.

That forum resulted in improved alignment of the three core processes and agreement on an annual process to be undertaken in the fall of each year to develop planning assumptions and scenarios to be considered in infrastructure planning activities in the upcoming year. The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios discussed in more detail below, which are a key assumption.

The results of that annual process fed into this 2016-2017 transmission planning process and was communicated via a ruling in the 2014 LTPP[25]. These process efforts continued in 2017 emphasizing the broad load forecast impacts of distributed generation and other material changes in customer needs and considering renewable integration challenges and the market impacts of increased renewable generation on the existing conventional generation fleet.

The ISO added public policy requirements and directives as an element of transmission planning process in 2010. Planning transmission to meet public policy directives is also a national requirement under Federal Energy Regulatory Commission (FERC) Order No. 1000. It enables the ISO to identify and approve transmission facilities that system users will need to comply with specified state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles has been California's renewables portfolio standard that calls for 33 percent of the electric retail sales in the state by 2020 to be provided from eligible renewable resources. As discussed later in this section, the ISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but the ISO has taken steps in this transmission plan to incorporate those requirements into annual transmission plan activities.

The ISO formulates the public policy-related resource portfolios in collaboration with the CPUC, and with input from other state agencies including the CEC and the municipal utilities within the ISO balancing authority area. The CPUC, as the agency that oversees the bulk of the supply

[25] "Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings," May 17, 2016, CPUC Proceeding No. R.13-12-010, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF.

procurement activities within the ISO area, plays a primary role formulating the resource portfolios. The ISO reviews the proposed portfolios with stakeholders and seeks their comments, which the ISO then considers in determining the final portfolios.

The resource portfolios have played a crucial role in identifying needed public policy-driven transmission elements. Meeting the renewables portfolio standard has entailed developing substantial amounts of new renewable generating capacity, which in turn required new transmission for delivery. The ISO has managed the uncertainty as to where the generation capacity will locate by balancing the need to have sufficient transmission in service in time to support the renewables portfolio standard against the risk of building transmission in areas that do not realize enough new generation to justify the cost of such infrastructure. This has entailed applying a "least regrets" approach, whereby the ISO first formulates alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio, and then selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

As we move closer to the 33 percent renewables portfolio standard compliance date of 2020, much of the uncertainty about which areas of the grid will actually realize most of this new resource development as a result of the utilities' procurement and contracting processes has been addressed. As noted earlier, the portfolios intended to meet the 33 percent renewables portfolio standard vary less each year as we move closer to 2020, and the portfolios the ISO has relied upon in this planning cycle are unchanged from the last planning cycle. Accordingly, the ISO's focus in the 2017-2018 planning cycle was to confirm the effectiveness of current plans for achieving the 33 percent renewables portfolio standard and beginning analysis that will support moving toward the 50 percent goal by 2030 established by SB 350. This latter effort was reflected in the informational special studies that are discussed in chapter 6.

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. 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 selects high priority studies from these requests and includes them in the study plan published at the end of phase 1. The ISO may modify the list of high priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

In 2017, the ISO sought and received FERC approval to modify its tariff and discontinue the development of the conceptual statewide transmission plan, which had initially been added in 2010 to the ISO planning process, but which became redundant with the subsequent development of FERC Order No. 1000 interregional planning coordination processes.

### 1.3.2 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 solutions required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. In phase 2, the ISO conducts the following major activities:

- Performs technical planning studies described in the phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO's technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- 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 final comprehensive transmission plan;
- Coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC long-term procurement proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities 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;
- Performs a "least regrets" analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[26] which is intended to minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- Identifies additional category 2 policy-driven potential transmission facilities 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;
- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- 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 AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;

[26] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables 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. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

- Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and,
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2 in March.

Board approval of the comprehensive transmission plan at the end of phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval.[27] As indicated above, the ISO solicits and accepts proposals in phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated 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 solutions satisfy the least regrets criteria and should be elevated to category 1 status, should remain category 2 projects for another cycle, or should be removed from the transmission plan.

As noted earlier, phases 1 and 2 of the transmission planning process encompass a 15-month period. Thus, the last three months of phase 2 of one planning cycle will overlap phase 1 of the next cycle, which also spans three months. The ISO will conduct phase 3, the competitive solicitation for sponsors to compete to build and own eligible regional transmission facilities reflected in the final Board-approved plan.[28]

### 1.3.3 Phase 3

Phase 3 takes place after Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional reliability-driven, category 1 policy-driven, or economic-driven transmission solutions, except for regional transmission solutions that are upgrades to existing facilities. Local transmission facilities are not subject to competitive solicitation.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO will commence phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the ISO will select an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified

[27] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. The ISO includes such projects in the comprehensive plan as pre-approved by ISO management and not requiring Board approval.

[28] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

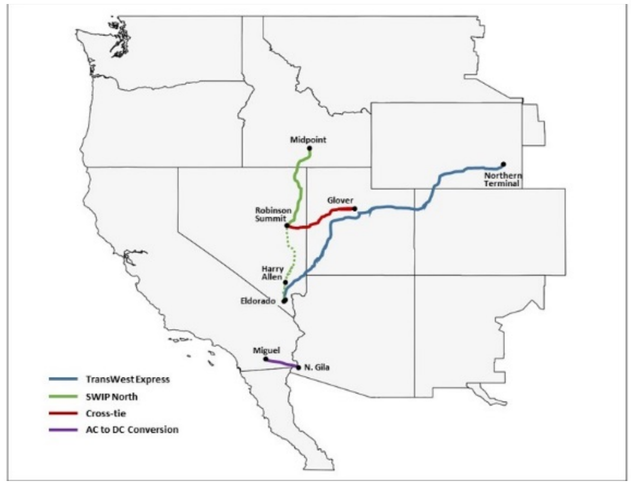
## 1.4 Interregional Transmission Coordination per FERC Order No. 1000

During the ISO's 2017-2018 planning cycle, the ISO continued to participate and advance interregional transmission coordination along with the other Western Planning Regions[29] within the broader landscape of the western interconnection. December 31, 2017 marked the close of the 2016-2017 Western Planning Region interregional coordination cycle where the Western Planning Regions implemented refinements of various aspects of their regional processes such as guiding principles to ensure that an annual exchange and coordination of planning data and information was achieved in a manner consistent with expectations of FERC Order No. 1000. Further, during this interregional coordination cycle the Western Planning Regions held two Annual Interregional Coordination Meetings, February 25, 2016 and February 23, 2017, respectively, to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[30]

The ISO hosted its submission period in the first quarter of 2016 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31st with four interregional transmission projects being submitted to the ISO. The submitted projects are shown in Figure 1.4-1.

Following the submission and successful screening of the interregional transmission project submittals, the ISO coordinated its interregional transmission project evaluation with the other relevant planning regions NTTG and WestConnect. By the end of Q1 2017 NTTG and WestConnect, through their regional processes, determined that none of the submitted interregional transmission projects were needed in their regional plans and as such, they were no longer considered relevant planning regions and no further analysis on these projects were conducted by NTTG and WestConnect.

Figure 1.4-1: Interregional Transmission Projects Submitted to the ISO




However, within California there remains a considerable interest in exploring the benefits of interregional transmission projects in moving beyond 33 percent RPS towards 50 percent RPS. Although NTTG and WestConnect determined the interregional transmission projects were not needed in their regional plans, the ISO continued to consider these proposed projects in the context of an extension of the 50 percent RPS special studies that had been initiated in the 2016-2017 transmission planning cycle. While the policy direction is not in place at this time to consider these alternatives as policy-driven transmission, the ISO desired to fully vet the value that these proposed project could contribute towards California's renewable goals. To this end, the ISO continued to coordinate information with the other planning regions to complete its final

[29] Western planning regions are the California ISO, ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect.

[30] Documents related to the 2016-2017 interregional transmission coordination meetings are available on the ISO website at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=D9852CD6-192B-46E2-8CA5-799557EDBF94.

assessments of these project. Additional details of the ISO's extended 2016-2017 transmission plan assessment of the interregional transmission project proposals is provided in section 6.1 of this transmission plan.

*WECC Anchor Data Set*

The 2016-2017 transmission plan discussed the WECC Anchor Data Set (ADS) and the initial steps that had been undertaken to implement development of the ADS. During the 2017-2018 transmission planning cycle, the ISO continued to participate with the other planning region and WECC to implement the ADS by the end of June 2018. The planning regions consider the full implementation of the ADS to be a significant step towards meeting their need of resolving existing data inconsistencies and applications while facilitating a common dataset that accurately represents the regional plans of all four planning regions.

The ISO continued to provide leadership in working with the other planning regions and in particular WECC, to further refine and develop implementation protocols for the ADS. The 2017-2018 transmission planning cycle saw the full implementation of the WECC Reliability Assessment Committee (RAC) and its subcommittee and workgroups. The planning regions have worked through the RAC committee structure to identify and assign data responsibilities to the planning regions and RAC to ensure that the ADS will fulfill its objective for the planning regions and WECC. To support ADS implementation, the RAC formed the ADS Task Force, the members of which include representatives from the planning regions and other WECC member representatives which were selected through a formal WECC nomination process. The ADS Task Force held its first meeting in Q4 2017 and is actively engaged in consideration of the implementation of the ADS and proposing any recommended changes to RAC that they may need to consider. The due date for completing the first ADS production cost model is a 2028 PCM dataset by the end of June 2018.

## 1.5 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes. These processes and initiatives are briefly summarized below.

### Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process. The ISO applied the GIDAP to queue cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier will continue to be subject to the provisions of the prior generation interconnection process (GIP).

The principal objective of the GIDAP was to ensure that going forward the ISO would identify and approve all major transmission additions and upgrades to be paid for by transmission ratepayers under a single comprehensive process — the transmission planning process — rather than having some projects come through the transmission planning process and others through the GIP.

The most significant implication for the transmission planning process at this time relates to the planning of policy-driven transmission to achieve the state's 33 percent renewables portfolio standard. In that context, the ISO plans the necessary transmission upgrades to enable the deliverability of the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC, unless specifically noted otherwise. Every RPS Calculator portfolio the CPUC has submitted into the ISO's transmission planning process for purposes of identifying policy-driven transmission to achieve 33 percent RPS has assumed deliverability for new renewable energy projects.[31]

Through the GIDAP, the ISO then allocates the resulting MW volumes of transmission plan deliverability to those proposed generating facilities in each area that are the most viable based on a set of project development milestones specified in the tariff. Interconnection customers proposing generating facilities that are not allocated transmission plan deliverability, but who still want to build their projects and obtain deliverability status, are responsible for funding needed delivery network upgrades at their own expense without being eligible for cash reimbursement from ratepayers.

#### *Transmission Plan Deliverability*

As set out in Appendix DD (GIDAP) of the ISO tariff, the ISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the ISO considered queue clusters up to and including queue cluster 10.

[31] RPS Calculator User Guide, Version 6.1, p. A-17. ("In prior versions of the RPS Calculator (v.1.0 – v.6.0), all new renewable resources were assumed to have full capacity deliverability status (FCDS).") Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5686.

*Distributed Generation (DG) Deliverability*

The ISO developed a streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity in 2012 and implemented it in 2013. The ISO completed the first cycle of the new process in 2013 in time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The ISO annually performs two sequential steps. The first step is a deliverability study, which the ISO performs within the context of the transmission planning process, to determine nodal MW quantities of deliverability status that can be assigned to DG resources. The second step is to apportion these quantities to utility distribution companies — including both the investor-owned and publicly-owned distribution utilities within the ISO controlled grid — who then assign deliverability status, in accordance with ISO tariff provisions, to eligible distributed generation resources that are interconnected or in the process of interconnecting to their distribution facilities.

In the first step, during the transmission planning process the ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes 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 for use in the DG deliverability study, the ISO models the existing transmission system, including new additions and upgrades approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify 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 distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns with the public policy objectives addressed in the current transmission planning process 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 transmission planning process.

In the second step, the ISO specifies how much of the identified DG deliverability at each node is available to the utility distribution companies that operate distribution facilities and interconnect distributed generation resources below that node. FERC's November 2012 order stipulated that FERC-jurisdictional entities must assign deliverability status to DG resources on a first-come, first-served basis, in accordance with the relevant interconnection queue. In compliance with this requirement, the ISO tariff specifies the process whereby investor-owned utility distribution companies must establish the first-come, first-served sequence for assigning deliverability status to eligible distributed generation resources.

Although the ISO performs this new DG deliverability process as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is adding the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

### Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[32] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

### Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014, [33] in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities.

Beginning in 2015, the ISO reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator to determine whether they needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, under the planning coordinator services agreement the ISO is not responsible for planning and approving mitigations to identified reliability issues – but only verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

The ISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power and the Metropolitan Water District, and the ISO has conducted the study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process. In Q4 2017 the ISO executed a planning coordinator services agreement with the City of Santa Clara, doing business as Silicon Valley Power (SVP). The ISO will begin providing those services in 2018 and through a two-year implementation plan will collect all required information to fulfill its planning coordinator responsibility for SVP.

Finally, the ISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are not under ISO operational control but which were found to be Bulk Electric System as defined by NERC.

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[32] ISO tariff section 20 addresses how the ISO shares Critical Energy Infrastructure Information (CEII) related to the transmission planning process with stakeholders who are eligible to receive such information. The tariff definition of CEII is consistent with FERC regulations at 18 C.F.R. Section 388.113, *et. seq*. According to the tariff, eligible stakeholders seeking access to CEII must sign a non-disclosure agreement and follow the other steps described on the ISO website.

[33] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2), http://www.caiso.com/Documents/TechnicalBulletin-CaliforniaISOPlanningCoordinatorAreaDefinition.pdf.

At this time, the ISO is not anticipating offering these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO footprint requiring these services.

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

This study is part of the annual transmission planning process and performed 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; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

### 2.1.3 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. The regional planning areas are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below.

- PG&E Local Areas
  - Humboldt area;
  - North Coast and North Bay areas;
  - North Valley area;
  - Central Valley area;
  - Greater Bay area;
  - Greater Fresno area;
  - Kern Area; and
  - Central Coast and Los Padres areas.
- SCE local areas
  - Tehachapi and Big Creek Corridor;
  - North of Lugo area;
  - East of Lugo area;
  - Eastern area; and
  - Metro area.
- Valley Electric Association (VEA) area
- San Diego Gas Electric (SDG&E) local area

### 2.1.4 Peak Demand

The ISO-controlled grid peak demand in 2017 was 50,116 MW and occurred on September 1 at 3:58 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

- PG&E peak demand occurred on September 1, 2017 at 5:44 p.m. with 21,783 MW;
- SCE peak demand occurred on September 1, 2017 at 3:41 p.m. with 24,380 MW;
- SDG&E peak demand occurred on September 1, 2017 at 3:53 p.m. with 4,553 MW; and
- VEA peak demand occurred on June 19, 2017 at 4:00 p.m. with 133 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 and the Central Coast in the PG&E service territory.

## 2.2 Reliability Standards Compliance Criteria

The 2017-2018 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 2018-2027 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2017-2018 study.

### 2.2.1 NERC Reliability Standards

#### 2.2.1.1 *System Performance Reliability Standards*

The ISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which provide 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 drivers determining reliability upgrade needs:

- TPL-001-4 Transmission System Planning Performance Requirements[34]; and
- NUC-001-2.1 Nuclear Plant Interface Coordination.

### 2.2.2 WECC Regional Criteria

The WECC TPL system performance criteria are 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.[35]

### 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.[36] 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.

[34] Analysis of Extreme Events or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

[35] https://www.wecc.biz/Standards/Pages/Default.aspx

[36] http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf

## 2.3 Study Assumptions and Methodology

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

### 2.3.1 Study Horizon and Years

The studies that comply with TPL-001-4 were conducted for both the near-term[37] (2018-2022) and longer-term[38] (2023-2027) per the requirements of the reliability standards. Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2019, 2022 and 2027.

### 2.3.2 Transmission Assumptions

#### 2.3.2.1 *Transmission Projects*

The study included existing transmission in service and the expected future projects that have been approved by the ISO but are not yet in service. Refer to Table 7.1-1 and Table 7.1-1 of chapter 7 (Transmission Project Updates) for the list of previously-approved projects that are not yet in service. Projects with potential significant scope changes were not modeled in the starting base case. Previously-approved transmission projects that were not included in the base cases are identified below in the local area assessments.

Also included in the study cases were generation interconnection related transmission projects that were included in executed Large Generator Interconnection Agreements (LGIA) for generation projects included in the base case.

#### 2.3.2.2 *Reactive Resources*

Existing and new reactive power resources were modeled in the study base cases to ensure realistic voltage 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 compensators 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).[39]

[37] System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.
[38] System peak load conditions for one of the years and the rationale for why that year was selected.
[39] 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.

#### 2.3.2.3 *Protection System*

To help ensure reliable operations, many special protection systems (SPS), safety nets, UVLS and UFLS schemes have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing SPS, safety nets, and UVLS included in the study are listed in Appendix A.

#### 2.3.2.4 *Control Devices*

Several control devices were modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas;
- Static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations;
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects (note the PDCI Upgrade Project – to 3220 MW – was approved in 2017); and,
- Imperial Valley flow controller; (e.g., phase shifting transformer).

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 secure website.

### 2.3.3 Load Forecast Assumptions

#### 2.3.3.1 *Energy and Demand Forecast*

The assessment used the California Energy Demand Updated Forecast, 2017-20127 adopted by California Energy Commission (CEC) on January 25, 2017 using the Mid Case LSE and Balancing Authority Forecast spreadsheet of January 12, 2017.

During 2016, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2015 IEPR final report, adopted on February 15, 2017, based on the IEPR record and in consultation with the CPUC and the ISO, recommended using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

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 broader geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

The California Energy Demand Updated Forecast 2017-2027 includes Peak-Shift Scenario Analysis and states the following with respect to the use of results of this analysis in the ISO TPP studies:

> *"The results of the final adjusted managed peak scenario analysis can be used by the California ISO in TPP studies to review previously -approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in identifying new needs triggering new transmission projects, given the preliminary analysis. More complete analyses will be developed for IEPR forecasts once full hourly load forecasting models are developed."*[40]

In the 2017-2018 transmission planning process, the ISO used the CEC energy and demand forecast for the base scenario analysis identified in section 2.3.8.1. The ISO conducts sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, these and other forecasting uncertainties were taken into account in the sensitivity studies identified in section 2.3.8.2. The ISO has continued to work with the CEC on the hourly load forecast issue during the development of 2017 IEPR.

### 2.3.3.2 *Self-Generation*

Peak demand in the CEC demand forecast was reduced by projected impacts of self-generation serving on-site customer load. The self-generation was further categorized as PV and non-PV. Statewide, self-generation was projected to reduce peak load by more than 8,078 MW in the mid case by 2027. In 2017-2018 transmission planning process base cases, the PV component of self-generation was modeled as discrete elements. Self-generation peak impacts for PG&E, SCE and SDG&E planning areas are shown in Table 2.3-1.

[40] CEC Staff Report, "California Energy Demand Updated Forecast, 2017-2027," January 2017, http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215275_20170112T135223_California_Energy_Demand_Updated_Forecast_20172027.pdf , at p. 51.

Table 2.3-1: PG&E, SCE & SDG&E Planning Areas PV Self-Generation Peak Impacts (MW)

| | CEDU 2016 Mid Demand | | |
|---|---|---|---|
| | PG&E | SCE | SDG&E |
| 2018 | 1,001 | 823 | 304 |
| 2019 | 1,068 | 902 | 327 |
| 2020 | 1,141 | 981 | 348 |
| 2021 | 1,226 | 1,074 | 372 |
| 2022 | 1,328 | 1,186 | 400 |
| 2023 | 1,447 | 1,315 | 431 |
| 2024 | 1,581 | 1,458 | 464 |
| 2025 | 1,728 | 1,616 | 500 |
| 2026 | 1,886 | 1,787 | 537 |
| 2027 | 2,050 | 1,960 | 574 |

The CEC self-generation information is available on the CEC website at: http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/mid_demand_case.php .

PV Self-generation installed capacities by PTO are shown in Table 2.3-2. Output of the self-generation PV were selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Table 2.3-2: PV self-generation installed capacity by PTO[41]

| PTO | Forecast Climate Zone | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | Central Coast | 226 | 226 | 266 | 290 | 318 | 350 | 385 | 423 | 464 | 505 |
| | Central Valley | 636 | 636 | 721 | 776 | 841 | 914 | 994 | 1081 | 1174 | 1267 |
| | Greater Bay Area | 876 | 876 | 1054 | 1164 | 1290 | 1433 | 1590 | 1760 | 1941 | 2122 |
| | North Coast | 266 | 266 | 321 | 354 | 391 | 433 | 480 | 529 | 582 | 635 |
| | North Valley | 150 | 150 | 166 | 176 | 188 | 203 | 219 | 237 | 257 | 277 |
| | Southern Valley | 749 | 749 | 817 | 862 | 917 | 982 | 1055 | 1137 | 1226 | 1316 |
| | PG&E Total | 2903 | 2903 | 3343 | 3622 | 3944 | 4315 | 4724 | 5166 | 5644 | 6121 |
| SCE | Big Creek East | 231 | 243 | 254 | 269 | 288 | 310 | 334 | 361 | 391 | 420 |
| | Big Creek West | 166 | 180 | 193 | 214 | 239 | 269 | 302 | 339 | 380 | 421 |
| | Eastern | 526 | 582 | 634 | 697 | 770 | 851 | 940 | 1038 | 1142 | 1247 |
| | LA Metro | 902 | 1003 | 1105 | 1234 | 1386 | 1558 | 1747 | 1958 | 2182 | 2406 |
| | Northeast | 358 | 393 | 427 | 467 | 512 | 562 | 616 | 676 | 740 | 803 |
| | SCE Total | 2183 | 2400 | 2614 | 2881 | 3195 | 3550 | 3939 | 4373 | 4834 | 5296 |
| SDG&E | SDG&E | 806 | 867 | 927 | 997 | 1077 | 1164 | 1257 | 1356 | 1459 | 1563 |

### 2.3.4 Generation Assumptions

Generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels for the peak demand bases cases. Qualifying facilities (QFs) and self-generating units were modeled based on their historical generating output levels. Renewable generation was dispatched as identified in section 2.3.4.2.

#### 2.3.4.1 *Generation Projects*

In addition to generators that are already in-service, new generators were modeled in the studies depending on the status of each project.

[41] Based on self-generation PV calculation spreadsheet provided by CEC.

### 2.3.4.2 *Renewable Generation*

The CPUC policy direction to the ISO regarding renewable generation portfolios in the 2017-2018 transmission planning cycle was via an Assigned Commissioners Ruling[42] in February, 2017. In that Assigned Commissioners Ruling, the CPUC recommended that the ISO re-use the "33% 2025 Mid AAEE" RPS portfolio – which was also used in the 2015-16 TPP and again in the 2016-2017 studies – as the base case renewable resource portfolio in the 2017-18 TPP studies. As indicated in the Assigned Commissioners Ruling, the ISO also supplemented the scenario with information regarding contracted RPS projects that had begun construction since May 2016.

Generation included in this year's baseline scenario as described in Section 24.4.6.6 of the ISO Tariff was also included in the 10-year Planning Cases. Given the data availability, generic dynamic data may be used for the future generation.

**Renewable generation dispatch**

The ISO has done a qualitative and quantitative assessment of hourly Grid View renewable output for stressed conditions during hours and seasons of interest. Available data of pertinent hours was catalogued by renewable technology and location on the grid. The results of active power output differ somewhat between locations and seasons as follows. Reactive limits of renewable generation were as specified by Qmax and Qmin, which rely upon technology of the generation and may change as a function of active power output and power factor specified. Table 2.3-3, Table 2.3-4, Table 2.3-5, and Table 2.3-6 summarize the renewable output in each of the PTO areas.

Table 2.3-3: Summary of renewable output in PG&E

| All years | Biomass/Biogas/Geothermal | Solar PV, ST | Wind | Stressed case |
|---|---|---|---|---|
| Sum Min Load | NQC | 0 | Pmax | High Output |
| Sum Off-Peak | NQC | Pmax | Pmax | High Output |
| Sum Partial-Peak | NQC | 0 | 0 | Low Output |
| Sum Peak | NQC | 25%xPmax | 33%xPmax | Low Output |
| Winter Peak | NQC | 0 | 16.6%xPmax | Low Output |

[42] "Assigned Commissioner's Ruling Adopting Assumptions and One Scenario for Use in Long-Term Planning in 2017," *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements*, Proceeding No. R.16-02-007, Febraury 28, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M176/K948/176948479.PDF.

Table 2.3-4: Summary of renewable output in SCE

| | Biomass/Biogas/Geothermal | Solar PV, ST | Wind | Stressed case |
|---|---|---|---|---|
| Sum Min Load | NQC | 0 | 93%xPmax | High Output |
| Sum Off-Peak | NQC | 93%xPmax | 93%xPmax | High Output |
| Sum Partial- Peak | NQC | TBD | TBD | Low output |
| Sum Peak | NQC | 36%xPmax | 0 | Low Output |

Table 2.3-5: Summary of renewable output in SDG&E

| All years | Biomass/Biogas/Geothermal | Solar PV, ST | Wind | Stressed case |
|---|---|---|---|---|
| Sum Min Load | NQC | 0 | Pmax | High Output |
| Sum Off-Peak | NQC | 81%xPmax | 96%xPmax | High Output |
| Sum Peak | NQC | 55%xPmax | 33%xPmax | Low Output |

Table 2.3-6: Summary of renewable output in VEA

| All years | Biomass/Biogas/Geothermal | Solar PV, ST | Wind | Stressed case |
|---|---|---|---|---|
| Sum Min Load | NQC | 0 | N/A | High Output |
| Sum Off-Peak | NQC | 97%xPmax | N/A | High Output |
| Sum Peak | NQC | 47%xPmax | N/A | Low Output |

#### 2.3.4.3 *Thermal generation*

For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). The ISO also relies on other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A2-1 of Appendix A lists new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

#### 2.3.4.4 *Hydroelectric Generation*

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a recent drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. The Big Creek area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards.

#### 2.3.4.5 *Generation Retirements*

Existing generators that have been identified as retiring are listed in table A2-1 of Appendix A. These generators along with their step-up transformer banks are modeled as out of service starting in the year they are assumed to be retired.

In addition to the identified generators the following assumptions were made for the retirement of generation facilities.

- Nuclear Retirements – Diablo Canyon was modeled offline based on the OTC compliance dates,
- Once Through Cooled (OTC) Retirements – As identified in section 2.3.1.
- Renewable and Hydro Retirements – Assumed these resource types stay online unless there is an announced retirement date.
- Other Retirements – Unless otherwise noted, assumed retirement based resource age of 40 years or more.

#### 2.3.4.6 *OTC Generation*

Modeling of the once-through cooled generating units, shown in Table 2.3-7, followed the compliance schedule from the State Water Resources Control Board's (SWRCB) policy on OTC plants with the following exceptions:

- generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology,; and
- all other OTC generating units were modeled off line beyond their compliance dates.

Table 2.3-7: Once-through cooled generation in the California ISO Balancing Authority Area

| Area | Generating Facility (Total Plant MW) | Owner | Unit | State Water Resources Control Board (SWRCB) Compliance Date | Net Qualifying Capacity (NQC) (MW) | Notes |
|---|---|---|---|---|---|---|
| Humboldt LCR Area | Humboldt Bay (135 MW) | PG&E | 1 | 12/31/2010 | 52 | Retired 135 MW (Mobile 2&3 non-OTC) and repowered with 10 CTs (163 MW) - (July 2010) |
| | | | 2 | 12/31/2010 | 53 | |
| Greater Bay Area LCR | Contra Costa (674 MW) | GenOn | 6 | 12/31/2017 | 337 | Replaced by Marsh Landing power plant (760 MW) – (May 2013) |
| | | | 7 | 12/31/2017 | 337 | |
| | Pittsburg (1,311 MW) Unit 7 is non-OTC | GenOn | 5 | 12/31/2017 | 312 | On October 3, 2016, NRG Delta sent a letter to the CPUC to notify that it planned to shut down permanently retire Units 5 and 6 as early as January 1, 2017. NRG Delta also notified the SWRCB that it permanently ceased once-through-cooling operation for these units by the end of the day of December 31, 2016. All three units, including Unit 7, have been ceased operation. |
| | | | 6 | 12/31/2017 | 317 | |
| | Potrero (362 MW) | GenOn | 3 | 10/1/2011 | 206 | Retired 362 MW (Units 4, 5 & 6 non-OTC) |
| Central Coast (non-LCR area)<br>*Non-LCR area has no local capacity requirements | Moss Landing (2,530 MW) | Dynegy | 1 | 12/31/2020* | 510* | * Per Dynegy's Settlement Agreement with the SWRCB, executed on October 9, 2014, the Moss Landing generating units will have until December 31, 2020 to be brought into compliance. Dynegy will pursue Track 2 compliance for Units 1 and 2 by installing technology control and implementing operational control to reduce impingement mortality and entrainment. In its January 5, 2017 letter to the SWRCB, Dynegy indicated that it no longer intended to achieve Track 2 compliance for Units 6 and 7 and instead intended to retire both units. Dynegy stated |
| | | | 2 | 12/31/2020* | 510* | |
| | | | 6 | 12/31/2020 | 754 | |
| | | | 7 | 12/31/2020 | 756 | |

| Area | Generating Facility (Total Plant MW) | Owner | Unit | State Water Resources Control Board (SWRCB) Compliance Date | Net Qualifying Capacity (NQC) (MW) | Notes |
|---|---|---|---|---|---|---|
| | | | | | | that it shut down Units 6 and 7 on January 1, 2017. |
| | Morro Bay (650 MW) | Dynegy | 3 | 12/31/2015 | 325 | Retired 650 MW (February 5, 2014) |
| | | | 4 | 12/31/2015 | 325 | |
| | Diablo Canyon (2,240 MW) | PG&E | 1 | 12/31/2024 | 1122 | On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2025. |
| | | | 2 | 12/31/2024 | 1118 | |
| Big Creek-Ventura LCR Area | Mandalay (560 MW) | GenOn | 1 | 12/31/2020 | 215 | Unit 3 is non-OTC |
| | | | 2 | 12/31/2020 | 215 | |
| | Ormond Beach (1,516 MW) | GenOn | 1 | 12/31/2020 | 741 | |
| | | | 2 | 12/31/2020 | 775 | |
| Los Angeles (LA) Basin LCR Area | El Segundo (670 MW) | NRG | 3 | 12/31/2015 | 335 | Replaced by El Segundo Power Redevelopment (560 MW) – (August 2013) |
| | | | 4 | 12/31/2015 | 335 | Unit 4 was retired on December 31, 2015. |
| | Alamitos (2,011 MW) | AES | 1 | 12/31/2020 | 175 | On November 19, 2015, the CPUC, with Decision 15-11-041, approved 640 MW combined-cycle generating facility repowering project for AES Alamitos Energy, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland |
| | | | 2 | 12/31/2020 | 175 | |
| | | | 3 | 12/31/2020 | 332 | |
| | | | 4 | 12/31/2020 | 336 | |
| | | | 5 | 12/31/2020 | 498 | |
| | | | 6 | 12/31/2020 | 495 | |
| | | AES | 1 | 12/31/2020 | 226 | |

| Area | Generating Facility (Total Plant MW) | Owner | Unit | State Water Resources Control Board (SWRCB) Compliance Date | Net Qualifying Capacity (NQC) (MW) | Notes |
|---|---|---|---|---|---|---|
| | Huntington Beach (452 MW) | | 2 | 12/31/2020 | 226 | On November 19, 2015, the CPUC, with Decision 15-11-041, approved a repowering project for a 644 MW combined-cycle generating facility for AES Huntington Beach, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland, |
| | | | 3 | 12/31/2020 | 227 | Retired 452 MW and converted to synchronous condensers (2013). Modeled as off-line in the post 2017 studies as contract expires. |
| | | | 4 | 12/31/2020 | 227 | |
| | Redondo Beach (1,343 MW) | AES | 5 | 12/31/2020 | 179 | |
| | | | 6 | 12/31/2020 | 175 | |
| | | | 7 | 12/31/2020 | 493 | |
| | | | 8 | 12/31/2020 | 496 | |
| | San Onofre (2,246 MW) | SCE/ SDG&E | 2 | 12/31/2022 | 1122 | Retired 2246 MW (June 2013) |
| | | | 3 | 12/31/2022 | 1124 | |
| San Diego/I.V. LCR Area | Encina (946 MW) | NRG | 1 | 12/31/2017 | 106 | The Encina plant is being replaced by the 500 MW Carlsbad Energy Center. NRG has indicated that Encina Unit 1 would retire early (by March 31, 2017 at the latest) to allow for the construction of the Carlsbad Energy Center interconnection facilities. |
| | | | 2 | 12/31/2017 | 103 | |
| | | | 3 | 12/31/2017 | 109 | |
| | | | 4 | 12/31/2017 | 299 | |
| | | | 5 | 12/31/2017 | 329 | |
| | South Bay (707 MW) | Dynegy | 1-4 | 12/31/2011 | 692 | Retired 707 MW (CT non-OTC) – (2010-2011) |

### 2.3.4.7 *LTPP Authorization Procurement*

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-8 provides the local capacity resource additions and the study year in which the amounts were first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 2.3-9 provides details of the study assumptions using the utilities' procurement activities to date, as well as the ISO's assumptions for potential preferred resources for the San Diego area.

Table 2.3-8: Summary of 2012 LTPP Track 1 & 4 Authorized Procurement

| **LCR Area** | **LTTP Track-1** | | **LTTP Track-4**[43] | |
|---|---|---|---|---|
| | **Amount (MW)(1)** | **Study year in which addition is to be first modeled** | **Amount (MW) (1)** | **Study year in which addition is to be first modeled** |
| Moorpark Sub-area | 290 | 2021 | 0 | N/A |
| West LA Basin / LA Basin | 1400-1800 | 2021 | 500-700 | 2021 |
| San Diego | 308 | 2018 | 500-800 | 2018 |

Notes: Amounts shown are total including gas-fired generation, preferred resources and energy storage

[43] CPUC Decision for LTPP Track 4 (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF)

Table 2.3-9: Summary of 2012 LTPP Track 1 & 4 Procurement Activities to date

| | LTPP EE (MW) | Behind the Meter Solar PV (NQC MW) | Storage 4-hr (MW) | Demand Response (MW) | Conventional resources (MW) | Total Capacity (MW) |
|---|---|---|---|---|---|---|
| SCE's procurement for the Western LA Basin[44] | 124.04 | 37.92 | 263.64 | 5 | 1,382 | 1,812.60 |
| SCE's procurement for the Moorpark Sub-area[45] | 6.00 | 5.66 | 0.50 | 0 | 262 | 274.16 |
| SDG&E's procurement | 22.4* | 0 | 25**-84* | 33.6* | 800[46] | 881-940 |

Notes:

* Proxy preferred resource and energy storage assumptions are based on the maximum total amount of 140 MW that SDG&E is soliciting based on its 2016 RFO for Local Capacity Requirements Decision established by the CPUC via D.14-03-004 (the "Track 4" Decisions). These were updated upon SDG&E's filing of final procurement selection for preferred resources and energy storage at the CPUC later in 2016 time frame.

** Based on the CPUC draft Scenarios and Assumptions for the 2016 LTPP and the 2016-2017 Transmission Planning Process, 25 MW was assumed initially for the energy storage for San Diego and this amount can be increased (up to the net amount of the ceiling for preferred resources and energy storage subtracting other assumptions for LTPP related for preferred resources) if needed.

*** Pio Pico (300 MW) and Carlsbad Energy Center (500 MW) were approved by the CPUC as part of SDG&E-selected procurement for LTPP Tracks 1 and 4.

### 2.3.5 Preferred Resources

According to tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the ISO received demand response and energy storage information for consideration in planning studies from Pacific Gas

[44] SCE-selected RFO procurement for the Western LA Basin was approved by the CPUC with PPTAs per Decision 15-11-041, issued on November 24, 2015.
[45] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area is currently at the CPUC for review and consideration.
[46] The CPUC, in Decisions 14-02-016 and 15-05-051 approved PPTAs for the Pio Pico and Carlsbad Energy Center projects.

& Electric (PG&E). PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the Unified Planning Assumptions and 2017-2018 study plan.

### Methodology

The ISO issued a paper[47] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan as an alternative to the conventional transmission or generation solution. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-Area Local Capacity Alternative Study released on August 16, 2017.[48] In addition, then ISO has developed a methodogy as discussed in section 6.6 for examing the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds on and expands the analysis framework of preferred resources.

As in past planning cycles, the reliability assessments in the current planning cycle considered a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the portfolio provided by the CPUC and CEC, and a mix of proxy preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

For each planning area, reliability assessments are initially performed using preferred resources other than DR to identify reliability concerns in the area. If reliability concerns are identified in the initial assessment, additional rounds of assessments are performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis as described in September 4, 2013 ISO paper – is performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including diurnal variation in the case of solar DG and use or energy limitation in the case of demand response and energy storage.

[47] http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

[48] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

### Demand Response

In reliability studies, only capacity from DR programs that can be relied upon to mitigate "first contingencies", as described in the 2012 LTPP Track 4 planning assumptions, are counted. DR that can be relied upon to mitigate post first contingencies in local reliability studies participates in, and is dispatched from, the ISO market in sufficiently less time than 30 minutes[49] from when it is called upon.

There is uncertainty as to what amount of DR can be projected to meet this criteria within the TPP planning horizon given that few current programs meet this criteria and the current DR Rulemaking R.13-09-011 expects to restructure DR programs to better meet ISO operational needs and has already produced one major policy decision towards that goal.[50] The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but ISO has several tasks it must complete in order to make integration of DR possible.

The DR Load Impact Reports filed with the CPUC on April 1, 2016, and other supply-side DR procurement incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. Table 2.3-10 describes the total supply-side DR capacity assumptions.

[49] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

[50] Commission Decision 14-03-026 approved the bifurcation of DR programs into two categories: Supply DR (DR that is integrated into ISO markets and dispatched when and where needed) and Load-Modifying DR (DR that is not integrated into ISO markets. This decision determined that bifurcation will occur by 2017.

Table 2.3-10: Existing DR Capacity Range in Local Area Reliability Studies

| DR not embedded in IEPR demand forecast (values in MW): | PG&E | SCE | SDG&E | All IOUs | Assumed Market Participation | Assumed to respond within 30 minutes |
|---|---|---|---|---|---|---|
| Base Interruptible | 255 | 607 | 1.4 | 863.4 | RDRR | Yes |
| Agricultural Pumping Interruptible | - | 63 | - | 63 | RDRR | Yes |
| AC Cycling Residential | 54 | 218 | 11.5 | 277 | PDR | Yes |
| AC Cycling Non-Residential | 1 | 40 | 3.1 | 44.1 | PDR | Yes |
| CPB | 120 | 141 | 12.2 | 263 | PDR | No |
| DBP | 0 | 0 | 0 | 0 | PDR | No |
| AMP(DRC) | 0 | 0 | - | 0 | PDR | No |
| SCE LCR RFO | - | 5 | - | 5 | RDRR | Yes |
| DRAM | - | - | - | 124.6 | PDR | No |

Given the uncertainty as to what amount of DR can be relied upon for mitigating first contingencies, the ISO's 2014-2015 TPP Base local area reliability studies examined two scenarios, one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions. Similarly, the ISO will examine two scenarios in the 2016-2017 TPP, one using the updated 20 minute DR data from SCE and the other consistent with the 2016 LTPP DR assumptions.

DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs. The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.

Table 2.3-11 shows the factors that were applied to the DR projections to account for avoided distribution losses.

Table 2.3-11: Factors to Account for Avoided Distribution Losses

| | **PG&E** | **SCE** | **SDG&E** |
|---|---|---|---|
| Distribution loss factors | 1.067 | 1.051 | 1.071 |

**Energy Storage**

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the ISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target.

As the 2016-2017 TPP studies identify transmission constraints in the local areas, the ISO will identify the effective busses that the storage capacity identified in the table below can be distributed amongst within the local area as potential development sites. Table 2.3-12 describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage mandated by D.13-10-040. These storage capacity amounts will not be included in the initial reliability analysis. The storage capacity amounts will be used as potential mitigation in those planning areas where reliability concerns have been identified.

Table 2.3-12: Storage Operation Attributes

| Values are MW in 2024 | Transmission-connected | Distribution-connected# | Customer- side |
|---|---|---|---|
| Total Installed Capacity | 700 | 425 | 279** |
| Amount providing capacity in power flow studies | 560 * | 170 * | 135@ |
| Amount providing flexibility | 700 | 212.5 | 135 |
| Amount with 2 hours of storage | 280 | 170 | 100 |
| Amount with 4 hours of storage | 256 ^ | 170 | 135 |
| Amount with 6 hours of storage | 124 ^ | 85 | 0 |

Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.

# Distribution-connected energy storage is assumed to provide 50% of its installed capacity for modeling in power flow studies

* This reflects a 50 % derating of capacity value of 2 hour storage due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.

@ This reflects 135 MW from SCE 2014 LCR RFO

^ This amount was adjusted down to reflect the assumption that the 40 MW Lake Hodges storage project satisfies the storage target for a portion of SDG&E's share of the target.

** SCE procured 164 MW of BTM ES via its 2014 LCR RFO, exceeding its 85 MW BTM ES 2020 target; these 164 MW added to PG&E's and SDG&E's BTM ES target (85 MW and 30 MW respectively) results in 279 MW of BTM ES expected to be online by 2020.

### 2.3.6 Firm Transfers

Power flow on the major internal paths and paths that cross balancing authority boundaries represents the transfers modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.3-13 lists the capability and power flows modeled in each scenario on these paths in the northern area assessment[51].

Table 2.3-13: Major paths and power transfer ranges in the Northern California assessment[52]

| Path | Transfer Capability/SOL (MW) | Scenario in which Path will be stressed |
|---|---|---|
| Path 26 (N-S) | 4000[53] | Summer Peak |
| PDCI (N-S) | 3100[54] | |
| Path 66 (N-S) | 4800[55] | |
| Path 15 (N-S) | -5400[56] | Summer Off Peak |
| Path 26 (N-S) | -3000 | |
| Path 66 (N-S) | -3675 | Winter Peak |

For the summer off-peak cases in the northern California study, Path 15 flow was adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 was adjusted between 1800 MW south-to-north and 1800 MW north-to-south to maintain the stressed Path 15 as well as to balance the loads and resources in northern California. Some light load cases model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit.

Similarly, Table 2.3-14 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

51 These path flows will be modeled in all base cases.

52 The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

53 May not be achievable under certain system loading conditions.

54 Note the PDCI Upgrade Project – to 3220 MW – was approved in 2017 and will be used in future planning cycles.

55 The Path 66 flows was modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

56 May not be achievable under certain system loading conditions

Table 2.3-14: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

| Path | Transfer Capability/SOL (MW) | Target Flows (MW) | Scenario in which Path will be stressed, if applicable |
|---|---|---|---|
| Path 26 (N-S) | 4,000 | 4,000 | Summer Peak |
| PDCI (N-S) | 3220 | 3220 | |
| West of River (WOR) | 11,200 | 5,000 to 11,200 | N/A |
| East of River (EOR) | 10,100 | 4,000 to 9,600 | N/A |
| San Diego Import | 2,850 | 2,400 to 3,500 | Summer Peak |
| SCIT | 17,870 | 15,000 to 17,870 | Summer Peak |
| Path 45 (N-S) | 400 | 0 to 250 | Summer Peak |
| Path 45 (S-N) | 800 | 0 to 300 | Off Peak |

### 2.3.7 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, were modeled in the studies.

Please refer to the website: http://www.caiso.com/thegrid/operations/opsdoc/index.html, for the list of publicly available Operating Procedures.

### 2.3.8 Study Scenarios

#### 2.3.8.1 *Base Scenarios*

The main study scenarios cover critical system conditions driven by several factors such as:

*Generation:*

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.3.4.

*Demand Level:*

Since most of the ISO footprint is a summer peaking area, summer peak conditions were evaluated in all study areas. However, winter peak, spring off-peak, summer off-peak or summer partial-peak were also be studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which were studied for both the summer and winter peak conditions. Table 2.3-15 lists the scenarios that were conducted in this planning cycle.

*Path flows:*

For local area studies, transfers on import and monitored internal paths will be modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths will be stressed as described in section 2.3.4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable. Table 2.3-15 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

Table 2.3-15: Summary of study areas, horizon and peak scenarios for the reliability assessment

| Study Area | Near-term Planning Horizon | | Long-term Planning Horizon |
|---|---|---|---|
| | 2019 | 2022 | 2027 |
| Northern California (PG&E) Bulk System | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak<br>Summer Partial Peak<br>Spring Off-Peak |
| Humboldt | Summer Peak<br>Winter Peak<br>Spring Light Load | Summer Peak<br>Winter Peak<br>Spring Off-Peak | Summer Peak<br>Winter Peak |
| North Coast and North Bay | Summer Peak<br>Winter peak<br>Spring Light Load | Summer Peak<br>Winter Peak<br>Spring Off-Peak | Summer Peak<br>Winter peak |
| North Valley | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| Central Valley (Sacramento, Sierra, Stockton) | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| Greater Bay Area | Summer Peak<br>Winter peak<br>- (SF & Peninsula)<br>Spring Light Load | Summer Peak<br>Winter peak<br>- (SF & Peninsula)<br>Spring Off-Peak | Summer Peak<br>Winter peak<br>- (SF Only) |
| Greater Fresno | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| Kern | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| Central Coast & Los Padres | Summer Peak<br>Winter Peak<br>Spring Light Load | Summer Peak<br>Winter Peak<br>Spring Off-Peak | Summer Peak<br>Winter Peak |
| Southern California Bulk transmission system | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SCE Metro Area | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SCE Northern Area | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SCE North of Lugo Area | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SCE East of Lugo Area | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |

| Study Area | Near-term Planning Horizon | | Long-term Planning Horizon |
|---|---|---|---|
| | 2019 | 2022 | 2027 |
| SCE Eastern Area | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SDG&E main transmission | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| SDG&E sub-transmission | Summer Peak<br>Spring Light Load | Summer Peak<br>Spring Off-Peak | Summer Peak |
| Valley Electric Association | Summer/Winter Peak<br>Spring Light Load | Summer/Winter Peak<br>Spring Off-Peak | Summer/Winter Peak |

### 2.3.8.2 *Sensitivity study cases*

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2017-2018 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-16. The sensitivity scenarios are to assess impacts of specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.3-16: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

| Sensitivity Study | Near-term Planning Horizon | | Long-Term Planning Horizon |
|---|---|---|---|
| | 2019 | 2022 | 2027 |
| Summer Peak with high CEC forecasted load and peak shift | | PG&E Local Areas<br>SCE Metro<br>SCE Northern<br>SDG&E Main<br>SDG&E Sub-transmission | - |
| CEC peak-shift sensitivity | PG&E Local Areas<br>SCE Metro<br>SCE Northern<br>SDG&E Main<br>SDG&E Sub-transmission | - | PG&E Bulk<br>PG&E Local Areas<br>SCE Metro<br>SCE Northern<br>SDG&E Main<br>SDG&E Sub-transmission |
| Off-peak with maximum PV Output | | - PG&E Bulk<br>Southern California Bulk | |
| Summer Peak with heavy renewable output and minimum gas generation commitment | - | PG&E Bulk<br>PG&E Local Areas<br>Southern California Bulk<br>SCE Northern<br>SCE North of Lugo<br>SCE East of Lugo<br>SCE Eastern<br>SCE Metro<br>SDG&E Main | - |
| Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition) | - | VEA Area | - |

| Sensitivity Study | Near-term Planning Horizon | | Long-Term Planning Horizon |
|---|---|---|---|
| | 2019 | 2022 | 2027 |
| Summer Peak with low hydro output | - | SCE Northern Area | - |
| Summer Peak with heavy northbound flow north of the SONGS switchyard | | SDG&E Main | |
| Retirement of QF Generations | - | - | PG&E Local Areas |

### 2.3.9 Contingencies

In addition to the system under normal conditions (P0), the following contingencies were evaluated as part of the study. These contingencies lists have been made available on the ISO secured website.

**Single contingency (Category P1)**

The assessment considered all possible Category P1 contingencies based upon the following:

- Loss of one generator (P1.1)[57]
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)

**Single contingency (Category P2)**

The assessment considered all possible Category P2 contingencies based upon the following:

- Loss of one transmission circuit without a fault (P2.1)
- Loss of one bus section (P2.2)

[57] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

- Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

**Multiple contingency (Category P3)**

The assessment considered the Category P3 contingencies with the loss of a ***generator unit*** followed by system adjustments and the loss of the following:

- Loss of one generator (P3.1)[58]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

**Multiple contingency (Category P4)**

The assessment considered the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:

- Loss of one generator (P4.1)
- Loss of one transmission circuit (P4.2)
- Loss of one transformer (P4.3)
- Loss of one shunt device (P4.4)
- Loss of one bus section (P4.5)
- Loss of a bus-tie-breaker (P4.6)

**Multiple contingency (Category P5)**

The assessment considered the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:

- Loss of one generator (P5.1)
- Loss of one transmission circuit (P5.2)
- Loss of one transformer (P5.3)

[58] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

- Loss of one shunt device (P5.4)
- Loss of one bus section (P5.5)

**Multiple contingency (Category P6)**

The assessment considered the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

**Multiple contingency (Category P7)**

The assessment considered the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure[59] (P7.1)
- Loss of a bipolar DC lines (P7.2)

**Extreme Event contingencies (TPL-001-4)**

As a part of the planning assessment the ISO assessed Extreme Event contingencies per the requirements of TPL-001-4; however the analysis of Extreme Events have not been included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

### 2.3.10 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.

#### 2.3.10.1 *Study Tools*

The GE PSLF program is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for post-transient and transient stability studies. PowerGem TARA was used for steady state contingency analysis. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories P1-P7 outages of equipment at the voltage level 60 through 230 kV. In the bulk system assessments, governor power flow was used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

[59] Excludes circuits that share a common structure or common right-of-way for 1 mile or less.

#### 2.3.10.2 *Technical Studies*

The section explains the methodology that will be used in the study:

**Power Flow Contingency Analysis**

The ISO performed power flow contingency analyses based on the ISO Planning Standards[60] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid and with select contingencies outside of the ISO controlled grid. The transmission system was evaluated under normal system conditions NERC Category P0 (TPL 001-4), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-4) contingencies against emergency ratings and emergency voltage range.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[61]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases are updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

The contingency analysis simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses included the impact of subsequent tripping of transmission elements where relay loadability limits are exceeded and generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations unless corrective action plan is developed to address the loading and voltages concerns.

Power flow studies are performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities below 200 kV that must meet PRC-023 to prevent potential cascade tripping that may occur when protective relay settings limit transmission load ability.

**Post Transient Analyses**

Post Transient analyses was conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the bulk system assessments and if there are thermal overloads on the bulk system.

**Post Transient Voltage Stability Analyses**

[60] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

[61] Per California ISO Planning standards Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

Post Transient Voltage stability analyses was conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

### Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis using WECC standards of 5% voltage deviation for “N-1” contingencies and 10% voltage deviation for “N-2” contingencies.

### Voltage Stability and Reactive Power Margin Analyses

As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category P0) and for single contingencies (Category P1). For other contingencies (Category P2-P7), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, was used for the analyses in the ISO controlled grid. According to the guideline, load is increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and studied to determine if the system has sufficient reactive margin. This study was conducted in the areas that have voltage and reactive concerns throughout the system.

### Transient Stability Analyses

Transient stability analyses was also conducted as part of bulk area system assessment and local for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per ISO Planning Standards.

# 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.

Table 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. In addition, 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 the 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 and the flows can be either south-to-north or north-to-south under peak conditions. 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, which are the 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 spring off-peak (S-N) flow scenarios were analyzed as well as a spring minimum load conditions and partial peak scenarios. 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. The ISO-secured website lists the contingencies that were performed as a 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 2019, 2022 and 2027; spring off-peak cases for 2022 and 2027; spring light load case for 2019; and summer partial peak case for 2027. In addition, 3 sensitivity cases were studied: the 2022 Summer Peak case with high renewable and low gas generation output, 2022 Summer Peak Shift case and 2022 Spring off-Peak case with high solar PV output. 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. Also, extreme events such 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. The total generation in each of the local planning areas within the PG&E system are provided in Section 2.5.

Since the studies analyzed the most critical conditions, the flows on the 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. Due to retirement of several large OTC power plants in northern California, flow on Path 26 between northern and southern California was modeled in the 2022 and 2027 cases significantly below its 4000 MW north-to-south rating. Table 2.4-2 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4-2: Major import flows and Northern California Hydro generation level for the northern area bulk study

| BASE CASE | Scenario Type | Description | COI | Path 15 | Path 26 | PDCI | N.Cal Hydro |
|---|---|---|---|---|---|---|---|
| PGE-Bulk-2019-SP | Base Line | 2019 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 4800 N-S | 1310 N-S | 3670 N-S | 3100 N-S | 80% |
| PGE-Bulk-2019-ML | Base Line | 2019 spring light load conditions. Light load time - hours between 2:00 and 4:00 | 800 N-S | 5 S-N | 1060 N-S | 2000 N-S | 13% |
| PGE-Bulk-2022-SP | Base Line | 2022 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 4750 N-S | 930 N-S | 3100 N-S | 3200 N-S | 80% |
| PGE-Bulk-2022-SpOP | Base Line | 2022 spring off-peak load conditions. Off-peak load time - weekend morning | 3470 S-N | 5290 S-N | 170 S-N | 0 | 65% |
| PGE-Bulk-2027-SP | Base Line | 2027 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 4800 N-S | 1000 N-S | 1040 N-S | 3200 N-S | 80% |
| PGE-Bulk-2027-SPP | Base Line | 2027 Summer partial peak. hours between 20:00 and 21:00 | 4760 N-S | 2090 S-N | 2910 S-N | 3200 N-S | 80% |
| PGE-Bulk-2027-SpOP | Base Line | 2027 spring off-peak load conditions. Off-peak load time - weekend morning | 3410 S-N | 4240 S-N | 1160 S-N | 0 | 66% |
| PGE-Bulk-2022-SP-HiRenew | Sensitivity | 2022 Summer peak load conditions with high renewables dispatch sensitivity | 4800 N-S | 1030 N-S | 3290 N-S | 3200 N-S | 80% |
| PGE-Bulk-2027-SP-PS | Sensitivity | 2027 Summer peak load conditions with peak shift sensitivity | 4770 N-S | 370 S-N | 1010 S-N | 3200 N-S | 86% |
| PGE-Bulk-2022-SpOP-maxPV | Sensitivity | 2022 spring off-peak load conditions with maximum photovoltaic output | 880 S-N | 3860 S-N | 2210 S-N | 0 | 20% |

All power flow cases included certain amount of renewable resources, which was dispatched at different levels depending on the case studied. The assumptions on the generation installed capacity and the output are summarized in Table 2.4-3.

Table 2.4-3. Generation Assumptions – PG&E Bulk System

| BASE CASE | Scenario Type | Description | Battery Storage | Solar | | Wind | | Hydro | | Thermal: incl. geo, nuclear, bio | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Installed | Dispatch | Installed | Dispatch | Installed | Dispatch | Installed | Dispatch |
| PGE-Bulk-2019-SP | Base Line | 2019 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 91 | 4,055 | 1,072 | 1,771 | 489 | 9,944 | 7,908 | 22,354 | 18,213 |
| PGE-Bulk-2019-ML | Base Line | 2019 spring light load conditions. Light load time - hours between 2:00 and 4:00 | 91 | 4,055 | 195 | 1,771 | 173 | 9,944 | 3,933 | 22,354 | 10,856 |
| PGE-Bulk-2022-SP | Base Line | 2022 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 91 | 4,193 | 1,132 | 1,771 | 571 | 9,944 | 7,900 | 22,354 | 17,682 |
| PGE-Bulk-2022-SpOP | Base Line | 2022 spring off-peak load conditions. Off-peak load time - weekend morning | 91 | 4,193 | 4,078 | 1,771 | 1,730 | 9,944 | 5,505 | 22,354 | 9,908 |
| PGE-Bulk-2027-SP | Base Line | 2027 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 91 | 4,231 | 1,158 | 1,771 | 571 | 9,944 | 7,935 | 19,836 | 15,329 |
| PGE-Bulk-2027-SPP | Base Line | 2027 Summer partial peak. hours between 20:00 and 21:00 | 91 | 4,231 | 175 | 1,771 | 0 | 9,944 | 6,723 | 19,836 | 15,777 |
| PGE-Bulk-2027-SpOP | Base Line | 2027 spring off-peak load conditions. Off-peak load time - weekend morning | 91 | 4,231 | 4,078 | 1,771 | 1,730 | 9,944 | 5,589 | 19,836 | 6,778 |
| PGE-Bulk-2022-SP-HiRenew | Sensitivity | 2022 Summer peak load conditions with high renewables dispatch sensitivity | 91 | 4,193 | 4,078 | 1,771 | 1,730 | 9,944 | 8,206 | 22,354 | 9,767 |
| PGE-Bulk-2027-SP-PS | Sensitivity | 2027 Summer peak load conditions with peak shift sensitivity | 91 | 4,231 | 424 | 1,771 | 571 | 9,944 | 8,219 | 19,836 | 15,310 |
| PGE-Bulk-2022-SpOP-maxPV | Sensitivity | 2022 spring off-peak load conditions with maximum photovoltaic output | 91 | 4,193 | 2,139 | 1,771 | 106 | 9,944 | 2,210 | 22,354 | 3,704 |

**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 forecast conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50-60 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 2.4-4 shows the assumed load levels for selected areas under summer peak and non-peak conditions. The table shows gross PG&E load in all the cases studied and the load modifiers: Additional Achievable Energy Efficiency, output of the Behind the Meter solar PV generation, and it also shows the load for irrigational pumps and hydro pump storage plants if they are operating in the pumping mode. In the base cases, pumping load is modeled as negative generation. Net load is the gross load with the Additional Achievable Energy Efficiency and the output of the Behind the Meter solar PV generation subtracted and the pumping load added.

Table 2.4-4: Load and Load Modifier Assumptions – PG&E Bulk System

| BASE CASE | Scenario Type | Description | Gross PG&E Load MW | AAEE MW | BTM PV output MW | Irrigational pumps and hydro pump-storage, MW | Net Load MW |
|---|---|---|---|---|---|---|---|
| PGE-Bulk-2019-SP | Base Line | 2019 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 29,027 | 688 | 1,069 | 584 | 27,854 |
| PGE-Bulk-2019-ML | Base Line | 2019 spring light load conditions. Light load time - hours between 2:00 and 4:00 | 14,360 | 363 | 1 | 584 | 14,580 |
| PGE-Bulk-2022-SP | Base Line | 2022 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 29,850 | 1,144 | 1,329 | 644 | 28,021 |
| PGE-Bulk-2022-SpOP | Base Line | 2022 spring off-peak load conditions. Off-peak load time - weekend morning | 20,014 | 681 | 3,710 | 1,574 | 17,197 |
| PGE-Bulk-2027-SP | Base Line | 2027 Summer peak load conditions. Peak load time between 16:00 and 18:00 | 31,257 | 2,018 | 2,050 | 690 | 27,879 |
| PGE-Bulk-2027-SPP | Base Line | 2027 Summer partial peak. hours between 20:00 and 21:00 | 30,946 | 1,975 | 302 | 690 | 29,359 |
| PGE-Bulk-2027-SpOP | Base Line | 2027 spring off-peak load conditions. Off-peak load time - weekend morning | 20,850 | 1,199 | 5,727 | 1,310 | 15,234 |
| PGE-Bulk-2022-SP-HiRenew | Sensitivity | 2022 Summer peak load conditions with high renewables dispatch sensitivity | 28,016 | 743 | 3,928 | 644 | 23,989 |
| PGE-Bulk-2027-SP-PS | Sensitivity | 2027 Summer peak load conditions with peak shift sensitivity | 31,257 | 2,018 | 552 | 690 | 29,377 |
| PGE-Bulk-2022-SpOP-maxPV | Sensitivity | 2022 spring off-peak load conditions with maximum photovoltaic output | 13,595 | 822 | 4,739 | 1,178 | 9,212 |

**Existing Protection Systems**

Extensive SPS or RAS are installed in the northern California area’s 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. Comprehensive details of these protection systems are provided in various ISO operating procedures, engineering and design documents.

## 2.4.3. 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 standards 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 Category P0 overloads: Los Banos-Quinto and Moss Landing – Las Aguilas 230 kV transmission lines were identified on the PG&E Bulk system in the Spring off-Peak base cases. The Warnerville-Wilson 230 kV transmission line may overload under normal system conditions in the 2027 Partial peak if the series reactor planned to be installed on this line is not inserted. In addition, the Eight Mile-Lodi 230 kV line was identified as overloaded under normal system conditions in the 2019 Summer Light Load case due to low load and high generation in the Lodi area. The Midway- Belridge Junction section of the Midway-Temblor 115 kV line was identified as overloaded in the 2027 Partial Peak case. No additional Category P0 overloads were identified in the sensitivity cases. The same transmission lines were also overloaded with single and double contingencies. Possible solutions are congestion management to reduce loading on the transmission lines. Another solution may be an upgrade of the overloaded lines if it appears to be economic.
- Three Category P1 overloads were identified under summer peak conditions. These overloads included two circuits in the same corridor: Round Mountain-Table Mountain # 1 and # 2 500 kV lines and one 115 kV line: Trimble-San Jose B. Under the off-peak conditions, two overloads were identified, that were the same two 230 kV transmission lines overloaded under P0 conditions. In the 2027 Summer Partial Peak case one transformer, Gates 500/230 kV, was identified as overloaded with a Category P1 contingency, as well as the Midway- Belridge Junction section of the Midway-Temblor 115 kV line that was also overloaded under normal conditions in this case. In the sensitivity cases, these facilities were either not overloaded, or their overload was lower. Possible solutions are to use congestion management, or to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines should they overload under peak load conditions. Another solution to mitigate the Round Mountain-Table Mountain overload is to operate the system within the seasonal COI nomogram. Overloads on the Round Mountain-Table Mountain # 1 and # 2 500 kV lines were identified with an outage of the parallel circuit in all summer peak cases due to high COI flow and high northern California hydro generation output. For other transmission lines overloads, the solutions are either congestion management or the transmission line upgrade if it appears to be economic. Overloads on the Gates 500/230 kV transformer will be mitigated when the second Gates 500/230 kV transformer will be installed, which is an approved project.

- A number of potential overloads for Category P6 and P7 contingencies (double outages) were identified.
    - The most critical Category P6 (overlapping outages of two transmission facilities) overload appeared to be on the Moss Landing-Las Aguilas 230 kV transmission line that was identified under off-peak conditions. This transmission line is expected to overload with an outage of any two 500 kV transmission lines or one 500 kV line and one 500/230 kV transformer between Tesla, Metcalf, Los Banos and Moss Landing, as well as with several outages of one of these 500 kV lines together with the underlying 230 kV lines. An outage of the Moss Landing-Los Banos 500 kV line along with the outage of Metcalf -Tesla 500 kV line appeared to be the most severe. There were several other transmission facilities in addition to the Moss Landing-Las Aguilas 230 kV line that might overload with the same contingencies. The overload is expected if the Moss Landing power plant is at the low output and the new renewable project connected to the Moss Landing-Panoche and Panoche-Coburn 230 kV lines is at the high output. In the studies, it was assumed that the Moss Landing #6 and #7 units are retired and the units # 1 and # 2 are re-powered at the 85% of their capacity. Potential mitigation measures may include: using short-term rating for the overloaded transmission line, increasing generation from Moss Landing and reducing it from the new project, and dispatching all available generation in San Jose. If these measures appear not to be sufficient, some load in the Moss Landing area may need to be tripped, or San Jose 115 kV transmission system sectionalized if the overloads in San Jose remain. Another solution is upgrading the line is it appears to be economic. Overload on the Moss Landing-Las Aguilas 230 kV transmission line with the Category P6 contingencies may be severe enough to cause cascading outages.
    - Another critical Category P6 overload is the Los Banos-Quinto 230 kV line, which also may overload under normal conditions and with Category P1 contingencies. It may overload under off-peak conditions and its overload also may be severe enough to cause cascading outages. Potential mitigations are congestion management or line upgrade, depending on economic benefits. However, due to the high amount of overload, congestion management or the upgrade have to be significant. Los Banos-Quinto is a part of the Los Banos-Westley 230 kV transmission line. The Quinto-Westley section of this line was reconductoted when the generation project connected to the Los Banos-Westley line came on-line, but it may also overload for several double contingencies. Its overload could potentially be addressed by congestion management
    - Other facilities that are expected to overload with Category P6 contingencies of the 500 kV lines between Tesla, Metcalf, Moss Landing and Los Banos include Las Aguilas-Panoche #1 and #2 230 kV transmission lines, Moss Landing-Coburn 230 kV line, Los Esteros-Newark 230 kV line, Trimble-San Jose B 115 kV line and Newark-Lockheed Junction section of the Newark-Lawrence 115 kV line. The same mitigation measures proposed for the overload of the Moss Landing-Las Aguilas 230 kV transmission line will also mitigate overload on these facilities. The Trimble-San Jose B 115 kV line may overload with 500 kV Category P6 contingencies between Metcalf,

Tesla, Los Banos and Moss Landing also under peak load conditions if the generation in San Jose is low.

- o Transmission facilities overloaded with other Category P6 contingencies appeared to be less severe and are expected in fewer cases. They include overload on the Metcalf 500/230 kV or Midway 500/230 kV transformer banks with an outage of two parallel transformers under off-peak conditions. These overloads can be mitigated by dispatching generation in San Jose after the first contingency and, as a last resort, tripping some of the load in San Jose for Metcalf transformer overload, and reducing some generation at Midway for the Midway transformer overload. Other overloaded facilities in Northern California identified in the P6 contingencies studies were Round Mountain 500/230 kV and Olinda 500/230 kV transformers under off-peak conditions, Tracy 500/230 kV transformers #1 and #2 under summer partial peak conditions in 2027 and Cottonwood-Round Mountain #2 and #3 230 kV lines under summer peak conditions. Potential mitigation for the Olinda 500/230 kV transformer overload is applying existing Colusa SPS, to trip Colusa generation if Colusa power plant is generating, or congestion management by reducing Shasta generation. A mitigation for the Round Mountain 500/230 kV transformer overload is congestion management by reducing Pit River generation. To mitigate Tracy 500/230 kV transformer overload, the potential solution may be opening of the Tracy-Tesla 230 kV lines and/or tripping some of the Tracy pumping load. Potential mitigation solutions to the Cottonwood-Round Mountain 230 kV lines overloading, which may also occur with Category P6 contingencies, may be limiting COI within the seasonal nomograms or reducing Pit River generation after first contingency.
- o A Category P6 overload was identified in the 2019 Summer Peak case in the Palermo-Rio Oso area (Rio Oso-Greenleaf tap 115 kV). This overload will be mitigated by the South of Palermo Transmission Project. Prior to this project being implemented, some generation reduction after the first contingency may be required.
- o Ten Category P6 230 kV transmission line overloads were identified in central and southern PG&E area under off-peak conditions. Morro Bay-Switching Station #1 and #2 sections of the Morro Bay- Midway 230 kV circuits may overload with Category P6 contingencies of the parallel 230 kV line and one of the 500 kV facilities in the area under off-peak load conditions. The mitigation will require reducing generation from the Topaz renewable project. The Gates-Midway 230 kV line may overload above its short-term emergency rating for one Category P6 contingency. The Tesla-Los Banos, Tracy-Los Banos or Los Banos-Midway 500 kV transmission lines may overload under off-peak conditions with the N-1-1 contingency of two 500 kV transmission lines from the Los Banos Substation and may require reducing Path 15 flow as required by the Operational Procedure for Path 15. To mitigate overload on the Panoche Gates #1 and #2 230 kV lines and on the Panoche-Dos Amigos 230 kV line, the Operational Procedure for Path 15 needs to be followed as well. Overload of the Gates 500/230 kV transformer will be mitigated when the second 500/230 kV transformer bank is installed on the Gates substation.

- The Delevan-Cortina 230 kV line was identified as overloaded for several Category P6, as well as one Category P7 contingencies under peak and partial peak load conditions. Possible solutions are to use congestion management or to rerate or upgrade this line. Delevan-Cortina 230 kV line overload substantially depends on the output of Colusa generation. Its overload was not identified in the cases where Colusa power plant was not fully dispatched.
- The Warnerville-Wilson and Bellota-Warnerville 230 kV transmission lines may overload with Category P6 contingencies if the series reactor planned to be installed on the Warnerville-Wilson line and currently in construction is not inserted. The Warnerville-Wilson 230 kV line may overload under partial peak conditions, and the Bellota-Warnerville 230 kV may overload under off-peak conditions. Insertion of the series reactor will mitigate the overloads. In addition, installation of the second Gates 500/230 kV transformer which is an approved project will allow to avoid overloads with contingencies involving existing Gates 500/230 kV bank.
- Other transmission facilities that may overload for Category P6 contingencies include the Lone Tree-Cayetano 230 kV line, Eight Mile-Lodi 230 kV line and Midway-Belridge Junction section of the Midway-Temblor 115 kV line. The Eight Mile–Lodi 230 kV line may also overload under normal conditions and will be reconductored in December 2019. Prior to reconductoring, congestion management to reduce generation in Lodi can be used. The Lone Tree-Cayetano overload can be mitigated by congestion management. The Midway-Belridge Junction overload can be mitigated either by congestion management or line upgrade.

- There were a number of transmission facilities identified as overloaded with Category P7 (two adjacent circuits) contingencies.
  - Potential overloads for Category P7 contingencies under summer peak and partial peak load conditions included overload on the Captain Jack-Olinda 500 kV line, Cottonwood-Round Mountain 230 kV lines #2 and #3, Delevan-Cortina 230 kV line, Table Mountain-Rio Oso 230 kV line and Drum-Rio Oso 115 kV line. Potential mitigation measures are as follows: operate COI within the seasonal nomogram, upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line, possible upgrade of Cottonwood-Round Mountain 230 kV lines, congestion management for the Drum-Rio Oso 115 kV overload and rerate of the Delevan-Cortina 230 kV line.
  - In addition to the facilities listed above, there were more overloads for Category P7 contingencies under 2027 partial peak load conditions. These overloads included the Gates 500/230 kV transformer and the Warnerville-Wilson 230 kV line. The second Gates 500/230 kV transformer project and insertion of the series reactor on the Warnerville-Wilson 230 kV line will mitigate the overloads.
  - Under off-peak conditions, Category P7 contingency overloads included overloads on the Olinda and Round Mountain 500/230 kV transformers, Warnerville-Wilson, Los Banos-Quinto, Westley-Quinto, and Moss Landing–Las Aguilas 230 kV lines. These overloads may be mitigated by congestion management or tripping some generation

in the area. Overloads on the Los Banos-Quinto and Moss Landing–Las Aguilas 230 kV lines may require upgrading the facilities if the upgrades appears to be economic.

- o No overloads were identified under minimum load conditions for the Category P7 contingencies

The following table summarizes the overloaded facilities and the options for their mitigation.

Table 2.4-5. Overloaded facilities and contingencies causing thermal overload

| Overloaded Facility | Contingencies that may cause overload | | | | | | | | | | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 Summer Peak | 2022 Summer Peak | 2027 Summer Peak | 2027 Summer Partial Peak | 2019 Light Spring | 2022 Spring Off-peak | 2027 Spring Off-peak | 2022 Summer Peak, High renew | 2027 Summer Peak shift | 2022 Spring Off-peak, max PV | |
| 500 kV LINES | | | | | | | | | | | |
| ROUND MTN –TABLE MTN #1 or #2 500kV | P1, P2, P6 | P1, P2, P6 | P1, P2, P6 | P1, P2, P6 | | | | P1, P2, P6 | P1, P2, P6 | | Operate within seasonal COI nomogram |
| CAPTAIN JACK-OLINDA 500 kV | P6, P7 | P6, P7 | P6, P7 | P6, P7 | | | | P6, P7 | P6, P7 | | Operate within seasonal COI nomogram |
| OLINDA-MAXWELL 500 kV | P6 | | P6 | | | | | P6, P7 | | | Operate within seasonal COI nomogram |
| MAXWELL-TRACY 500 KV | | | | | | | | P7 | | | Operate within seasonal COI nomogram |
| TESLA-LOS BANOS 500 kV | | | | | | P6 | | | | | Follow Path 15 Operational Procedure |
| TRACY-LOS BANOS 500 kV | | | | | | P6 | | | | | Follow Path 15 Operational Procedure |
| LOS BANOS-MIDWAY 500 kV | | | | | | P6 | | | | | Follow Path 15 Operational Procedure |
| 500/230 kV TRANSFORMERS | | | | | | | | | | | |
| ROUND MTN 500/230 kV x-former | | | | | | P6, P7 | P6, P7 | | | | congestion management, reduce Pit River generation |
| OLINDA 500/230 kV x-former | | | | | | P6, P7 | P6, P7 | | | | congestion management, reduce Shasta generation |
| TRACY 500 /230 kV x-former #1 or # 2 | | | | P6 | | | | | P6 | | open Tracy-Tesla 230 kV lines if overload, trip Tracy pumps if it persists |
| METCALF 500/230 kV x-former #11, 12 or 13 | | P6 | | P6 | | P6 | P6 | P6 | P6 | | dispatch San Jose generation after 1st contingency, trip load in San Jose if overload persists |
| GATES 500/230 kV x-former | | | | P1, P2, P6, P7 | | | | | | | install 2nd 500/230 kV Gates transformer, approved project |
| MIDWAY 500/230 kV x-former #11, 12 or 13 | | | | | | P6 | P6 | | | | congestion management, reduce generation at Midway 230 kV after first contingency |
| 230 kV LINES | | | | | | | | | | | |
| COTTONWD E-ROUND MTN 230kV #2 | | P7 | P7 | P7 | | | | P7 | P7 | | limit COI import within nomogram or upgrade the line if economic |
| COTTONWD E-ROUND MTN 230kV #3 | | P6, P7 | P6, P7 | P6, P7 | | | | P6, P7 | P6, P7 | | limit COI import within nomogram or upgrade the line if economic |
| TABLE MTN-RIO OSO 230 kV | P6, P7 | | | | | | | | | | upgrade terminal equipment, PG&E project |
| LONE TREE-CAYETANO 230 kV | | | | P6 | | | | | | | congestion management, reduce generation at Contra Costa |
| LS ESTEROS - NEWARK 230 kV | | | | | | P6 | | P6 | | | dispatch Metcalf generation after 1st contingency |
| DELEVAN-CORTINA 230 kV | P6, P7 | P6 | P6 | P6, P7 | | | | | | | reduce Colusa generation or re-rate the line |
| BELLOTA-WARNERVILLE 230 kV | | | | | | P6, P7 | | | | | insert series reactor on the Warnervile-Wilson 230 kV line |
| WARNERVILLE-WILSON 230 kV | | | | P0, P1, P6, P7 | | P7 | P7 | | | | insert series reactor on the Warnervile-Wilson 230 kV line |
| EIGHT MILE-LODI 230 kV | | | | | P0, P6 | | | | | | reconductoring in December 2019, reduce Lodi generation under normal conditions prior to that |
| LOS BANOS - QUINTO_SS 230 kV | | | | | | P0, P1, P2, P6, P7 | P0, P1, P2, P6, P7 | | | P7 | reduce Path 15 flow according to Ops Procedure or upgrade if economic |
| WESTLEY - QUINTO_SS 230 kV | | | | | | P6, P7 | P6, P7 | | | | reduce Path 15 flow according to Ops Procedure or reduce generation from renewable project |
| MOSSLANDING-LAS AGUILAS 230 kV | | | | | | P0, P1, P2, P6, P7 | P0, P1, P2, P6, P7 | P6 | | | congestion management, or upgrade if economic |
| MOSS LANDING-COBURN 230 kV | | | | | | P6 | P6 | | | | dispatch Moss Landing after 1st contingency |
| LAS AGUILASS-PANOCHE 230kV #1 or #2 | | | | | | P6 | | | | | dispatch Moss Landing after 1st contingency |
| PANOCHE-DOS AMIGOS 230 kV | | | | | | P6 | P6 | | | | follow Operational Procedure for Path 15 |
| PANOCHE-GATES # 1 and 2 230 kV | | | | | | P6 | P6 | | | | follow Operational Procedure for Path 15 |
| MORROBAY- SOLARSS 230 kV # 1 or # 2 | | | | | | P6 | P6 | | | | congestion management, reduce generation from Topaz Solar after first contingency |
| GATES-MIDWAY 230 kV | | | | | | P6 | | | | | follow Operational Procedure for Path 15 |
| 115 kV LINES | | | | | | | | | | | |
| DRUM-BRUNSW-RIO OSO 115 kV | P7 | P7 | | P7 | | | | P7 | P7 | | congestion management, reduce Drum generation |
| RIO OSO-GREENLEAF TAP 115 kV | P6 | | | | | | | | | | South of Palermo project, limit COI within nomogram prior to it |
| NEWARK F - LOCKHID Jct1 115kV | | | | P6 | | | | | P6 | | dispatch Metcalf generation after 1st contingency |
| TRIMBLE - SAN JOSE B DG 115 kV | P6 | P1, P2,P6 | P1, P2,P6 | P6 | | P6 | | P6 | P1, P2,P6 | | reduce generation from Los Esteros or increase generation from Metcalf, or upgrade the line |
| MIDWAY-BELRIDGE JCT (MIDWAY-TEMBLOR) 115 kV | | | | P0, P1, P6 | | | | | | | install 2-nd Gates 500/230 kV transformer and decrease generation at Midway or dispatch generation at Pump Jack after first contingency if overload expected |

The ISO-proposed solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Keep the existing Moss Landing Power Plant and Metcalf Energy Center operational to mitigate overload with several Category P6 contingencies.
- For overloads that are managed with congestion management or operating with in the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the ugrades are determined to be economically-drive. The following lines were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms.
    - Cottonwood-Round Mountain 230 kV # 2 transmission line
    - Cottonwood-Round Mountain 230 kV # 3 transmission line
    - Delevan-Cortina 230 kV transmission line (possible rerate)
    - Los Banos- Quinto 230 kV transmission line
    - Moss Landing-Las Aguilas 230kV transmission line
    - Trimble-San Jose B 115 kV transmission line
    - Midway-Belridge Jct section of the Midway-Temblor 115 kV transmission line
- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

The studies identified high voltages in the 500 kV system in Central California starting when Diablo Canyon Nuclear Power Plant retires, which is currently planned for 2025 and reflected in the 2027 cases. It is recommended to consider installing additional reactive devices, preferably dynamic, so that they could both absorb reactive power under normal system conditions and supply reactive power with contingencies as needed. A more detailed study will specify exact locations, sizes and types of this reactive support.

High voltages were identified on the sub-transmission system under off-peak conditions as well. These were due to large amount of renewable generation connecting to this system. If the new renewable generation projects have the ability to absorb reactive power, the voltages in the sub-transmission system will be more manageable.

The sensitivity studies identified insufficient reactive margin with several contingencies in the 2022 Summer Peak case with high renewable and low gas generation for several, mainly extreme, contingencies. The reason for insufficient reactive margin was that several conventional generation units in Northern California were off-line in this sensitivity case and high output from renewable resources was mainly in Central California. In addition, the renewable projects did not provide as much of the reactive support as the conventional units. Potential mitigation solution is to install additional dynamic reactive support in Central and Northern California 500 kV system in case of high penetration of renewable resources that would cause many conventional generation units to mainly be off-line. Another solution is to keep conventional units on-line so that they would provide necessary reactive support.

Dynamic stability studies had the load in WECC, including the ISO, modeled with the WECC composite load models. In addition to loads, behind the meter distributed generation (solar PV) was explicitly modeled as well. The load was modeled according to the current WECC composite load model Phase I with the stalling of single-phase air-conditioners disabled, as well as with composite load model Phase II with the stalling of single-phase air-conditioners enabled. Parameters of the composite load model were selected according to the WECC recommendations and research. Dynamic stability studies used the new WECC Transmission Planning criteria that included transient voltage recovery.

The dynamic studies showed significant difference in the results depending on either the stalling of single phase air conditioning load was enabled or disabled.

The following conclusions can be made from the dynamic stability studies:

- Due to high voltages in the power flow cases, some renewable units may be tripped.
- Several renewable generation projects were tripped by low or high voltage, or low or high frequency with three-phase faults close to the units, which is most likely a modeling issue.
- Composite load model tripped some fraction of load with 3-phase faults because of low voltages. The reduction of load due to partial load tripping by composite load model is a non-consequential load loss, and therefore it is within the NERC reliability criteria.
- No criteria violations were identified with single phase A/C stalling disabled.
- Slow voltage recovery was identified on several low voltage buses with single phase A/C stalling enabled. However, no criteria violations were identified on high voltage buses, therefore, the system performance was within the criteria.
- More work is required on the load and distributed generation modeling. Several possible modeling errors were reported to the Participating Transmission Owners and to the generation owners, so that the equipment would be re-tested to update the model parameters. Also, the ISO is working with the PTOs and generation owners on the improving the models and on the model parameters to achieve more accurate study results.
- Several renewable units were modeled with unity power factor. The requirement to the new renewable generation projects of the 0.95 lead/lag power factor will provide voltage regulation and may mitigate high or low voltages, as well as allow to avoid tripping of the units due to abnormal voltages.

### Request Window Proposals

Round Mountain Dynamic Reactive 500 kV Transmission System

The following project was submitted in the 2017 Request Window as a transmission solution to resolve the insufficient reactive margin with several contingencies and high renewable generation output, as well as the issue of high voltage in the 500 kV in Northern California under off-peak conditions. The project was proposed by a non-PTO entity.

The proposed project consists of:

- A new ± 300 MVAR SVC connected to a new 500 kV bus through a single 500/230 kV step-up transformer, with a rating of approximately 340 MVA.
- A new 500 kV tie-line connecting the high-side bus of the SVC step up transformer to PG&E's existing Round Mountain 500 kV substation. The line ratings of this line will be approximately 330 MVA Normal/Emergency.
- A new bay position at the Round Mountain 500 kV bus consisting of two new 500 kV breakers.

Similar reactive support device may be also installed at the Gates 500 kV substation to mitigate high voltages in the 500 kV system in Central California after the Diablo Nuclear Power Plant retires.

The ISO reviewed this proposal and concluded that the proposal is valid, but additional studies are required to determine the exact locations and the size of the devices. The ISO will be continuing to assess the bulk system reactive needs after the retirement of the Diablo generation in the 2018-2019 transmission planning process.

## 2.5 PG&E 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 PG&E Humboldt area.

Humboldt's electric transmission system is comprised 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. 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. 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.

#### 2.5.1.2 *Area-Specific Assumptions and System Conditions*

The Humboldt 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Humboldt Area study are provided below.

Table 2.5-1: Humboldt load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| HUMB-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 140 | 10 | 14 | 5 | 126 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 125 |
| HUMB-2019-WP | Baseline | 2019 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 151 | 10 | 14 | 0 | 141 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 83 |
| HUMB-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 80 | 7 | 14 | 0 | 73 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 164 |
| HUMB-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 116 | 13 | 14 | 3 | 101 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 207 |
| HUMB-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 145 | 17 | 19 | 6 | 122 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 126 |
| HUMB-2022-WP | Baseline | 2022 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 157 | 17 | 19 | 0 | 140 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 166 |
| HUMB-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 119 | 13 | 19 | 18 | 89 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 154 |
| HUMB-2022-SP-PS-AAEE | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 122 | 0 | 19 | 2 | 119 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 207 |
| HUMB-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 155 | 30 | 30 | 10 | 115 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 110 |
| HUMB-2027-WP | Baseline | 2027 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 171 | 31 | 30 | 0 | 140 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 110 |
| HUMB-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 135 | 40 | 30 | 3 | 92 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 207 |
| HUMB-2022-SP-HiRenew | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 134 | 14 | 19 | 19 | 101 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 207 |
| HUMB-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 171 | 31 | 30 | 0 | 140 | 4 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 264 | 110 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of the approved projects indentified in Table 2.5-2 that were not modeled in the study scenario base cases.

Table 2.5-2: Humboldt approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Bridgeville – Garberville No. 2 115 kV Line | 2011-2012 TPP | Jan-2024 |

### 2.5.1.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Humboldt Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

<u>Eel River-Newburg 60kV line</u>

Category P2 contingency overloads are identified in the Eel River-Newburg 60kV line resulting in non-convergence. A potential mitigation for the P2 contingency reliability issues is to reconductor the Eel River- Newburg 60 kV line (From Tower 11/4 to 15/5). The ISO will continue to assess in the 2018-2019 TPP.

*Summary of review of previously-approved projects*

There is 1 previously-approved active project in the Humboldt not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. Table 2.5-3 below shows final recommendation for this one project not modeled in the study cases:

Table 2.5-3: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Bridgeville – Garberville No. 2 115 kV Line | Hold |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussion of projects recommended to proceed with revised scope:

<u>*Bridgeville – Garberville No. 2 115 kV Line*</u>

Categories P1, P2, P3 and P6 thermal overloads summer and winter as well as in multiple sensitivity scenarios including two peak-shift sensitivities. The ISO is recommending for the "*New Bridgeville – Garberville No. 2 115 kV Line*" to be on hold to further assess alternatives in the next cycle to mitigate the constraints.

<u>Original Scope:</u>

- Build a new 36 mile Bridgeville – Garberville No.2 115 kV line as a DCTL (built to 115 kV specs) with the existing Bridgeville – Garberville No.1 60 kV Line.
- Build a new 115 kV bus and install a 115/60 kV transformer at Garberville substation.
- 2011-2012 TPP estimated cost: $55 to $65 million
- Current estimated cost: $80 to $90 million
- Current In-service date: Jan-2024

<u>Alternative:</u>

- To address P1 contingency, re-dispatch generation at Humboldt Bay Power Plant.
- Reconductor the Humboldt – Rio Dell Jct line from tower 1/2 to tower 3/7, tower 3/12 to tower 6/1, tower 6/6 to 11/4, tower 15/4 to 19/6 (i.e. the 336.4-19 AAC and 4/0-7 AAC sections), which is approximately 13 miles with a WE rating of at least 600 amps.
- Reconductor the Humboldt – Rio Dell Jct Line from Tower 11/4 to 15/5 with a WE rating of at least 600 amps (same conductor as the second item of this project scope).
- Rerate sections of the Rio dell – Bridgeville line to 4 feet per second from Rio Dell Junction (tower 19/6) to Carlotta Substation and Swains Flat substation to Bridgeville Substation. Rerate the Bridgeville – Garberville Line to 4 feet per second.
- 2017-2018 TPP estimated cost: $60 million
- In-service Date: 2023

### 2.5.1.4 *Request Window Submissions*

There are no Request Window Submissions for the Humboldt Area.

### 2.5.1.5 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1.2, about 17 MW of AAEE and more than 6 MW of installed behind-the-meter PV reduced the Humboldt Area load in 2022. This year's reliability assessment for Humboldt Area included "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 4 MW less behind-the-meter PV output. Comparison between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that following facility overloads are potentially avoided due to reduction in net load.

Table 2.5-4: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Humboldt – Trinity 115 kv Line | P6 |
| Eureka - Humboldt 60 kV Line | P2 |
| Humboldt – Eel River 60 kV Line | P2 |
| Eel River – Newburg 60 kV Line | P2 |
| Newburg – Riodale Tap 60 kV Line | P2 |
| | |

Furthermore, about 4 MW of demand response are modeled in Humboldt. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn't completely alleviate the overloads.

### 2.5.1.6 *Recommendation*

Based on the studies performed for the 2016-2017 Transmission Plan, several reliability concerns were identified for the PG&E Humboldt. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by the previously-approved projects within the Humboldt.

The Bridgville-Garberville No. 2 115 kV line project is recommened to be on hold to further assess alternatives in the next cycle. For the areas identified that require additional mitigation, the ISO will continue to assess in the 2018-2019 TPP to potentially reconductor the Eel River- Newburg 60 kV line (From Tower 11/4 to 15/5).

## 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. 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 Napa and portions of Marin, Solano and Sonoma counties.

The larger cities served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is composed of 60 kV, 115 kV and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento and the Bay Area. 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-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Coast and North Bay Area study are provided below.

Table 2.5-5: North Coast and North Bay load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Geo-Thermal | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| NCNB-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,447 | 34 | 247 | 91 | 1,322 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 19 | 254 | 123 |
| NCNB-2019-WP | Baseline | 2019 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,533 | 35 | 247 | 0 | 1,497 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 22 | 254 | 123 |
| NCNB-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 692 | 23 | 247 | 0 | 669 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 36 | 254 | 123 |
| NCNB-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 1,418 | 45 | 247 | 57 | 1,316 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,479 | 54 | 336 | 113 | 1,311 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2022-WP | Baseline | 2022 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,566 | 57 | 336 | 0 | 1,510 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 1,074 | 43 | 336 | 318 | 714 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 36 | 254 | 123 |
| NCNB-2022-SP-PS-AAEE | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 1,421 | 0 | 336 | 44 | 1,377 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,561 | 90 | 513 | 176 | 1,295 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2027-WP | Baseline | 2027 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,654 | 98 | 513 | 0 | 1,557 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 21 | 254 | 123 |
| NCNB-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 1,474 | 125 | 513 | 48 | 1,302 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 38 | 254 | 123 |
| NCNB-2022-SP-HiRenew | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 1,390 | 47 | 336 | 336 | 1,007 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 36 | 254 | 123 |
| NCNB-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 1,561 | 90 | 513 | 176 | 1,295 | 13 | 8 | 10 | 0 | 0 | 1367 | 689 | 153 | 33 | 254 | 123 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of previously-approved projects in Table 2.5-6 that were not modeled in the base cases:

Table 2.5-6: North Coast / North Bay approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Fulton-Fitch Mountain 60 kV Line Reconductor (Fulton-Hopland 60 kV Line) | 2009 TPP | Jun-2019 |
| Fulton 230/115 kV Transformer | 2010-2011 TPP | May-2022 |
| Clear Lake 60 kV System Reinforcement | 2009 TPP | Feb-2023 |
| Ignacio – Alto 60 kV Line Voltage Conversion | 2011-2012 TPP | Mar-2023 |
| Napa – Tulucay No. 1 60 kV Line Upgrades | 2011-2012 TPP | Jul-2020 |

### 2.5.2.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E North Coast North Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

*Lakeville 60 kV Area Reinforcement*

For category P6 contingency of both the Fulton #1 & #2 115/60 kV transformer banks in the 2019, 2022 and 2027 summer peak and winter peak conditions resulted in the case diverging.

The ISO considered the installation of and SPS to drop load to mitigate the reliability constraint with an estimated at $3-5 million; however with the with the cost difference and only a small section of line to reconductor and terminal equipment upgrades the ISO is recommending approval of this “Lakeville 60 kV Area Reinforcement" project which includes the following:

- Reconductor the line sections on the Lakeville #2 60 kV Line between Petaluma A to Lakeville Junction (tower 4/100) and Cotati to tower 11/236 (approx. 3.39 miles) with 397.5 AAC
- Upgrade the capacity of the Petaluma A bus conductor with at least a summer emergency (SE) rating of 490 amps (currently, the bus consists of 250 Cu)
- Upgrade limiting equipment, including terminal equipment and disconnect switches, on the line and buses so that the full capacity of the line can be used.

- Open 60kV line between Cotati and Petaluma
- Current estimated cost: $ 7M
- Current In-service date: 2021

*Lakeville-Vaca Dixon and Tulucay-Vaca Dixon 230 kV Line*

The overloads identified in previous planning cycles in the summer conditions are decreasing due to the lower forecast for this area with the summer peak shift base case for 2022 and 2027. P2 and P6 contingencies result in increasing overloads in the Winter Peak study scenarios in 2019, 2022 and 2027 on the Lakeville-Vaca Dixon 230 kV line and in the Winter Peak study scenarios in 2022 and 2027 on Tulucay-Vaca Dixon 230 kV. In addition the loading in the Peak Shift sensitivity scenarios on these two lines is at the emergency ratings for the same contingencies.

The ISO is recommending approval of the “Vaca-Lakeville 230 kV Corridor Series Compensation" project which includes installing series compensation device on these 230 kV lines. Estimated cost of this project is around $11M. The expected in-service date for this project October 2019. The ISO also received project proposal from Smart Wires in 2017 Request Window to address these overloads which is discussed in the “Request Window Submissions” section.

### Summary of review of previously-approved projects

There are 5 previously-approved active projects in the North Coast North Bay Area, out of which all 5 projects are not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. Table below shows final recommendation for the 5 projects not modeled in the study cases:

Table 2.5-7: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Fulton-Fitch Mountain 60 kV Line Reconductor (Fulton-Hopland 60 kV Line) | Revised scope |
| Fulton 230/115 kV Transformer | Cancel |
| Clear Lake 60 kV System Reinforcement | Revised scope |
| Ignacio – Alto 60 kV Line Voltage Conversion | Revised scope |
| Napa – Tulucay No. 1 60 kV Line Upgrades | Cancel |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussion of projects recommended to proceed with revised scope:

*Fulton-Fitch Mountain 60 kV Line Reconductor (Fulton-Hopland 60 kV Line)*

Category P1, P2 and P7 contingency overloads were identified on the Fulton-Fitch Mountain 60 kV Line in summer peak cases and multiple sensitivity scenarios. P2 contingency were also observed in multiple sensitivity cases including 2027 peak shift sensitivity. To mitigate these overloads, the ISO is recommending approval of the "Fulton-Fitch Mountain 60 kV Line Reconductor" (revised scope) and to rename the project to "Fulton-Hopland 60 kV Line".

Original Scope:

- Reconductor the Fulton – Hopland 60 kV line (Fulton- Fitch Mountain Tap 8 mile section) with conductor rated for 742 Amps or higher summer emergency rating.
- 2009 TPP estimated cost: $5 million
- Current estimated cost: $29 million
- Current In-Service Date: June-2019

Revised Scope:

- Reconductor the Fulton – Hopland 60 kV line (Fulton- Fitch Mountain Tap 8 mile section) with conductor rated for 383 Amps or higher summer emergency rating (477 ACSR)
- Rerate another section of the Fulton – Hopland 60 kV Line (Tower 9/5A- Tower 16/3A 7.1 mile section) with conductor rated for 423 Amps or higher summer emergency rating (477 ACSR).
- And rerate the Fitch Mountain #2 60 kV Tap (Tower 9/19A – Fitch Mountain 0.07 mile section) with conductor rated for 373 Amps or higher summer emergency rating (477 ACSR).
- 2017-2018 TPP estimated cost: $31 million
- In-service Date: June 2019

*Fulton 230/115 kV Transformer*

The P6 contingency of either of the Fulton #4 & #9 230/115 kV transformers followed by the loss of the remaining Fulton 230/115 kV transformer results in the load of the 115kV system being supplied from the Lakeville 115kV through the Santa Rosa – Corona 115kV and the Corona to Lakeville 115kV lines. The project was not modeled in the study cases to assess potential alternative mitigation plans to address the needs in the current reliability assessment. The Fulton 230/115 kV Transformer project approved in the 2010-2011 TPP mitigates the overloads observed; however the overloads observed in the 2017-2018 TPP reliability assessment have reduced from previous cycles due to the lower load forecast in the area.

The previously-approved project is recommended to be canceled and recommend PG&E to install an SPS to mitigate the overloads on the Santa Rosa – Corona 115kV and the Corona to Lakeville 115kV lines for the P6 contingency.

*Clear Lake 60 kV System Reinforcement*

Category P1, P2, P3 and P6 contingency overload were also identified in the Clear Lake 60kV area in winter peak cases and multiple sensitivity scenarios including the two 2019 and 2027 peak-shift scenarios. This project was not modeled in the study cases due to high cost increase in recent estimate. An alternative of Reconductor Clear Lake – Hopland 60 kV line and installing a 10-15 MVAR shunt capacitor at Middletown 60 kV substation or adding an energy storage facility at either Clear Lake 60kV Substation or Lower Lake 60kV Substation mitigates identified overloads at much less cost without causing any new reliability concerns. The ISO is recommending approval of the “Clear Lake 60 kV System Reinforcement” (revised scope).

Original Scope:

- Build approximately 12 miles long new 115 kV line with 345 Amps or higher summer emergency rating to Middletown Substation.
- Install a new 100 MVA or higher, 115/60 kV transformer at Middletown Substation.
- 2009 TPP estimated cost: $20 to 30 million
- Current estimated cost: $50 million
- Current In-Service Date: February 2023

Revised Scope:

- Reconductor Clear Lake – Hopland 60 kV line (approx 11.5 miles) with a higher conductor rating of at least 413 Amps SE and upgrade limiting equipment on the line so full capacity of line can be used.
- Install a 10-15 MVAR shunt capacitor at Middletown 60 kV substation along with the associated interconnecting equipment (i.e. circuit breaker).
- 2017-2018 TPP estimated cost: $15 million
- In-service Date: 2022

*Ignacio – Alto 60 kV Line Voltage Conversion (Ignacio Area Reinforcement)*

Category P1, P2, P3, P6 and P7 contingency overloads summer Peak load conditions were identified in summer peak cases and multiple sensitivity cases including two peak shift sensitivity scenarios. ISO has evaluated the alternative to reconductor Ignacio- San Rafael #1 115 kV Line and the San Rafael Jct – Greenbrae line section of Ignacio – Alto 60 kV Line as well as upgrade limiting equipment on lines, to add a 10-20 MVAR shunt capacitor at Greenbrae 60 kV Substation and reconductor Ignacio- San Rafael #3 115 kV Line and upgrade limiting equipment. This alternative mitigates identified reliability issues at a lower cost compared to the cost of the previously-approved Ignacio – Alto 60 kV Line Voltage Conversion project. The ISO is recommending approval of the “Ignacio – Alto 60 kV Line Voltage Conversion” (revised scope) and to rename the project to “Ignacio Area Reinforcement“.

Original Scope:

- Replace limiting equipment on the Ignacio- San Rafael No. 1 115 kV Line at the San Rafael Substation end in order to achieve the full conductor rating of the line.
- Convert the Ignacio – Alto 60 kV Line from Ignacio Substation to Greenbrae Substation (15 miles) to 115 kV operation and loop the new 115 kV line into San Rafael Substation.
- Install 20-30 MVAR shunt capacitor for voltage support at Greenbrae 60 kV Substation.
- Upgrade associated terminal equipment to achieve maximum conductor rating.
- 2011-2012 TPP estimated cost: $35 to $45 million
- Current estimated cost: $50 million
- Current In-service date: March-2023

Revised Scope:

- Reconductor Ignacio- San Rafael #1 115 kV Line and reconductor San Rafael Jct – Greenbrae line section of Ignacio – Alto 60 kV Line as well as upgrade limiting equipment on lines.
- Add a 10-20 MVAR shunt capacitor at Greenbrae 60 kV Substation. Reconductor Ignacio-San Rafael #3 115 kV Line and upgrade limiting equipment.
- 2017-2018 TPP estimated cost: $37 million
- In-service Date: 2023

*Napa – Tulucay No. 1 60 kV Line Upgrades*

No contingency overloads are identified to sport the '*Napa – Tulucay No. 1 60 kV Line Upgrades*" therefore ISO recommends to cancel this project.

#### 2.5.2.4 *Request Window Submissions*

*Request Window Submission - Alto 45 MW & Las Gallinas 22 MW Battery Energy Storage Systems (BESS)*

NextEra Energy Resources, LLC (NextEra) is proposing the Alto 45 MW Battery Storage Project connecting to Alto 60 kV Bus, & Las Gallinas 22 MW Battery Storage Project connecting to Las Gallinas 115 kV Bus, which consists of the following two components:

1) The Battery Energy Storage System (BESS) Project will deliver a maximum of 45 MW at Alto 60kV bus and deliver a maximum of 22 MW at Las Gallinas 115kV. The BESS projects will be rated to account for 0.1 MW of auxiliary load.

   The Alto 45MW BESS project will be nominally rated at 45.98 MW, 4 hours (183.92 MWh) configured in racks connected in strings to bi-directional inverters and transformers.

   - (22) Parker 2.2MVA inverters with 95% Power Factor. Each inverter rated output of 2.09MW.

- ACSR 1272 KCMIL conductor will be used to connect the facility to the Alto 60kV substation bus.
- One 60kV – 34.5kV step up transformers will be used, rated at 50 MVA. Along with 22 pad-mount 34.5kV – 480V transformers will be used.

2) The Las Gallinas 22MW BESS project will be nominally rated at 22.99 MW, 4 hours (91.96 MWh) configured in racks connected in strings to bi-directional inverters and transformers.
    - (11) Parker 2.2 MVA inverters with 95% Power Factor. Each inverter rated output of 2.09MW.
    - ACSR 1272 kcmil conductor will be used to connect the facility to the Las Gallinas 115 kV substation bus.
    - One 115 kV – 34.5 kV step up transformers will be used, rated at 25 MVA. Along with 11 pad-mount 34.5 kV – 480 V transformers will be used.

The estimated cost of the proposed Alto 45 MW & Las Gallinas 22 MW BESS Projects is approximately $100 Million in 2022 dollars with an estimated in-service date of 2022.

Alternatives Considered

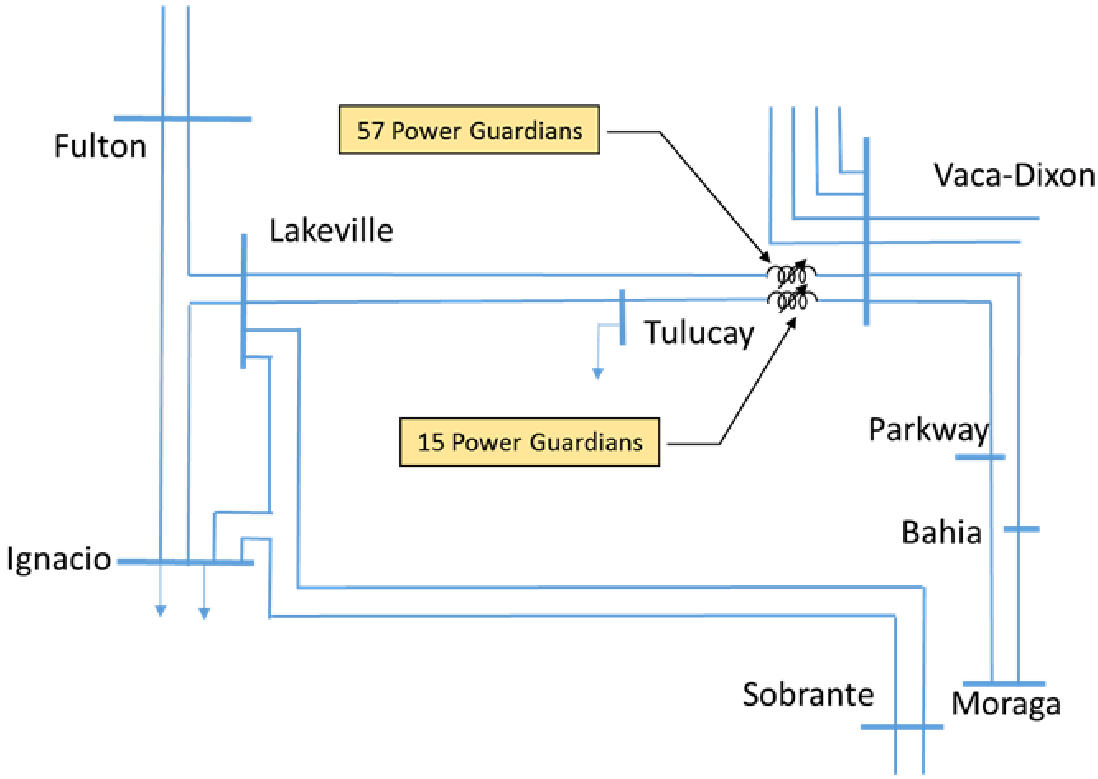
The ISO has evaluated the alternative of reconductoring the Ignacio- San Rafael #1 115 kV Line and the San Rafael Jct – Greenbrae line section of the Ignacio – Alto 60 kV Line as well as upgrading limiting equipment on lines, adding a 10-20 Mvar shunt capacitor at Greenbrae 60 kV Substation and reconductoring the Ignacio- San Rafael #3 115 kV Line and upgrading limiting equipment.

This alternative mitigates identified reliability issues at the much lower cost of $37 million dollars compared to this project.

*Request Window Submission – Vaca Dixon – Lakeville Corridor Smart Wires Project*

Smart Wires, Inc proposed the Vaca Dixon – Lakeville Corridor Smart Wires Project, targeting thermal overloads on the Vaca Dixon – Lakeville 230 kV line and Vaca Dixon – Tulucay 230 kV Line. The project scope is to install 0.39 Ω/phase of Smart Wires devices on both Vaca Dixon – Lakeville and the Vaca Dixon – Tulucay 230 kV Lines.

Table 2.5-8: Vaca Dixon – Lakeville Corriddor Smart Wires Proposl




The estimated cost of this project is between $8.5 and $11 million and the in-service date is October 2027. The ISO has identified this project as a feasible alternative for the "Vaca-Lakeville 230 kV Corridor Series Compensation" project being recommended for approval in this cycle.

### 2.5.2.5 *Consideration of Preferred Resources and Energy Storage*

As presented in section 2.5.2, about 54 MW of AAEE and more than 113 MW of installed behind-the-meter PV reduced the North Coast North Bay Area load in 2022. This year's reliability assessment for North Coast North Bay Area included a "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 69 MW less behind-the-meter PV output. A comparison between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that following facility overloads are potentially avoided due to the reduction in net load:

Table 2.5-9: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Clear Lake – Granite 60 kv Line | P3 |
| Fulton - St. Helena 60 kV Line | P3 |
| Petaluma C Jct - Petaluma A 60 kV Line | P5 |
| Lakeville- Lakeville Jct 60 kV Line | P5 |
| Tulucay – Vaca Dixon 230 kV Line | P6 |
| Lakeville – Vaca Dixon 230 kV Line | P6 |
| Corona - Lakeville 115 kV Line | P6 |
| Fulton - St. Helen 60 kV Line | P6 |
| Corona - Lakeville 115 kV Line | P7 |
| San Rafael - Greenbrae 60 KV Line | P7 |

Furthermore, about 13 MW of demand response and 10 MW of battery energy storage are modeled in North Coast North Bay Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, but didn’t completely alleviate the overloads.

### 2.5.2.6 *Recommendation*

Based on the studies performed for the 2016-2017 Transmission Plan, several reliability concerns were identified for the PG&E North Coast North Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the North Coast North Bay area.

For the areas identified that require additional mitigation, the ISO found the following two new projects to be needed:

1. Lakeville 60 kV Area Reinforcement
2. Vaca-Lakeville 230 kV Corridor Series Compensation

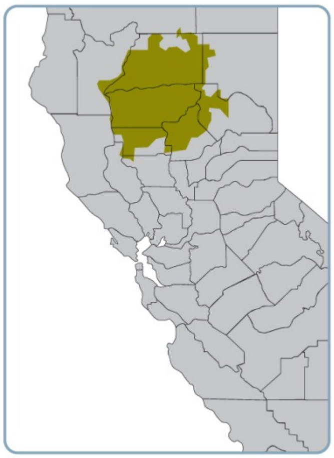
The ISO has recommended the Vaca Dixon-Lakeville 230 kV Corridor Series Compensation project for approval and the Smartwires alternative Smart Wires alternative submitted into the request window can be considered by PG&E for providing the required series compensation.

In regards to the previously-approved project, 5 projects were not modeled in the study cases with four of the projects recommended to proceed with revised scopes and one project is recommended to be canceled.

## 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 as well as 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 local electricity demand. In addition to the Pacific Intertie, one other external interconnection exists connecting 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. Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions.

### 2.5.3.2 *Area-Specific Assumptions and System Conditions*

The North Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured marker participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Valley Area study are provided below.

Table 2.5-10: North Valley load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| NVLY-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 892 | 14 | 163 | 54 | 824 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 511 |
| NVLY-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 924 | 23 | 188 | 63 | 838 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 482 |
| NVLY-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 991 | 39 | 272 | 93 | 859 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 384 |
| NVLY-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 271 | 10 | 163 | 0 | 261 | 36 | 28 | 0 | 0 | 0 | 103 | 10 | 1,774 | 203 | 1,065 | 311 |
| NVLY-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 419 | 19 | 188 | 177 | 223 | 36 | 28 | 0 | 0 | 0 | 103 | 103 | 1,774 | 896 | 1,065 | 210 |
| NVLY-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 883 | 14 | 163 | 33 | 835 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 437 |
| NVLY-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 998 | 39 | 272 | 25 | 934 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 413 |
| NVLY-2022-SP-PS-AAEE | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 915 | 0 | 188 | 24 | 891 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,662 | 1,065 | 479 |
| NVLY-2022-SP-HiRenew | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 796 | 20 | 188 | 188 | 588 | 36 | 28 | 0 | 0 | 0 | 103 | 103 | 1,774 | 1,618 | 1,065 | 285 |
| NVLY-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 991 | 39 | 272 | 93 | 859 | 36 | 28 | 0 | 0 | 0 | 103 | 34 | 1,774 | 1,647 | 1,065 | 399 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of following approved projects which are not modeled in the base cases:

Table 2.5-11: North Valley approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Cascade 115/60 kV No2 Transformer Project and Cascade – Benton 60 kV Line Project | 2010-2011 TPP | Jul-2019 |
| Glenn #1 60 kV Reconductoring | 2009 TPP | Apr-2021 |
| Glenn 230/60 kV Transformer No 1 Replacement | 2013-2014 TPP | Jun-2019 |
| Table Mountain – Sycamore 115 kV Line | 2010-2011 TPP | Dec-2025 |
| Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project | 2011-2012 TPP | Jan-2024 |
| Cottonwood 115 kV Substation Shunt Reactor | 2015-2016 TPP | Nov-2019 |
| Delevan 230 kV Substation Shunt Reactor | 2015-2016 TPP | Dec-2019 |

#### 2.5.3.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E North Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P1 to P7 contingencies most of which are addressed by previously-approved projects. The remaining issues are only under sensitivity scenario and in the long term so ISO continues to monitor those issues and will mitigate them if the issues are identified in future assessments.

*Summary of review of previously-approved projects*

There are 7 previously-approved active projects in the North Valley Area and these projects were not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The table below sets out the ISO's recommendations for the 7 projects not modeled in the study cases:

Table 2.5-12: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Delevan 230 kV Substation Shunt Reactor | Proceed with current scope |
| Glenn 230/60 kV Transformer No 1 Replacement | Proceed with current scope |
| Glenn #1 60 kV Reconductoring | Cancel |
| Table Mountain – Sycamore 115 kV Line | Cancel and install SPS |
| Cottonwood 115 kV Substation Shunt Reactor | Revised scope |
| Cascade 115/60 kV No2 Transformer Project and Cascade – Benton 60 kV Line Project | Revised scope |
| Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project | Revised scope |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussions of projects recommended to proceed with revised scopes:

*Cottonwood 115 kV Substation Shunt Reactor*

Original Scope:

- Install a 100 Mvar shunt reactor at Cottonwood 115 kV substation.
- 2015-2016 TPP estimated cost: $15 to $19 million
- Current estimated cost: $10 to $20 million

Revised Scope:

- Based on the information received from PG&E, the existing bus requires re-build to accommodate the new reactor. In addition, the existing 230/115 kV transformers at the Cottonwood Substation do not have LTC and one of them is built in 1955. PG&E's cost estimate to replace the existing transformers with 2 new transformers with LTC was lower than re-building the bus. ISO's technical assessment confirmed that two transformers with LTC would have similar performance as the shunt reactor at a lower cost. Therefore the revised scope is to replace the transformers.
- 2017-2018 TPP estimated cost: $15 million
- In-service Date: 2021

*Cascade 115/60 kV No2 Transformer Project and Cascade – Benton 60 kV Line Project*

Original Scope:

- Add a second 115/60 kV transformer at Cascade, build Cascade – Benton 60 kV line
- Add high side breaker to the existing 115/60 kV transformer at Cascade.
- 2010-2011 TPP estimated cost: $20 to $30 million
- Current estimated cost: $10 to $20 million

Revised Scope:

- No reliability need was identified for the Cascade – Benton 60 kV Line portion of the project. Therefore the revised scope excludes the Cascade-Benton 60 kV line but retains adding the second transformer at Cascade and the high side breaker to the existing transformer. It is recommended to rename the poejct to Cascade 115/60 kV No. 2 Transformer project
- 2017-2018 TPP estimated cost: $10 to $20 million
- In-service Date: 2020

*Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project*

Original Scope:

- Build a 230/60 kV substation near Red Bluff.
- Connect Red Bluff and Tyler substations to the new substation with new 60 kV lines.
- 2010-2011 TPP estimated cost: $43 to $57 million
- Current estimated cost: $200 to $300 million

Revised Scope:

- Based on this year's reliability assessment there is no need for a new source in the area and the issue could be addressed by reconductoring the Coleman – Red Bluff and Cottonwood – Red Bluff 60 kV lines. The reconductoring of Cottonwood – Red Bluff line is done as part of a PG&E capital maintenance project due to the asset's condition. The Coleman-Red Bluff reconductoring is being retained as the revised scope and the recommendation is to rename the project to Red Bluff-Coleman 60 kV Reinforcement project.
- 2017-2018 TPP estimated cost: $40 Million
- In-service Date: 2021

### 2.5.3.4 *Request Window Submissions*

There were no project submissions in the North Valley area in the 2017 request window.

### 2.5.3.5 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1, about 23 MW of AAEE and around 190 MW of installed behind-the-meter PV reduced the North Valley Area load in 2022 by about 9%. This year's reliability assessment for North Valley Area included "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 40 MW less behind-the-meter PV output. Comparison between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-13: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Cascade - Cottonwood 115 kV Line | P6 |
| Palermo - Wyandotte 115 kV Line | P6 |
| Keswick - Cascade 60 kV | P2 |
| Sycamore Creek - Notre Dame - Table Mountain 115 kV Line | P2 |
| Table Mountain - Butte #1 115 kV | P2 |
| Paradise - Table Mountain 115 kV | P2 |

Furthermore, more than 36 MW of demand response is modeled in North Valley Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

### 2.5.3.6 *Recommendation*

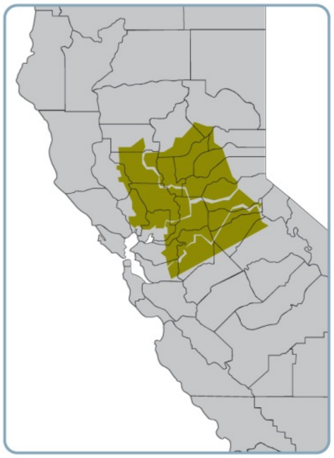
Based on the studies performed in the 2017-2018 transmission planning cycle, several reliability concerns were identified for the PG&E North Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the North Valley area.

No project was submitted through Request Window in the North Valley Area in this cycle. In regards to the previously-approved projectw, 7 projects were not modeled in the study cases; no changes are recommended for two projects, two projects are recommended to be canceled, and revised scopes were found to be needed for three 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*

The 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 Electric. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

*Sierra Division*

The 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 kV, 115 kV and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 kV and 230 kV facilities transmit generation resources from north-to-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*

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 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. 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*

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 kV, 115 kV 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 area experiences its highest demand during the summer season. Accordingly, system assessments in these areas included technical studies using load assumptions for the summer peak conditions.

#### 2.5.4.2 *Area-Specific Assumptions and System Conditions*

The Central Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are provided below.

Table 2.5-14 Central Valley load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| CVLY-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3,865 | 96 | 688 | 229 | 3,540 | 101 | 59 | 34 | 46 | 12 | 1,376 | 454 | 1,389 | 1,101 | 1,501 | 1,188 |
| CVLY-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3,995 | 159 | 807 | 273 | 3,563 | 103 | 59 | 34 | 46 | 12 | 1,376 | 454 | 1,389 | 1,099 | 1,501 | 1,181 |
| CVLY-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 4,246 | 272 | 1,162 | 398 | 3,577 | 104 | 59 | 34 | 46 | 12 | 1,376 | 454 | 1,389 | 1,095 | 1,501 | 1,171 |
| CVLY-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 1,354 | 66 | 688 | 0 | 1,288 | 101 | 59 | 34 | 46 | 0 | 1,376 | 138 | 1,389 | 891 | 1,501 | 1,237 |
| CVLY-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 2,046 | 127 | 807 | 763 | 1,156 | 103 | 59 | 34 | 46 | 46 | 1,376 | 1,376 | 1,389 | 742 | 1,501 | 335 |
| CVLY-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 3,835 | 96 | 688 | 142 | 3,597 | 101 | 59 | 34 | 46 | 7 | 1,376 | 454 | 1,389 | 1,133 | 1,501 | 1,188 |
| CVLY-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 4,072 | 272 | 1,162 | 107 | 3,693 | 104 | 59 | 34 | 46 | 3 | 1,376 | 454 | 1,389 | 1,133 | 1,501 | 1,054 |
| CVLY-2022-SP-PS-AAEE | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 3,958 | 0 | 807 | 105 | 3,853 | 103 | 59 | 34 | 46 | 4 | 1,376 | 454 | 1,389 | 1,133 | 1,501 | 1,053 |
| CVLY-2022-SP-HiRenew | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 3,433 | 138 | 807 | 807 | 2,488 | 103 | 59 | 34 | 46 | 46 | 1,376 | 1,376 | 1,389 | 1,091 | 1,501 | 305 |
| CVLY-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 4,246 | 272 | 1,162 | 398 | 3,577 | 104 | 59 | 34 | 46 | 12 | 1,376 | 454 | 1,389 | 1,085 | 1,501 | 1,181 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of following approved projects which are not modeled in the base cases:

Table 2.5-15: Central Valley approved projects not modeled in base case

| **Project Name** | **TPP Approved In** | **Current ISD** |
|---|---|---|
| Atlantic-Placer 115 kV Line | 2012-2013 TPP | Dec-2021 |
| Pease 115/60 kV Transformer Addition and Bus Upgrade | 2012-2013 TPP | Mar-2020 |
| Mosher Transmission Project | 2013-2014 TPP | Oct-2019 |
| Bellota 230 kV Substation Shunt Reactor | 2015-2016 TPP | Dec-2020 |
| Vaca – Davis Voltage Conversion Project | 2010-2011 TPP | Apr-2025 |
| Rio Oso – Atlantic 230 kV Line Project | 2010-2011 TPP | Dec-2022 |
| Vierra 115 kV Looping Project | 2010-2011 TPP | Nov-2021 |
| Stagg – Hammer 60 kV Line | 2010-2011 TPP | Aug-2022 |
| Rio Oso Area 230 kV Voltage Support | 2011-2012 TPP | Apr-2021 |
| Lockeford-Lodi Area 230 kV Development | 2012-2013 TPP | Dec-2022 |

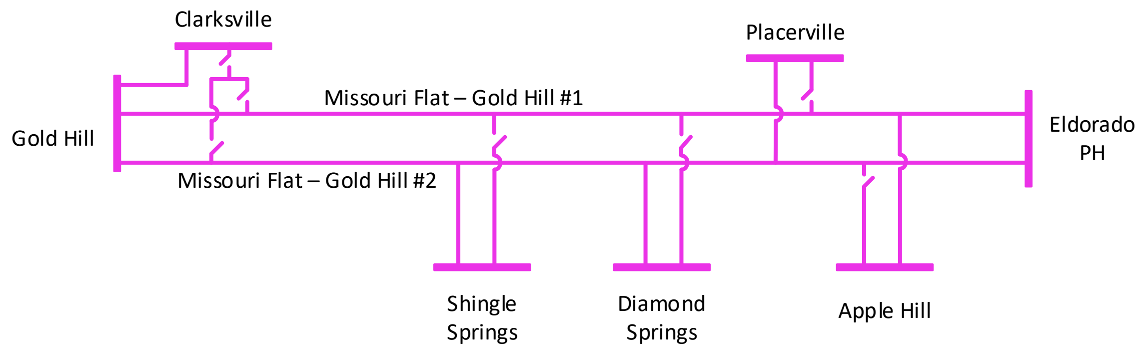
### 2.5.4.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

*Gold Hill – El Dorado PH 115 kV system*

Category P2-1 contingency overloads are identified on the Gold Hill – El Dorado PH 115 kV system. As shown in the diagram below, majority of the load pockets in the area are connected to Missouri Flat – Gold Hill #2 line. As a result, P2-1 overload occurs when the breaker at the Gold Hill end of the Missouri Flat – Gold Hill #2 line opens without a fault. Under this scenario, significant power will flow on Missouri Flat – Gold Hill #1 to supply all the load which will result in overload on the sections connected to El Dorado PH that have lower ratings.

Table 2.5-16: Gold Hill – El Dorado PH 115 kV system




To address the issue, ISO is recommending that as normal operation, the Shingle Springs load to be connected to Missouri Flat – Gold Hill #1.

### *Summary of review of previously-approved projects*

There are 18 previously-approved active projects in the Central Valley Area, out of which 10 projects are not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The 8 projects modeled in the study cases were found to have current needs consistent with the scope of the projects and no changes to those projects are recommended. Table below shows final recommendation for the 10 projects not modeled in the study cases:

Table 2.5-17: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Bellota 230 kV Substation Shunt Reactor | Proceed with current scope |
| Vierra 115 kV Looping Project | Proceed with current scope |
| Rio Oso – Atlantic 230 kV Line Project | Cancel |
| Stagg – Hammer 60 kV Line | Cancel and install SPS |
| Atlantic-Placer 115 kV Line | Hold |
| Vaca – Davis Voltage Conversion Project | Revised scope |
| Pease 115/60 kV Transformer Addition and Bus Upgrade | Revised scope |
| Mosher Transmission Project | Revised scope |
| Rio Oso Area 230 kV Voltage Support | Revised scope |
| Lockeford-Lodi Area 230 kV Development | Revised scope |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussion of projects recommended to proceed with revised scope:

*Stagg – Hammer 60 kV Line*

The 2017-2018 reliabity assessment identified overloads for P2, P6, and P7 contingencies on the 60 kV system. The recommendation is to cancel the project and recommend PG&E to install a SPS to address the issue.

*Atlantic-Placer 115 kV Line*

The ISO is going to continue the review of the overall system needs in this area in the next planning cycle and evaluate alternatives that could potentially address all the issues in the area. The project was put on hold in the 2016-2017 TPP and is recommended to remain on-hold with further detailed assessment of the project and potential alternatives in the 2018-2019 TPP.

*Vaca – Davis Voltage Conversion Project*

There are overloads and voltage criteria violations in the 115 kV and 60 kV transmission system between Vaca Dixon, Davis, Rio Oso, and Brighton substations. However due to drop in load forecast, the criteria violations are not as severe compared to 2010-2011 TPP analysis when the Vaca – Davis Votlage Conversion Project was approved. The ISO is recommending approval of the "Vaca – Davis Voltage Conversion Project" (revised scope) and to rename the project to "Vaca Dixon Area Reinforcement".

Original Scope:

- Convert the 60 kV network between Vaca Dixon to Davis to 115 kV.
- 2010-2011 TPP estimated cost: $70 to $107 million
- Current estimated cost: $192 million

Revised Scope:

- Install 10 Mvar capacitor bank at Plainfield substation (2 x 5 Mvar capacitor banks)
- Replace Vaca Dixon 115/60 kV Bank #5 with higher rating transformer
- Replace the limiting elements of Dixon 60 kV substation
- Recommend PG&E to re-rate the Woodland – Davis 115 kV line and Rio Oso – West Sac 115 kV line and recommend PG&E to modifying existing SPSs or add new SPS to trip load for the P6 contingencies.
- 2017-2018 TPP estimated cost: $15 Million
- In-service Date: 2021

*Pease 115/60 kV Transformer Addition and Bus Upgrade*

Thermal overload and voltage criteria violations were identified in the Pease area in this reliability assessment. This assessment also determined that a UVLS that was part of the original scope of the project is no longer required. The ISO is recommending approval of the "*Pease 115/60 kV Transformer Addition and Bus Upgrade*" (revised scope).

Original Scope:

- Add a 115/60 kV transformer at Pease
- Install UVLS in the interim.
- 2012-2013 TPP estimated cost: $25 to $35 million
- Current estimated cost: $30 to $30 million

Revised Scope:

- Add a 115/60 kV transformer at Pease. No need for UVLS was identified in this year's assessment.
- 2017-2018 TPP estimated cost: $20 to $30 million
- In-service Date: 2019

*Mosher Transmission Project*

This project was approved in 2013-2014 TPP based on ISO Planning Standard with regards to Planning for New Transmission vs. Involuntary Load Interruption. The latest assessment has determined that 2x715 AAC conductor is no longer required and therefore the ISO is recommending revising the scope of the project.

Original Scope:

- Reconductor the Lockeford No. 1 60 kV line with 2x715 AAC conductor.
- 2013-2014 TPP estimated cost: $10 to $15 million
- Current estimated cost: $10 to $20 million

Revised Scope:

- Reconductor the Lockeford No. 1 60 kV line with single 715 AAC conductor.
- 2017-2018 TPP estimated cost: $15 Million
- In-service Date: 2019

*Rio Oso Area 230 kV Voltage Support*

This reliability assessment identified that a larger SVC is needed (+200/-260 MVA) at Rio Oso 230 kV bus to address voltage issues under light load conditions. The reliability assessment identified that the capacitor bank at the Atlantic 230 kV substation is no longer requred. With this the project is recommended to proceed with the revised scope below.

Original Scope:

- Install a +200/-175 MVA SVC at Rio Oso 230 kV bus.
- Install a capacitor bank at Atlantic 230 kV substation.
- 2011-2012 TPP estimated cost: $35 to $45 million
- Current estimated cost: $24 million

Revised Scope:

- Install a +200/-260 MVA SVC at Rio Oso 230 kV bus.
- 2017-2018 TPP estimated cost: $24 milion
- In-service Date: 2022

*Lockeford-Lodi Area 230 kV Development*

This reliability assessment identified thermal overload and voltage issues on the 60 kV network between Lockeford and Industrial substations following P1 contingencies. This reliability assessment identified that the double circuit 230 KV line from Industrial to Eight Mile substations is no longer required. The ISO is recommending the revised scope of the "*Lockeford-Lodi Area 230 kV Development*".

Original Scope:

- A double circuit 230 kV line from Lockeford to Eight Mile
- Loop in one of the lines at a new Lodi 230 kV substation.
- 2012-2013 TPP estimated cost: $80 to $105 million
- Current estimated cost: $166 to $166 million

Revised Scope:

- Loop in the Brighton – Bellota 230 kV line into the Lockeford substation
- A double-circuit 230 kV line from Lockeford to a new Industrial 230 kV switching station.
- 2017-2018 TPP estimated cost: $89 million
- In-service Date: 2023

#### 2.5.4.4 *Request Window Submissions*

*NEER - Lodi 40MW BESS Project*

NextEra Energy Resources, LLC (NEER) proposed the Lodi 40 MW BESS to address thermal overloads on the 60 kV system between Lockeford, Lodi, and industrial substations. The Lodi BESS project is a 41.80 MW, 4 hours (167.20 MWh) storage system with an estimated cost of $60 Million in 2022 dollars.

While this project addresses the identified thermal overloads, there are other lower cost alternatives that address reliability issues and therefore the ISO determined that the Lodi 40 MW BESS is not the preferred alternative for reliability purposes.

*NEET West Lockeford - Industrial Transmission Reliability Project*

NextEra Energy Transmission West proposed the Lockeford - Industrial Transmission Reliability Project to address thermal overload issues in the industrial area. While this project addresses some of the thermal overload issues in the area,it does not address the voltage issues in the area. Therefore the ISO determined that the Lockeford - Industrial Transmission Reliability Project is not the preferred alternative for reliability purposes. ISO's recommended solution to address all the reliabliy  issues in the area in a cost effective manner is to revised scope of the previously-approved Lockeford – Lodi 230 kV Development project. More details are provided in the review of the Lockeford-Lodi Area 230 kV Development project ealier in this report.

*Calpine - Feather River Energy Center Clutch*

Calpine Corporation submitted a proposal to install a clutch between the turbine and the generator of the Feather Reiver Energy Center to be able to run the generator as synchronous condenser. The cost estimate for the project is $6M-$7M and an outage of approximately 45 days is required to install the clutch and accessory equipment.

The Feather River Energy Center (FREC) unit is currently relied upon in real time operation to address voltage issues in the Bogue area, where real time data shows very high voltages mostly under light load condition. To ensure availability of FREC to address voltage issues, the ISO has designated FREC as reliability must-run generation in 2018.

These voltage issues will be addressed when Rio Oso Transformer Upgrade Project and the power factor correction program initiated by PG&E are implemented. The Rio Oso Area 230 kV Voltage Support project will help to address the issue as well.

Until those other projects are in place, and with the existing configuration of the FREC unit, FREC has to generate real power at least equal to its Pmin of 20 MW for stable turbine operation any time it is dispatched for voltage control reasons. The clutch would decouple the generator and turbine and allow the the generator to operate as synchronous condenser independent of the turbine.

The ISO reviewed the proposed clutch project and determined that having the clutch in service will not eliminate the need or reduce the scope of the Rio Oso Transformer Upgrade Project and the Rio Oso Area 230 kV Voltage Support project. Therefore from reliability perspective there is no long term need for this project, and the project was not found to be needed.

### 2.5.4.5 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1, about 160 MW of AAEE and more than 800 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2022 by about 11%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 170 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-18: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Drum - Higgins 115 kV line | P7 |
| Stanislaus-Melones-Manteca 115 kV Line No. 1 | P2 |
| Tesla - Tracy 115 kV Line | P2, P6 |
| Eldorado - Missouri Flat 115 kV No. 1 Line | P2-1 |
| Stanislaus-Melones-Manteca 115 kV Line | P2 |
| Bellota - Riverbank - Melones 115KV Line | P2 |
| Stanislaus-Melones-Riverbank 115 kV Line | P2 |
| Drum - Grass Valley - Weimar 60 kV Line | P3 |

Furthermore, more than 100 MW of demand response and 34 MW of battery energy storage are modeled in the Central Valley Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

### 2.5.4.6 *Recommendation*

Based on the studies performed for the 2017-2018 Transmission Plan, several reliability concerns were identified for the PG&E Central Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the Central Valley area.

Out of the four projects submitted through Request Window in the Central Valley Area in this cycle, the ISO found the need for one; the Lockeford – Industrial 230 kV line project which will be accomplished as scope change to the currently approved Lockeford – Lodi Area 230 kV Development project. In regards to the 10 previously-approved projects not modeled in the study cases, the ISO found that two projects should proceed with their current scopes, two projects may be canceled, one project on holde and revised scopes have been developed for five projects.

## 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 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, Calpine Gilroy Power 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. Lastly, 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 that include the 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.

Trans Bay Cable became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The line employs voltage source converter technology, which will transmit 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.

The ISO Planning Standards were enhanced in 2014 to recognize that the unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages for extreme events that are beyond the level that is applied to the rest of the ISO controlled grid.

### 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Greater Bay Area study are provided below.

Table 2.5-19 Greater Bay Area load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| GBA-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 8,583 | 239 | 1,011 | 336 | 8,008 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,507 |
| GBA-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 8,809 | 389 | 1,303 | 441 | 7,980 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,517 |
| GBA-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 9,251 | 669 | 2,145 | 734 | 7,848 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,528 |
| GBA-2019-WP | Baseline | 2019 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 8,128 | 245 | 1,011 | 0 | 7,883 | 161 | 73 | 4 | 25 | 0 | 259 | 108 | 0 | 0 | 6,850 | 4,166 |
| GBA-2022-WP | Baseline | 2022 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 8,335 | 402 | 1,303 | 0 | 7,933 | 161 | 73 | 4 | 25 | 0 | 259 | 96 | 0 | 0 | 6,850 | 3,289 |
| GBA-2027-WP | Baseline | 2027 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 8,748 | 708 | 2,145 | 0 | 8,040 | 161 | 73 | 4 | 25 | 0 | 259 | 119 | 0 | 0 | 6,850 | 4,432 |
| GBA-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 4,644 | 164 | 1,011 | 0 | 4,480 | 161 | 73 | 4 | 25 | 0 | 259 | 24 | 0 | 0 | 6,850 | 2,093 |
| GBA-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 7,141 | 305 | 1,303 | 1,231 | 5,605 | 161 | 73 | 4 | 25 | 25 | 259 | 238 | 0 | 0 | 6,850 | 1,189 |
| GBA-2022-SP-PS-A | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 8,902 | 0 | 1,303 | 169 | 8,732 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,516 |
| GBA-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 8,687 | 239 | 1,011 | 207 | 8,241 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,401 |
| GBA-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 9,290 | 669 | 2,145 | 197 | 8,424 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,556 |
| GBA-2022-SP-HiRe | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 8,759 | 339 | 1,303 | 441 | 7,980 | 161 | 73 | 4 | 25 | 25 | 259 | 238 | 0 | 0 | 6,850 | 2,150 |
| GBA-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 9,251 | 669 | 2,145 | 734 | 7,848 | 161 | 73 | 4 | 25 | 6 | 259 | 79 | 0 | 0 | 6,850 | 4,530 |

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3 with an exception of following previously-approved projects which are not modeled in the base cases:

Table 2.5-20: Greater Bay Area approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Metcalf-Evergreen 115 kV Line Reconductoring | 2001 TPP | May-2019 |
| Los Esteros 230 kV Substation Shunt Reactor | 2015-2016 TPP | Oct-2019 |
| Ravenswood – Cooley Landing 115 kV Line Reconductor | 2009 TPP | Dec-2020 |
| Los Esteros-Montague 115 kV Substation Equipment Upgrade | 2012-2013 TPP | Mar-2021 |
| Moraga-Castro Valley 230 kV Line Capacity Increase Project | 2010-2011 TPP | Mar-2021 |
| Spring 230/115 kV substation near Morgan Hill | 2013-2014 TPP | Oct-2022 |
| Evergreen-Mabury Conversion to 115 kV | 2009 TPP | Jun-2021 |
| San Mateo – Bair 60 kV Line Reconductor | 2009 TPP | May-2023 |
| South of San Mateo Capacity Increase | 2007 TPP | Feb-2029 |
| Jefferson - Stanford #2 60 kV Line | 2010-2011 TPP | On Hold |

### 2.5.5.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Greater Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

*East Bay Area Long-Term Need without Local Generation*

Category P2 and P6 contingency overloads are identified in the Oakland 115 kV system without local generation. The P2 overloads are driven by breaker or bus outages at Moraga and Oakland X stations. Whereas the P6 overloads are driven by loss of the two C-X 115 kV cables or one of the C-X 115 kV cable combined with loss of D-L 115 kV cable. To mitigate these overloads, the ISO is recommending approval of the “Oakland Clean Energy Initiative” project submitted by PG&E in the 2017 Request Window. The project is discussed in detail in Section 2.5.5.4.

*Newark-Lawrence 115 kV Line Limiting Facility Upgrade*

Category P6 and P7 contingency overloads were identified on the Newark-Lawrence 115 kV line. The overloaded section of the line is limited by the circuit breaker at the Newark substation. The ISO is recommending the approval of the Newark-Lawrence 115 kV Line Limiting Facility Upgrade project which includes upgrading the limiting substation equipment. The stimated cost of this project is between $1.5M to $2.0M and the in-service date is December 2018.

*San Jose-Trimble 115 kV Line Limiting Facility Upgrade*

A Category P6 contingency overload was identified on the San Jose-Trimble 115 kV line. The overloaded section of the line is limited by the rating of jumper conductors. The ISO is recommending approval of the Trimble-San Jose B 115 kV Line Limiting Facility Upgrade project which includes upgrading the limiting substation equipments. The estimated cost of this project is between $250K and the in-service date is December 2018.

*Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade*

A Category P6 contingency overload was identified on the Newark-Milpitas #1 115 kV Line. The overloaded section of the line is limited by circuit breaker and terminal conductor ratings. The ISO is recommending approval of the Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade project which includes upgrading the limiting substation equipment. The estimated cost of this project is between $1.5M to $2.0M and the in-service date is June 2019.

*Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate*

Category P2, P6 and P7 contingency overloads were identified on the Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines. These lines currently have thermal ratings based on two feet per second wind speed assumptions. The ISO is recommending approval of the Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate project which includes rerating of these lines based on four feet per second wind speeds. The rerating of these lines is expected to cost around $1M and the in-service date is February 2019.

*Oleum-Martinez 115 kV system*

Category P2 and P7 contingency overloads were identified in the Oleum-Martinez 115 kV system. The P2 overloads are due to loss of supply from Sobrante. The P7 overloads are due to the loss of Sobrante-G 115 kV DCTL. To mitigate these overloads, the ISO is working with PG&E to develop a project which could include substation upgrade at Sobrante 115 kV and reconductoring of the Christie-Sobrante 115 kV line.

### *Summary of review of previously-approved projects*

There are 20 previously-approved active projects in the Greater Bay Area, of which 10 projects are not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The 10 projects modeled in the study cases were found to have current needs consistent with the scope of the project and no changes to their current scopes are recommended. The table below shows the recommendations for the 10 projects not modeled in the study cases:

Table 2.5-21: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Metcalf-Evergreen 115 kV Line Reconductoring | Proceed with current scope |
| Los Esteros 230 kV Substation Shunt Reactor | Proceed with current scope |
| Ravenswood – Cooley Landing 115 kV Line Reconductor | Proceed with current scope |
| Moraga-Castro Valley 230 kV Line Capacity Increase Project | Proceed with current scope |
| Los Esteros-Montague 115 kV Substation Equipment Upgrade | Cancel |
| Evergreen-Mabury Conversion to 115 kV | Cancel |
| San Mateo – Bair 60 kV Line Reconductor | Cancel |
| Spring 230/115 kV substation near Morgan Hill | Revised scope |
| South of San Mateo Capacity Increase | Revised scope |
| Jefferson - Stanford #2 60 kV Line | Hold |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussions of projects recommended to proceed with revised scopes:

*Spring 230/115 kV substation near Morgan Hill*

Category P6 contingency overloads were observed on the Metcalf-Llagas and Metcalf-Morgan Hill 115 kV lines in summer peak cases and multiple sensitivity scenarios. P6 contingency driven low voltages in Llagas and Morgan Hill substations were also observed in multiple sensitivity cases including the 2027 peak shift sensitivity. To mitigate these overloads and low voltage issues, the ISO is recommending approval of the “Spring 230/115 kV substation near Morgan Hill” (revised scope) and to rename the project to “*Morgan Hill Area Reinforcement* “.

Original Scope:

- New 230/115 kV substation.
- Loop the existing Morgan Hill-Llagas 115 kV line into the Spring 115 kV substation bus, reconductor the Spring-Llagas 115 kV line and loop the Metcalf-Moss Landing No.2 230 kV line into the Spring 230 kV bus
- 2013-2014 TPP estimated cost: $35 to $45 million
- Current cost of Watsonville project: $40 to $70 million
- Current estimated cost: $250 to $350 million

Revised Scope:

- Rebuild Metcalf - Green Valley 115 kV into the Green Valley - Morgan Hill 115 kV (all new structures; 15 miles).
- Rebuild Morgan Hill 115 kV into a breaker-and-a-half configuration.
- 2017-2018 TPP estimated cost: $72 to $104 million
- In-service Date: May 2021

*South of San Mateo Capacity Increase*

Category P6 contingency overloads were observe on the south of San Mateo 115 kV lines in winter peak cases and multiple sensitivity scenarios including the two 2019 and 2027 peak-shift scenarios. To mitigate these overloads, the ISO is recommending approval of the "*South of San Mateo Capacity Increase*" (revised scope).

Original Scope:

- Reconductor the Newark-Ames and San Mateo-Ravenswood 115 kV Lines with higher capacity conductors and substation equipment, as needed.
- 2007 TPP estimated cost: $10 to $20 million
- Current estimated cost: $80 to $200 million

Revised Scope:

- Normally close the Monta Vista-AMES 115 kV Path.
- Reconductor the San Mateo-Ravenswood 115 kV line.
- 2017-2018 TPP estimated cost: $15 to 15 million
- In-service Date: Monta Vista-AMES 115 kV path closing – January 2019
  San Mateo-Ravenswood Reconductoring – March 2026

#### 2.5.5.4 *Request Window Submissions*

*Request Window Submission - TBC Bi-Directional flow control Upgrade Project*

Trans Bay Cable, LLC (TBC) proposed the TBC Bi-Directional flow control Upgrade, targeting thermal overloads in San Francisco area as a reliability need. The project is an upgrade to enable bi-directional flow control on the VSC HVDC cable. The scope involves upgrading the existing control and protection system with any additional hardware as required, testing and completing the project.

The identified thermal overloads are mitigated either by the existing TBC run back scheme or the TBC run back scheme modification recommended by the ISO in previous TPP cycles. Hence, the ISO determined that the TBC Bi-Directional flow control Upgrade Project is not needed for reliability purposes.

*Request Window Submission - Oakland 40 MW Battery Energy Storage System (BESS)*

NextEra Energy Resources, LLC (NEER) proposed a project, Oakland 40 MW Battery Energy Storage System (BESS), targeting thermal overloads in Oakland area without local generation as reliability need. NEER proposed a 40 MW/4 hour BESS at Oakland C 115 kV substation.

The project as proposed doesn't address all reliability issues identified in the Oakland area without local generation. Hence, the ISO determined that the *Oakland 40 MW Battery Energy Storage System (BESS)* is not appropriate solution for reliability issues identified in Oakland area without local generation.

*Request Window Submission - Oakland 230 kV Transmission System*

NextEra Energy Transmission (NEET) proposed the Oakland 230 kV Transmission System targeting thermal overloads in the Oakland area without local generation as a reliability need. NEET proposed a new 230 kV line from Moraga or Sobrante to Oakland C substation with a 230/115 kV transformer connecting to Oakland C 115 kV substation.

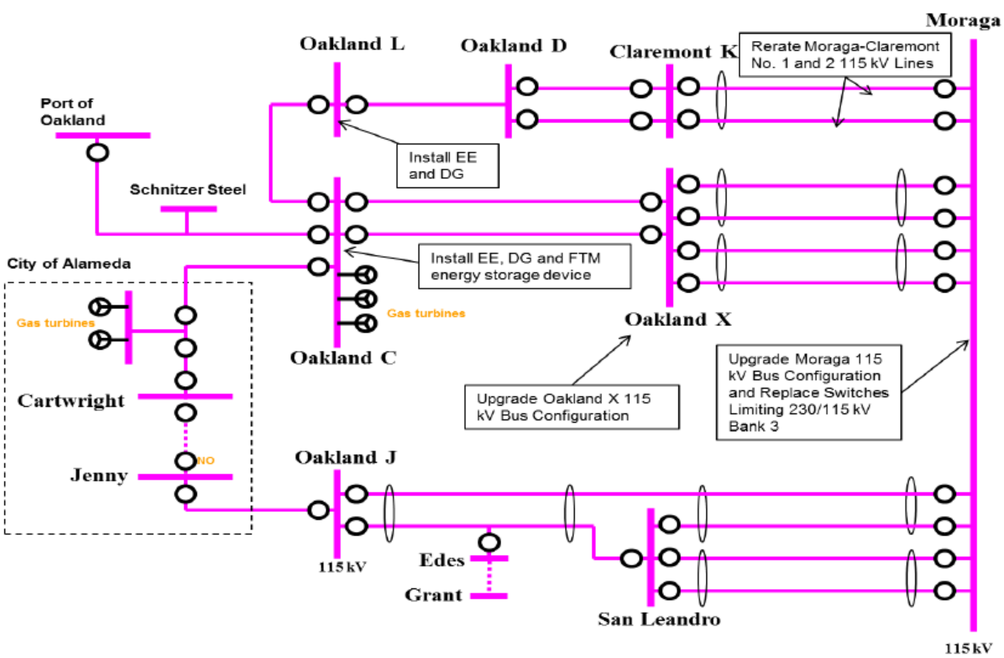
The project as proposed has a higher cost than other alternatives and also doesn't address all reliability issues identified in the Oakland area without local generation. Hence, the ISO determined that the Oakland 230 kV Transmission System is not an appropriate solution for reliability issues identified in the Oakland area without local generation.

*Request Window Submission - Oakland Clean Energy Initiative*

Pacific Gas & Electric (PG&E) proposed the Oakland Clean Energy Initiative (OCEI), targeting thermal overloads in Oakland area without local generation as a reliability need. PG&E proposed a combination of substation upgrades, in-front-of-the-meter energy storage, and preferred resources. The project includes the following:

1. Upgrades to Moraga 230/115 kV Transformer Bank 3 to remove limiting elements, as well as upgrades at Moraga 115 kV and Oakland X 115 kV substation buses;
2. Transmission line rerates on Moraga-Claremont 115 kV Lines #1 and #2, currently underway and scheduled for completion in Q1 2018;
3. A minimum of 10MW / 4 hour of in-front-of-the-meter Utility Owned Energy Storage within the Oakland C and Oakland L 115 kV substation pocket;
4. Competitive procurement of an additional 10 MW-24 MW of preferred resources sited within the Oakland C and Oakland L 115 kV substation pocket, of which at least 19.2 MW (measured at 4 pm in September) must be load modifying in nature; and,
5. Continued reliance on transferring Alameda Municipal Power load from Cartwright (North) to Jenny (South) during peak loading conditions and after an N-1, in preparation for an N-1-1.

Table 2.5-22: Post-OCEI Single Line Diagram:



Alternatives Considered

Generation: 200 MW of generation would adequately address the reliability issues.

115 kV Line Alternative: Three alternatives (Moraga-Maritime 115 kV Line Installation, Moraga-Oakland 'C' 115 kV Line Installation or Moraga-Oakland 'L' 115 KV Line Installation).

230 kV Line Alternative: Request Window submission from NEET West described above; however, note additional upgrades would need to be added to alternative to address the reliability need identified.

Table 2.5-23 provides the estimated cost of the alternatives as well as the present value of revenue requirement estimates.

Table 2.5-23: Estimated Cost of Alternatives

| | Estimated Capital Cost (2022 $M) | Total Cost (2022 $M) |
|---|---|---|
| OCEI | $56-$73[1] | $102[2] |
| 115 kV | $193-$217 | $367[3] |
| 230 kV | $316 | $574[4] |
| Generation | $232 | $368[5] |

Notes:

1 Proportion of CAPEX to contract spend will be determined by the most cost effective portfolio determined through the RFO
2 Calculated using unit costs of the expected portfolio, including land and O&M as appropriate
3 Based on the $193 CAPEX estimate assuming 2022 installation date
4 Based on the CAPEX estimate assuming 2022 installation date
5 Based on the CAPEX estimate assuming 2022 installation date

The ISO review found that the OCEI project address all reliability issues identified in the Oakland area without local generation. The ISO is recommending the approval of the transmission regulated assets of the Oakland Clean Energy Initiative project for the substation upgrades at Moraga and Oakland X, rerating of Moraga-Claremont 115 kV Lines #1 and #2 and the installation of the battery storage at the Oakland C and Oakland L 115 kV substations that are estimated to cost $56 to $73 million with an in-service date of 2022. The ISO is recommending PG&E to seek approval through the CPUC procurement process the additional identified preferred resources for the Oakland Clean Energy Initiative.

*Request Window Submission - Metcalf - Evergreen No. 1 115 kV Smart Wires Project*

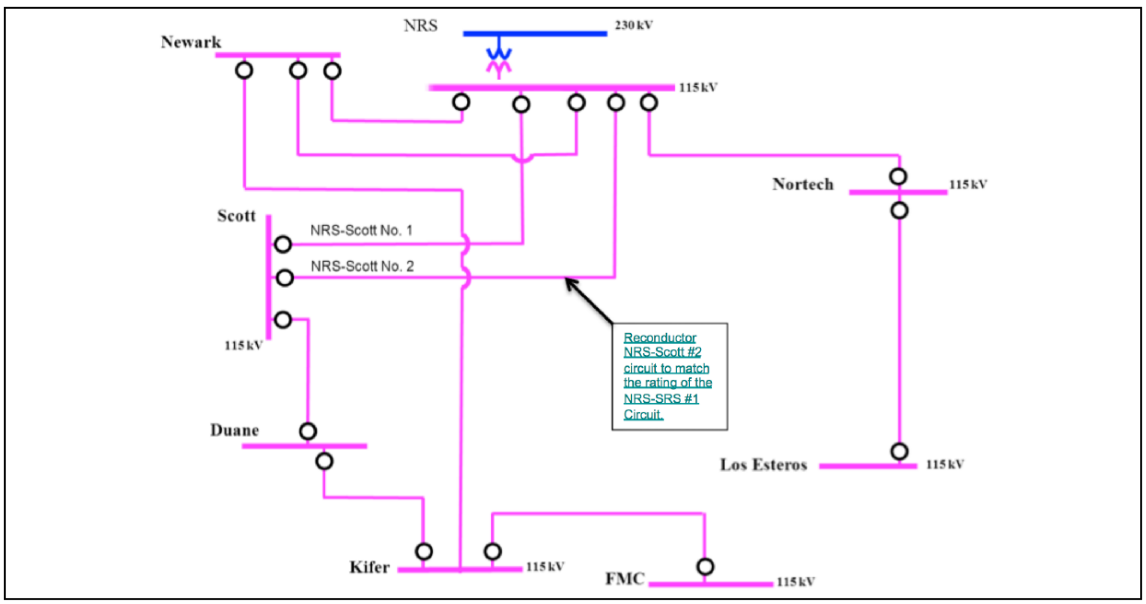
Smart Wires, Inc proposed a project, Metcalf - Evergreen No. 1 115 kV Smart Wires Project, targeting thermal overloads on the Metcalf-Evergreen No. 1 115 kV line without modeling of the previously-approved "Metcalf-Evergreen 115 kV Line Reconductoring". The project proposes to install 0.39 Ω/phase of Smart Wires devices on the Metcalf - Evergreen No. 1 115 kV line.

The project as proposed doesn't address all of the reliability issues identified on the Metcalf-Evergreen 115 kV lines. Hence, the ISO determined that the Metcalf - Evergreen No. 1 115 kV Smart Wires Project is not appropriate solution for reliability issues identified on the Metcalf - Evergreen No. 1 115 kV line.

*Request Window Submission - NRS-Scott No. 2 115 kV Line Reconductor*

Silicon Valley Power (SVP) submitted a project, NRS-Scott No. 2 115 kV Line Reconductor, targeting thermal overloads on the NRS-Scott No. 2 115 kV line. The Project proposes to reconductor the NRS-Scott No. 2 115 kV line.

Table 2.5-24: Proposed Project One Line Diagram




The project as proposed addresses all reliability issues identified on the NRS-Scott No. 2 115 kV line. The ISO recommends to re-scope the previously-approved transmission project "NRS-Scott No. 1 Reconductor Project" to include reconductoring of the No. 2 line as well. Current cost estimate for reconductoring of both lines is between $5-10 million[62].

### 2.5.5.5 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1, about 400 MW of AAEE and more than 1300 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2022 by about 10%. This year's reliability assessment for Greater Bay Area included the "high CEC forecast" sensitivity case for

[62] Cost responsibility between PG&E and SVP has not been resolved – ISO approval does not pre-suppose the outcome of the dispute process underway at FERC.

year 2022 which modeled no AAEE and about 270 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the “high CEC forecast” sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-25: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Los Esteros-Montague 115 kV Line | P6 |
| Metcalf 230/115 kV Trans No. 3 | P2 |
| Metcalf-El Patio No. 2 115 kV Line | P2 |
| Metcalf-Evergreen No. 1 115 kV Line | P2 |
| San Jose 'B'-Stone-Evergreen 115 kV Line | P2 |
| Stone-Evergreen-Metcalf 115kV Line | P2 |
| Stone-Evergreen-Metcalf 115kV Line | P6 |
| Monta Vista 230/115 kV Trans No. 2 | P6 |
| Monta Vista 230/115 kV Trans No. 3 | P6 |
| Monta Vista 230/115 kV Trans No. 4 | P6 |

Furthermore, about 161 MW of demand response and 4 MW of battery energy storage are modeled in the Greater Bay Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn’t completely alleviate the overloads.

Preferred resources as potential mitigation are also identified for areas of additional mitigation requirements as discussed in section 2.5.1.3. The following table lists areas for which preferred resources are identified as recommended solution or as potential mitigation solution for areas currently relying on interim operational action along with high-level size of resource needed to mitigate reliability issues.

Table 2.5-26: Areas preferred resources are identified as recommended solutions

| Area | Category | Need | | Location |
|---|---|---|---|---|
| | | Peak (MW) | Duration (Hr) | |
| Oakland 115 kV | P2 | 19 | 10 | Oakland C, Oakland L |
| | P6 | 38 | 15 | Oakland C, Oakland L |

### 2.5.5.6 *Recommendation*

Based on the studies performed in the 2017-2018 transmission planning cycle Transmission Plan, several reliability concerns were identified for the PG&E Greater Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the Greater Bay area.

Out of the five projects submitted through Request Window in the Greater Bay Area in this cycle, the ISO recommends approval for the Oakland Clean Energy Initiative project and NRS-Scott No. 2 Line Reconductor project. The NRS-Scott No. 2 115 kV Line Reconductoring will be accomplished as scope change to the currently approved NRS-Scott No. 1 115 kV Line Reconductoring project.

For the remaining areas identified for additional mitigation requirement, the ISO recommends approval of following four new projects found to be needed as reliability-driven projects:

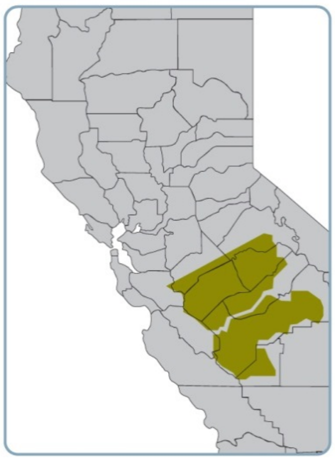
1. Newark-Lawrence 115 kV Line Limiting Facility Upgrade
2. Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade
3. Trimble-San Jose B 115 kV Line Limiting Facility Upgrade
4. Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate

In regards to the previously-approved project, out of 10 projects not modeled in the study cases, no changes were found to be needed for four projects which should proceed with their current scopes, three projects should be canceed, revised scopes have been developed for two projects, and one project should remain on hold.

## 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), several market facilities and a 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 including 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; three 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. The largest generation facility within the area is the Helms plant, with 1212 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. Significant transmission upgrades have been approved in the Fresno area in past transmission plans, which are set out in chapter 7.

### 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-market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are provided below.

Table 2.5-27 Greater Fresno Area load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Total Generation (MW) | Storage (Helms +Battery) (MW) | Solar | | Wind | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| FRESNO-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3,375 | 60 | 562 | 187 | 3,129 | 57 | 28 | 3644 | 1257 | 1442 | 361 | 13 | 4 | 2,928 | 1,253 |
| FRESNO-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3,481 | 100 | 684 | 231 | 3,150 | 58 | 28 | 3654 | 1257 | 1618 | 404 | 13 | 4 | 2,928 | 1,220 |
| FRESNO-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3,696 | 172 | 969 | 331 | 3,193 | 58 | 28 | 3688 | 1257 | 1618 | 404 | 13 | 4 | 2,928 | 1,254 |
| FRESNO-2019-SPR-LL | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 1,067 | 42 | 562 | 0 | 1,026 | 57 | 28 | 1181 | 45 | 1442 | 0 | 13 | 1 | 2,928 | 399 |
| FRESNO-2022-SPR-OPK | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 1,535 | 82 | 687 | 649 | 803 | 58 | 27 | 2553 | -865 | 1618 | 1598 | 13 | 13 | 2,928 | 1,311 |
| FRESNO-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift and AAEE sensitivity | 3,350 | 60 | 562 | 115 | 3,174 | 57 | 28 | 3642 | 1257 | 1442 | 361 | 13 | 4 | 2,928 | 1,251 |
| FRESNO-2027-SP-PS | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 3,684 | 172 | 969 | 89 | 3,423 | 58 | 28 | 3654 | 1257 | 1618 | 404 | 13 | 4 | 2,928 | 1,221 |
| FRESNO-2022-SP-HIGH CEC | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 3,481 | 0 | 687 | 89 | 3,392 | 58 | 28 | 3654 | 1257 | 1618 | 405 | 13 | 4 | 2,928 | 1,220 |
| FRESNO-2022-SP-HIGH RENEW-MINGAS | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 3,074 | 87 | 687 | 687 | 2,300 | 58 | 28 | 3987 | 1257 | 1618 | 1618 | 13 | 13 | 2,928 | 356 |
| FRESNO-2027-SP-QFRETIRE | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 3,696 | 172 | 969 | 331 | 3,312 | 58 | 28 | 3495 | 1257 | 1618 | 404 | 13 | 0 | 2,928 | 1,061 |

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3 with an exception of following approved projects that are not modeled in the base cases:

Table 2.5-28: Fresno approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Northern Fresno 115 kV Area Reinforcement | 2012-2013 TPP | Dec-2022 |
| Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor | 2010 TPP | May-2020 |
| Caruthers - Kingsburg 70 kV Line Reconductor | 2009 TPP | Apr-2019 |
| Kearney - Caruthers 70 kV Line Reconductor | 2012-2013 TPP | Apr-2019 |
| McCall - Reedley #2 115 kV Line | 2013-2014 TPP | May-2022 |
| Oro Loma - Mendota 115 kV Conversion Project | 2010-2011 TPP | May-2019 |
| Reedley 70 kV Reinforcement | 2011-2012 TPP | Feb-2020 |
| Reedley 115/70 kV Transformer No. 2 Replacement Project | 2013-2014 TPP | May-2021 |
| Reedley-Orosi 70 kV Line Reconductor | 2010 TPP | Dec-2018 |
| Reedley-Dinuba 70 kV Line Reconductor | 2010 TPP | Mar-2019 |
| Wilson 115 kV Area Reinforcement | 2010-2011 TPP | May-2019 |
| Oro Loma 70 kV Area Reinforcement | 2010-2011 TPP | Apr-2023 |
| Borden 230 kV Voltage Support | 2011-2012 TPP | May-2019 |
| Wilson Voltage Support | 2015-2016 TPP | Dec-2019 |
| Gates-Gregg 230 kV Line | 2012-2013 TPP | Dec-2022 |
| Gates No. 2 500/230 kV Transformer | 2012-2013 TPP | Dec-2022 |
| Kearney - Herndon 230kV Line Reconductor | 2012-2013 TPP | Mar-2019 |

### 2.5.6.4 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Greater Fresno Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirements were identified are discussed below.

*Herndon-Bullard #1 & # 2 115 kV Overload*

There were several Category P2 contingency overloads identified on the section of the line between Pinedale Junction and the Bullard Substation for the baseline and sensitivity scenarios. To mitigate this overload, the ISO is recommending approval of the “Herndon-Bullard # 1 & # 2 reconductoring project. The scope of this project is to reconductor six (6) circuit miles (3 miles of double circuit transmission lines) between Pinedale Junction and the Bullard Substation on the Herndon-Bullard #1 and #2 115 kV Lines.

*Coalinga 70 kV Area Overload*

There were Category P2 overloads identified on sections of the Schindler-Huron-Gates 70 kV line (Huron Junction to Cal flax substation & Schindler to five point switching station) in the spring off-peak scenario. This is due the over-generation in the area and can be mitigated by the redispatching the generation in the area.

#### *Summary of review of previously-approved projects*

There are 26 previously-approved active projects in the Greater Fresno Area, of which 17 projects were not modeled in the study cases due to either constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The nine projects modeled in the study cases were found to have current needs consistent with the scope of the projects and are recommended to move forward as is. The table below shows the recommendations for the 17 projects that were not modeled in the study cases:

Table 2.5-29: Recommendation for previously-approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Northern Fresno 115 kV Area Reinforcement | Revised Scope |
| Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor | Cancel |
| Caruthers - Kingsburg 70 kV Line Reconductor | Cancel |
| Kearney - Caruthers 70 kV Line Reconductor | Proceed |
| McCall - Reedley #2 115 kV Line | Cancel |
| Oro Loma - Mendota 115 kV Conversion Project | Cancel |
| Reedley 70 kV Reinforcement | Revised Scope |
| Reedley 115/70 kV Transformer No. 2 Replacement Project | Revised Scope[63] |
| Reedley-Orosi 70 kV Line Reconductor | Cancel |
| Reedley-Dinuba 70 kV Line Reconductor | Cancel |
| Wilson 115 kV Area Reinforcement | Revised Scope |
| Oro Loma 70 kV Area Reinforcement | Revised Scope |
| Borden 230 kV Voltage Support | Revised Scope |
| Wilson Voltage Support | Proceed |
| Gates-Gregg 230 kV Line | On Hold |
| Gates # 2 ( Bank # 12) 500/230 kV Transformer | Proceed |
| Kearney-Herndon 230 kV Line Reconductor | Proceed |

[63] The associated terminal equipment work to increase the rating of the T/F was already completed.

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high-level discussions of projects recommended to proceed with revised scope:

*Northern Fresno 115 kV Area Reinforcement*

Based on the latest analysis, the ISO determined that a substantially reduced scope to sectionalize the McCall and Herndon 230 kV buses will mitigate the overloads identified in the 2017-2018 TPP assessment. This revised scope and the appropriate operating procedures will be sufficient to mitigate the reliability needs identified in this study

Original Scope:

- Build new 230/115kV substation northeast of Fresno
- Reconductor 115kV facilities using existing right of ways ( ROWs). Sectionalize Herndon 230 kV and McCall 230 kV buses.
- 2012-2013 TPP estimated cost: $110 to 190 Million
- Current estimated cost: $300 to 381 Million

Revised Scope:

- Sectionalize Herndon 230 kV and McCall 230 kV buses and develop an operating solution for any incremental P6 overloads.
- 2017-2018 TPP estimated cost: $26 Million
- In-service Date: March 2020

*Oro Loma Area Reinforcement Projects (Oroloma-Mendota 115 kV conversion and Oroloma 70 kV reinforcement project)*

There were multiple P1, P2, P3 &P6 contingencies resulting in overloads on several 70 kV lines in baseline and sensitivity scenarios. In addition, there was only one P6 overload identified in the baseline (2019 spring light load) scenario that resulted in overload on the 70 kV line that was proposed to be converted to 115 kV as part of the Oro Loma -Mendota 115 kV Conversion Project. Based on the latest analysis, extending the summer setup mitigates the overload associated with the 70 to 115 kV conversion project. The extension of the summer setup along with reconductoring of several 70 kV lines in the area also mitigates the overloads associated with the 70 kV reinforcement project. This revised scope was found to be sufficient to mitigate the reliability needs identified in this study.

Original Scope:

- Convert approximately 20 circuit miles from Oro Loma to Mendota from 70 to 115 kV operation
- Install two SCADA switches at Firebaugh
- Replace the 70/12 kV transformer at Firebaugh with 115/12 kV transformer
- Create 115 kV terminals at Oro Loma and Mendota substations

- Build a new 230/70 kV Mercy Springs Substation looped into the Los Banos – Panoche #2 230 kV Line.
- Install one 200 MVA 230/70 kV transformer
- Install a 70 kV ring bus sectionalizing the Los Banos-Canal-Oro Loma 70 kV Line.
- Rebuild the line from Mercy Springs Junction to Canal as a double circuit tower line.
- 2012-2013 TPP estimated cost: $110 to 190 million
- Current estimated cost: $167 million

Revised Scope:

- The current revised scope to extend the summer setup beyond summer along with some 70 kV reconductors addresses the reliability need for both the Oroloma-Mendota 115 kV conversion project and the 70 kV reinforcement projects.
- 2017-2018 TPP estimated cost: $31 Million
- In-service Date: May 2024

*McCall-Reedley # 2 115 kV line Project*

There were P2 (sensitivity only) & P6 contingencies resulting in overloads on a couple of 115 kV lines in the area. This previously-approved project in the area was not modeled in the study cases due to a potential cheaper alternative solution that could resolve reliability issues as seen in the studies. Based on the latest studies and the overloads being primarily P6, operating solutions and SPS were deemed sufficient to mitigate the reliability issues observed in the latest studies. With this the McCall-Reedley #2 115 kV Line project is recommended to be canceled and PG&E is recommended to install an SPS to drop load to mitigate for the P6 contingency.

*Wilson 115 kV Area Reinforcement*

There were multiple P2 and P6 contingencies resulting in overloads and in some instance voltage issues on several 115 kV lines and buses in the baseline and sensitivity scenarios. The revised scope includes conversion of existing 115 kV bus to a breaker-and-a-half configuration, addition of a new 230/115 kV transformer and rerating a 115 kV line to mitigate the reliability issues identified in the area.

Original Scope:

- Build a new 230 /115 kV substation.
- Build a 4 mile 115 kV line to El Capitan.
- Reconfigure El Capitan Substation.
- 2010-2011 TPP estimated cost: $35 to $45 million
- Current estimated cost: $91 million

Revised Scope:

- Line relocation only by 2020 to make room for Wilson 115 kV SVC project
- Convert existing Wilson 115 kV bus to breaker-and-a-half configuration.
- Replace limiting equipment on Wilson 230/115 kV Bank #1 to obtain full bank capacity (269 MVA SN, 322.9 MVA SE)
- Install third 230 /115 kV transformer at Wilson
- Replace limiting components and rerate the Atwater-Atwater Junction 115 kV Line section
- 2017-2018 TPP estimated cost: $71 million
- In-service Date: 2023

*Borden 230 kV Area Voltage Support*

There were several Category P6 contingency driven voltage issues identified at Borden 70 and 230 kV buses in both the baseline and sensitivity scenarios. Besides the reliability need this project was also needed to ensure deliverability of generation in the ISO generation interconnection process. The proposed revised scope of the project is to proceed with only the looping of Wilson-Gregg 230 kV into Borden substation. The need for additional reactive support for this area is not seen based on the current assessment.

Original Scope:

- Loop the Wilson-Gregg 230 kV line into Borden substation.
- Install approximately 200 MVAR of reactive support on the 230 kV bus at Borden substation.
- 2011-2012 TPP estimated cost: $15 to 20 million
- Current estimated cost: $23 to 23 million

Revised Scope:

- Proceed with the loop-in of the Wilson-Gregg 230 kV line into Borden Substation. There was no additional reactive support required for the Borden 230 kV bus.
- 2017-2018 TPP estimated cost: $23 Million
- In-service Date: February 2019

*Reedley 70 kV Area Reinforcement Projects*

There are four previously-approved projects in the Reedley 70 kV system that would mitigate the overloads.

- Reedley 115/70 kV Transformer Capacity Increase (2012-2013 TPP),
- Reedley 70 kV reinforcement (2011-2012 TPP),
- Reedley Orosi 70 kV Line Reconductor (2010 TPP), and

- Reedley Dinuba 70 kV Line Reconductor (2010 TPP)

These projects were not modeled in the study cases to assess need for the projects and potential alternative solution that can mitigate the identified reliability issues due to potentially overlapping mitigation in the area of the projects. There was a Category P1 overload seen in the 2019-spring light load scenario in the area.

<u>Original Scope:</u>

<u>Reedley 115/70 kV Transformer Capacity Increase</u>

- Phase 1: Replace the limiting substation equipment to obtain the full bank rating of existing bank (90 MVA summer normal, and 108 MVA summer emergency).
- The Phase 2 project scope is to replace the four single-phase transformers comprising the Reedley 115/70 kV Transformer No. 2 with four single phase 60 MVA transformers to obtain a 180 MVA summer normal and 198 MVA summer emergency capacity. Additionally a custom rating will be requested for Reedley 115/70 kV Transformer No. 4 for summer emergency conditions (4-hour rating). Associated terminal equipment is to be upgraded as necessary to obtain the desired bank ratings.
- 2012-2013 TPP estimated cost: $12 to $18 million
- Current estimated cost: $10 to $15 million

<u>Reedley 70 kV Reinforcement</u>

- Replace limiting equipment on the Reedley-Orosi 70 kV Line #1 to get the full conductor rating of the 715.5 AAC between Reedley and Orosi Junction.
- Reconductor 9 miles of the Dinuba-Orosi 70 kV Line #1 from Dinuba to Stone Corral Junction with 715.5 AAC.
- 2010 TPP estimated cost : $7 to 10 million
- Current estimated cost: $5 to 15 million

<u>Reedley Orosi 70 kV line Reconductor</u>

- Reconductor approximately 2 miles of the Reedley-Orosi 70 kV line from Orosi Jct to Orosi Substation. In addition, 20 MVARs of shunt capacitors will be installed at Dinuba Substation.
- 2010 TPP estimated cost : $4 million
- Current estimated cost: $6 million

<u>Reedley-Dinuba 70 kV Line Reconductor</u>

- Reconductor approximately 8 miles of the Reedley Dinuba 70 kV Line
- 2010 TPP estimated cost : $8 million
- Current estimated cost: $10 million

The 2017-2018 TPP reliability assessment did not identify the need for the Reedley Transformer bank # 2 replacement after the limiting terminal equipment work was completed. The Reedley 115/70 kV Transformer Capacity Increase is recommended to be approved the revised to remove the Reedley 115/70 kV transformer replacement. The associated terminal equipment work to increase the rating of the transformer was already completed. With this the Reedley 115/70 kV Capacity Increase project is complete.

The other overload seen in the latest studies can be mitigated by extending the summer setups that were temporarily put in place in the area to mitigate the overloads; however, this option reduces the operational flexibility and the load serving capability in the area. The recommendation is to cancel the Reedley-Dinuba 70 kV Reconductor and Reedley-Orosi projects and approve the Reedley 70 kV Reinforcement project (revised scope) to use the 10 MW Energy storage at Dinuba 70 kV substation addresses the reliability needs for this area.

Revised Scope (Reedley 70 kV Reinforcement)

- Install 7 MW 4 hour Energy Storage device at Dinuba 70 kV substation
    - Energy storage to be a transmission asset.
- Upgrade Dinuba 70 kV substation to accommodate new Energy Storage
- 2017-2018 TPP estimated cost: $14 Million
- In-service Date: 2021

Gates 500/230 kV #2 Transformer

The Gates 500/230 kV #2 Transformer project was approved in the 2012-2013 TPP. The project addresses overloads identified in the Bulk System reliability assessment in section B1, provides renewable integration benefits with increased helms pumping windows and is required for deliverability of existing and proposed generation in the area. The previously-approved project is recommended to proceed with current scope and is expected to be in-service by December 2019 with a current estimated cost of $36 million.

Kearney-Herndon 230 kV Line Reconductoring

The Kearney-Herndon 230 kV Line Reconductoring project was approved in the 2012-2013 TPP. The project addresses overloads identified in the Bulk System reliability assessment in section B1, provides renewable integration benefits with increased helms pumping windows and is required for deliverability of existing and proposed generation in the area. In addition congestion was noted in the economic assessment in section 4. The previously-approved project is recommended to proceed with current scope and is expected to be in-service by March 2019 with a current estimated cost of $13 million

Gates-Gregg 230 kV Line

The Gates-Gregg 230 kV Line project was approved in the 2012-2013 TPP. The project was put on hold in the 2016-2017 TPP. The assessment determined the reliability need had been deferred by at least 10 years due to the change in load characteristics in the area allowing increased pumping from the HELMS facility to allow for generation during peak loading conditions in the area. There were renewable integration benefits due to increased pumping conditions; however these were not found to provide adequate economic benefits. The load forecast, profile and load modifier assumptions (DER) in the 2017-2018 TPP are consistent with those of the 2016-2017 TPP assessment when the ISO put the project on hold.

There still is uncertainty of the renewable integration benefits that may need further assessment for the determination of the need for the Gates-Gregg 230 kV Line project, in particular the CPUC Integrated Resource Plan (IRP) and the CEC 2017 IEPR Energy Demand Forecast. PG&E has confirmed that while the project is on hold it is continuing to accrue carrying costs since March 2017 when the 2017-2018 Transmission Plan was approved by the ISO Board of Governors. With this, If the project remains on hold and is canceled in future cycles no additional costs associated with leaving it on hold. The recommendation is for Gates-Gregg 230 kV Line project to remain on hold with detailed renewable integration assessment to be conducted in the 2018-2019 TPP to address the uncertainties and renewable integration benefits for the project

#### 2.5.6.5 *Request Window Submissions*

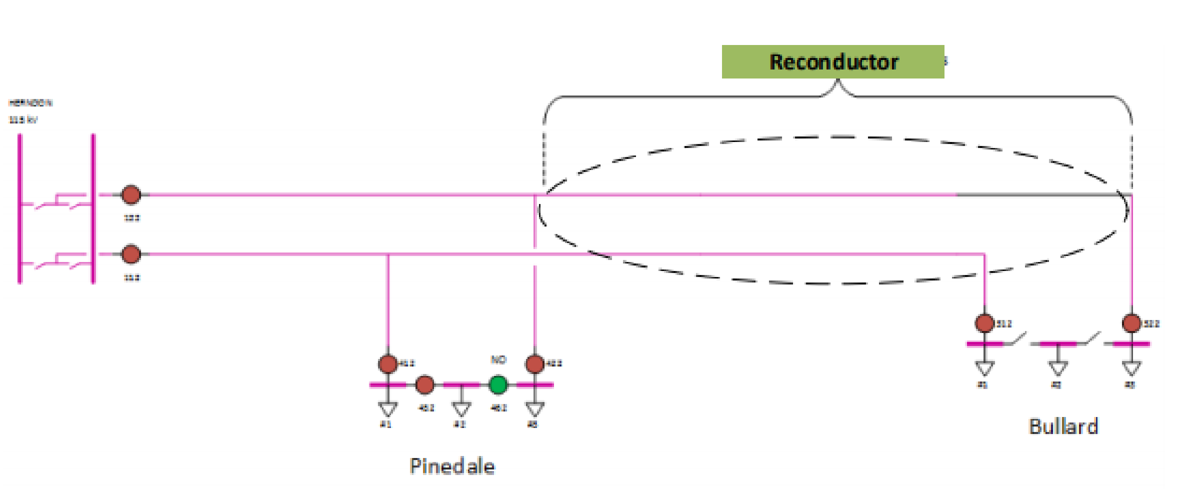
*Request Window Submission – Wellhead Merchant Transmission Line*

Wellhead Power Development, LLC (Wellhead), on behalf of Trinity Transmission LLC, submitted a merchant transmission facility (Trinity Transmission) within the PG&E service territory. Trinity Transmission was proposed to operate nominally at 70 kV and connect between the Giffen substation and the Helm substation. The project was identified by Wellhead to mitigate the congestion seen in the day ahead and real time markets. The ISO review of the project did not identify any reliability concerns with the merchant transmission facility.

*Request Window Submission – PG&E Herndon-Bullard 115 kV Reconductoring Project*

PGE submitted the reconductoring project to mitigate the P2 overloads identified on the six circuit miles (3 miles of double circuit transmission lines) between Pinedale Junction and Bullard Substation on the Herndon-Bullard #1 and #2 115kV Lines. The overloads were observed in the baseline and sensitivity scenarios. The scope is shown in the figure below:

Table 2.5-30: Herndon-Bullard 115 kV reconductoring Project




As noted above, the ISO has found the need for this reliability-driven project.

Alternatives Considered - Energy Storage

This alternative is not recommended because after evaluating the real time data and load profile, it requires a large size of energy storage on the energy base (MWh) in order to mitigate the P2-1 issue, which is likely very costly compared with recondutoring the short section of the lines.

### 2.5.6.6 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1, about 100 MW of AAEE and more than 684 MW of installed behind-the-meter PV reduced the Greater Fresno Area load in 2022 by about 9.5%. This year's reliability assessment for Greater Fresno Area included the "high CEC forecast" sensitivity case for the year 2022 which modeled no AAEE and about 231 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reductions in net load:

Table 2.5-31: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Oroloma-Elnido 115 kV line | P2 |
| Chevpipe-Santa Nla 70 kV line | P2 |
| Los Banos-Chevpipe 70 kV line | P2 |
| Borden-Madera 70 kV line | P2 |
| McCall-Sanger 115 kV line | P2 |
| Kingsburg-Contadina 115 kV line | P2 |
| GWFHEP to Contadina 115 kV line | P6 |
| Coalinga to San Miguel 70 kV line | P6 |

Furthermore, about 58 MW of demand response is modeled in Greater Fresno Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn’t completely alleviate the overloads.

#### 2.5.6.7 *Recommendation*

Based on the studies performed in the 2017-2018 transmission planning cycle, several reliability concerns were identified for the PG&E Greater Fresno Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the Greater Fresno Area.

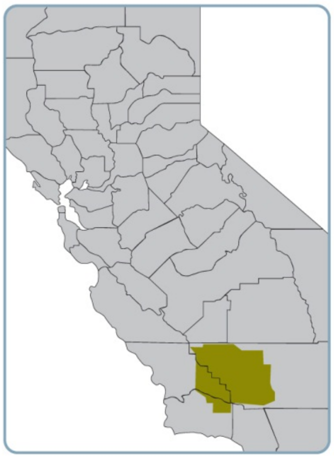
Of the two projects submitted through Request Window in the Greater Fresno Area in this cycle, the ISO recommends approval for the PG&E Herndon-Bullard 115 kV Reconductoring Project.

In regards to 17 previously-approved projects projects not modeled in the 2017-2018 base cases, no changes were identified for four projects which shall proceed with their current scopes, the ISO is recommending six projects be canceled, the scope is being revised for six projects, and one project will continue to be on hold.

### 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 the southern California Edison's (SCE) service territory. Midway substation, one of the largest substations in the PG&E system, is located in the Kern area and has 500 kV transmission connections to PG&E's Diablo Canyon, Gates and Los Banos substations as well as SCE's Vincent substation. The figure on the left depicts the geographical location of the Kern area.



The bulk of the power that interconnects at Midway substation transfers onto the 500 kV transmission system. A substantial amount also reaches neighboring transmission systems through Midway 230 kV and 115 kV transmission interconnections. These interconnections include 230 kV lines to Yosemite-Fresno in the north as well as 115 and 230 kV lines to Los Padres in the west. Electric customers in the Kern area are served primarily through the 230/115 kV transformer banks at Midway, Kern Power Plant (Kern PP) substations and local generation power plants connected to the lower voltage transmission network.

#### 2.5.7.2 *Area-Specific Assumptions and System Conditions*

The Kern Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are provided below:

Table 2.5-32 Kern Area load and generation assumptions

| Base Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar PV | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| KERN-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,948 | 30 | 255 | 85 | 1,833 | 76 | 56 | 2 | 726 | 181 | 3,247 | 2,825 |
| KERN-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 2,065 | 50 | 273 | 98 | 1,917 | 77 | 58 | 2 | 726 | 181 | 3,247 | 2,893 |
| KERN-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 2,190 | 85 | 401 | 137 | 1,967 | 77 | 58 | 2 | 726 | 181 | 3,247 | 2,696 |
| KERN-2019-SPR-LL | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 726 | 21 | 255 | 0 | 705 | 76 | 56 | 2 | 726 | 0 | 3,247 | 329 |
| KERN-2022-SPR-OPK | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 1,214 | 40 | 273 | 273 | 901 | 77 | 58 | 2 | 726 | 665 | 3,247 | 2,641 |
| KERN-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift and AAEE sensitivity | 1,939 | 30 | 255 | 52 | 1,857 | 76 | 58 | 2 | 726 | 181 | 3,247 | 2,715 |
| KERN-2027-SP-PS | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 2,290 | 85 | 401 | 37 | 2,168 | 77 | 58 | 2 | 726 | 181 | 3,247 | 2,887 |
| KERN-2022-SP-HIGH CEC | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 2,095 | 0 | 273 | 38 | 2,058 | 77 | 58 | 2 | 726 | 181 | 3,247 | 2,888 |
| KERN-2022-SP-HIGH RENEW-MINGAS | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 1,858 | 43 | 273 | 273 | 1,525 | 77 | 58 | 2 | 726 | 181 | 3,247 | 551 |
| KERN-2027-SP-QFRETIRE | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 2,189 | 85 | 401 | 137 | 1,966 | 77 | 58 | 2 | 726 | 181 | 3,247 | 2,565 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of following approved projects that are not modeled in the base cases:

Table 2.5-33: Kern approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Wheeler Ridge-Weedpatch 70 kV Line Reconductor | 2013-2014 TPP | Apr-2019 |
| Kern PP 115 kV Area Reinforcement | 2011-2012 TPP | Jun-2020 |
| Wheeler Ridge Junction Substation | 2013-2014 TPP | May-2020 |
| North East Kern Voltage Conversion Project | 2014-2015 TPP | May-2025 |
| Midway-Temblor 115 kV Line Reconductor and Voltage | 2012-2013 TPP | Apr-2019 |
| Wheeler Ridge Voltage Support | 2011-2012 TPP | Dec-2020 |

### 2.5.7.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Kern Area identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

*TAFT 70 kV Area Overloads*

NERC category P6 contingency overloads were identified on several 70 kV lines for the 2019 spring light load baseline scenario. The overloads can be mitigated by extending the summer setup in the area.

*Midway 115 kV Area Overloads*

NERC category P2 contingency overloads were seen on the Tupman # 1 & # 2 taps of the Midway-Tupman 115 kV line for both the baseline and sensitivity scenarios. ISO is proposing new summer setup that includes opening Tupman CB 142 and closing CB 136. This would help get rid of the P2 contingencies seen in the analysis. The P6 overloads will be mitigated using the congestion management.

#### *Summary of review of previously-approved projects*

There are 11 previously-approved active projects in the Kern Area, out of which six projects were not modeled in the study cases due to either constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The five projects modeled in the study cases were found to have current need consistent with the scope of the project and are recommended to move forward as is. Table below shows final recommendation for the 17 projects not modeled in the study cases:

Table 2.5-34: Recommendation for previously approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Wheeler Ridge-Weedpatch 70 kV Line Reconductor | Proceed with current scope |
| Kern PP 115 kV Area Reinforcement | Revised Scope |
| Wheeler Ridge Junction Substation | Proceed with current scope |
| North East Kern Voltage Conversion Project | Cancel |
| Midway-Temblor 115 kV Line Reconductor and Voltage | Proceed with current scope |
| Wheeler Ridge Voltage Support | Proceed with current scope |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high-level discussion of projects recommended to proceed with revised scope.

*Kern PP 115 kV Area Reinforcement (Kern PP 115 kV Reinforcement Project)*

There were multiple P0 to P7 overloads and in some instance divergence issues on several 115 kV lines in various baseline and sensitivity scenarios (including Peak shifts and the worst overloads in the QF sensitivity scenarios). To mitigate these overloads, the ISO is recommending approval of the "Kern PP 115 kV Reinforcement" (revised scope) and to rename the project to "*Kern 115 kV Reinforcement "*.

Original Scope:

- Reconductor 3.8 miles of the Kern PP-Westpark #1 115 kV line with 795 ACSS.
- Reconductor 3.8 miles of the Kern PP-Westpark #2 115 kV line with 795 ACSS.
- Reconductor 16.5 miles of the Kern-Magunden-Witco 115 kV line with 795 ACSS.
- Reconductor 3.5 miles of the Westpark-Magunden 115 kV line from Columbus to Magunden with 795 ACSS.
- Reconductor 5.0 miles of the Kern-Lamont 115 kV line from Kern PP to Tevis Jct. with 795 ACSS.

- Reconductor 5.0 miles of the Kern-Stockdale 115 kV line from Kern PP to Tevis Jct. with 795 ACSS.
- 2011-2012 TPP estimated cost: $40 to 65 million
- Current estimated cost: $50 to 64 million

<u>Revised Scope:</u>

- Rerate 9 miles of the Kern-Magunden-Witco 115 kV line (Kern Oil Junction to Magunden) with at least 805 Amp & upgrade Magunden CB122.
- Rerate Kern-Magunden-Witco 115 kV line (Kern Oil Junction to Kern Water & Kern Power to Kern Water) with at least 780 Amp.
- Reconductor 3.5 miles of the West park-Magunden 115 kV line from Columbus to Magunden with 560 Amp.
- Rerate Lerdo-Kern Oil-7th Standard 115 kV (Lerdo Junction to Kern Oil section). This was originally part of North East conversion project.
- Reconductor 6.63 miles of the Kern – Live Oak 115 kV Line with a conductor capable of at least 621 amps during summer emergency conditions. This was originally part of *North East conversion project.*
- Reconductor 4.6 miles of the Live Oak – Kern Oil 115 kV Line with a conductor capable of at least 852 amps during summer emergency conditions. This was originally part of *North East conversion project*.
- 2017-2018 TPP estimated cost: $ 24 Million
- In-service Date: December 2023

*<u>Wheeler Ridge Junction station (Casa Loma Project)</u>*

The project was put on hold in the 2016-17 transmission planning process and not modeled in the 2017-18 assessment. However, this resulted in multiple P1, P2, &P6 contingency overloads on several 230 kV line sections (Midway-Wheeler Ridge 230 kV lines) in various baseline and sensitivity scenarios. The ISO evaluated couple of alternatives that included using the existing and upgraded 115 kV infrastructure to mitigate the reliability issues. However, these options did not provide the same level of reliability services as offered by the original project. The previously-approved project is recommended to proceed with original scope and is expected to be in-service by May 2024 based on current estimates.

*Wheeler Ridge Voltage Support Project*

There were multiple low voltage issues identified under P0, P1 & P2 contingencies for several baseline and sensitivity scenarios. The previously-approved project will mitigate the reliability issues identified in the latest studies. With that, the recommendation is to proceed with the original scope of the project. The expected in-service date for the project is December 2020.

*North East Voltage Conversion Project*

There were P2 & P6 contingencies resulting in overloads on couple of 115 kV lines in the area. However with the reassessment of the Kern Area 115 kV reinforcement and Wheeler Ridge Junction Substation projects, most of the reliability constraints are addressed by these projects. The original 70 kV to 115 kV conversion was not determined to be required based on 2017-2018 TPP reliability assessment with the recommendation for the revised scope for the Kern 115 kV Area Reinforcement project and the Wheeler Ridge Junction project. The North East Voltage Conversion Project is recommended to be canceled.

### 2.5.7.4 *Request Window Submissions*

There were no request window submissions for Kern Area.

### 2.5.7.5 *Consideration of Preferred Resources and Energy Storage*

As presented in Section 2.5.1, about 30 MW of AAEE and more than 255 MW of installed behind-the-meter PV reduced the Kern Area load in 2022 by about 7%. This year's reliability assessment for Kern Area included the "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 98 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-35: Reliability Issues in Sensitivity Studies

| Facility | Category |
|---|---|
| Kern-WestPark # 1 115 kV | P3 |
| Kern-WestPark # 2 115 kV | P3 |
| Kern Oil-Live Oak 115 kV | P6 |
| LiveOak-Kern Oil 115 kV | P2 |
| Kern PP 230/115 kV # 3 | P2 |
| Kern PP 230/115 kV # 5 | P2 |
| Kern PP- Tevis J1 115 kV line section | P2 |
| Kern PP- Tevis J2 115 kV line section | P2 |
| Wheeler-Weedpatch 70 kV line | P3 |

Furthermore, about 76 MW of demand response and 2 MW of battery energy storage are modeled in Kern Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn’t completely alleviate the overloads.

#### 2.5.7.6 *Recommendation*

Based on the studies performed for the 2016-2017 Transmission Plan, several reliability concerns were identified for the PG&E Kern Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the Kern Area.

In regards to the previously-approved project, out of 6 projects not modeled in the 2017-2018 ISO TPP, three projects are recommended to proceed with current scope, one project for cancelation, two projects to proceed with revised scope.

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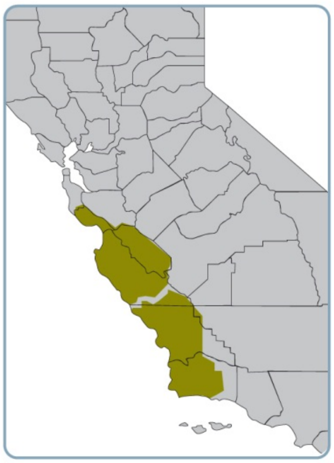
## 2.5.8 Central Coast and Los Padres Areas

### 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 green shaded portion in the figure on the left depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. It consists 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 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, also in this area, is supplied by 230 kV lines from the Moss Landing and Panoche substations, and the Burns-Point Moretti sub-area is supplied by a 60 kV line from the Monta Vista Substation in Cupertino. Besides the 60 kV transmission system interconnections between 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 2,900 MW, which includes the 2,600 MW Moss Landing Power Plant, which is scheduled for compliance with the SWRCB Policy on OTC plants by the end of 2020.

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 in this division. The city of Lompoc, a member of the Northern California Power Authority, is also located in this area. Counties in the area include San Luis Obispo and Santa Barbara. The 2400 MW Diablo Canyon Nuclear Power Plant (DCPP) is also located in Los Padres. Most of the electric power generated from DCPP is exported to the north and east of the division through 500 kV bulk transmission lines; in terms of generation contribution, it has very little impact on the Los Padres division 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. With the retirement of the Morro Bay Power Plants, the present total installed generation capacity for this area is approximately 950 MW. This includes the recently installed photovoltaic solar generation resources in the Carrizo Plains, which includes the 550 MW Topaz and 250 MW California Valley Solar Ranch facilities on the Morro Bay-Midway 230 kV line corridor. The total installed capacity does not include the 2400 MW DCPP output as it does not serve the load in the PG&E's Los Padres division.

#### 2.5.8.2 *Area-Specific Assumptions and System Conditions*

The Central Coast and Los Padres areas 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Coast and Los Padres areas study are provided below.

Table 2.5-36 Central Cost and Los Padres Area load and generation assumptions

| Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| CCLP-2019-SP | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,351 | 33 | 223 | 75 | 1,243 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2022-SP | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,395 | 55 | 273 | 94 | 1,248 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2027-SP | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,502 | 89 | 456 | 160 | 1,253 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2019-WP | Baseline | 2019 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,338 | 34 | 223 | 0 | 1,304 | 28 | 16 | 0 | 1,105 | 0 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2022-WP | Baseline | 2022 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,382 | 54 | 273 | 0 | 1,325 | 28 | 16 | 0 | 1,105 | 0 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2027-WP | Baseline | 2027 winter peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,488 | 96 | 456 | 0 | 1,392 | 28 | 16 | 0 | 1,105 | 0 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2019-ML | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 693 | 23 | 223 | 0 | 668 | 28 | 16 | 0 | 1,105 | 0 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2022-SOP | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 1,072 | 42 | 273 | 259 | 771 | 28 | 16 | 0 | 1,105 | 870 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2022-SP-PS-AAEE | Sensitivity | 2022 summer peak load conditions with peak-shift and AAEE sensitivity | 1,380 | 0 | 273 | 37 | 1,343 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2019-SP-PS | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 1,340 | 33 | 223 | 47 | 1,260 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2027-SP-PS | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 1,484 | 90 | 456 | 44 | 1,350 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2022-SP-HiRenew | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 1,304 | 47 | 273 | 273 | 984 | 28 | 16 | 0 | 1,105 | 1,105 | 0 | 0 | 0 | 0 | 249 | 162 |
| CCLP-2027-SP-QF | Sensitivity | 2027 summer peak load conditions with QF retirement sensitivity | 1,502 | 89 | 456 | 160 | 1,253 | 28 | 16 | 0 | 1,105 | 276 | 0 | 0 | 0 | 0 | 249 | 162 |

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of following approved projects which are not modeled in the base cases:

Table 2.5-37: Central Coast / Los Padres approved projects not modeled in base case

| Project Name | TPP Approved In | Current ISD |
|---|---|---|
| Watsonville Voltage Conversion Project | 2009 TPP | Jun-2021 |
| Midway-Andrew Project | 2012-2013 TPP | Jun-2025 |
| Morro Bay 230/115 kV Transformer Project | 2010 TPP | Apr-2019 |
| Diablo Canyon Voltage Support Project | 2012-2013 TPP | Dec-2019 |
| Cayucos 70 kV Shunt Capacitor Project | 2010-2011 TPP | Mar-2021 |

### 2.5.8.3 *Assessment Summary*

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 2017-2018 reliability assessment of the PG&E Central Coast and Los Padres areas have identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously-approved projects.

The areas where additional mitigation requirement were identified are discussed below.

*Coburn-Oil Fields 60 kV system*

Category P3 post contingency low voltage issues were identified in the Coburn-Oil Fields 60 kV system. With the Sargent Canyon Cogen retired, and a G-1/L-1 loss of Salinas River Cogen and one Coburn-Oil Fields 60 kV line could result in low voltage issues within the area. The identified post contingency low voltage issues can be mitigated by installing a 10 MVAR shunt capacitor at Oil Fields 60 kV substation. The Oil Fields 60 kV Voltage Support project is recommended for approval. The estimated cost of the project is $7 to 10 million with an in-service date of May 2022.

*Crazy Horse-Salanis 115 kV Lines*

Category P5, P6 and P7 contingency overloads are identified in the Salinas 115 kV system. In the 2016-2017 TPP the Natividad Substation Project was canceled. With the overloads identified in the 2017-2018 TPP reliability assessment again, the ISO will continue to assess mitigation plans that will either require upgrades identified in the Natvidad Substation project or recommending PG&E to install an SPS to mitigate the reliability constraints.

### *Summary of review of previously-approved projects*

There are six previously-approved active projects in the Central Coast/Los Padres area, out of which five projects are not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The project modeled in the study cases are found to have current need consistent with the scope of the project are recommended to move forward as is. Table below shows final recommendation for the 5 projects not modeled in the study cases:

Table 2.5-38: Recommendation for previousl approved projects not modeled in the study cases

| Project Name | Recommendation |
|---|---|
| Watsonville Voltage Conversion Project | Cancel |
| Midway-Andrew Project | Hold |
| Morro Bay 230/115 kV Transformer Project | Hold - Further review with Midway-Andrew project |
| Diablo Canyon Voltage Support Project | Hold - Further review with Midway-Andrew project |
| Cayucos 70 kV Shunt Capacitor Project | Cancel |

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below is the high level discussion of projects recommended to proceed with the revised scope:

*Watsonville Voltage Conversion Project*

The reliability assessment identified thermal overloads in the area P6 and P7 in the area. The contingencies would result in approximately 200 MW of load loss. The previously-approved Watsonville Voltage Conversion project approved in the 2010 TPP would address the reliability constraints. The Watsonville Voltage Conversion project was not modelled in the base case to assess additional alternatives due to increases in the estimated cost and potential feasibility issues identified for the implementation of the project.

Original Scope:

- Convert the 60 kV system that serves Watsonville into a 115 kV system. The new system will connect into the Green Valley 115 kV buses and the Crazy Horse 115 kV buses.
- 2009 TPP estimated cost: $25 to 30 million
- Current estimated cost: $40 to 70 million

Alternative 1: (Morgan Hill Area Reinforcement (Spring)" revised scope in Greater Bay Area.

- Rebuild Metcalf - Green Valley 115kV into the Green Valley - Morgan Hill 115kV (all new structures; 15 miles).
- Rebuild Morgan Hill 115kV into a BAAH.
- 2017-2018 TPP estimated cost: $72 to $104 million
- In-service Date: May 2021

The reliability issues in the Watsonville Morgan Hill areas are very similar. The two previously-approved projects, the Watsonville Voltage Conversion and the Morgan Hill Area Reinforcement (Spring Substation) projects each address the local area needs; however the recommended re-scoping of the Morgan Hill Area Reinforcement addresses the reliability needs in both the Watsonville and Morgan Hill area. With this the Watsonville Voltage Conversion project is recommended to be canceled.

*Midway-Andrew Project*

The reliability assessment identified severe thermal overloads in the area P2, P6 and P7 in the 115 kV system supplied from the Mesa substation. In addition the load in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area. The previously-approved Midway-Andrew 230 kV project approved in the 2012-2013 TPP would address the reliability constraints. The Midway-Andrew 230 kV project was not modelled in the base case to assess additional alternatives due to increases in the estimated cost and potential feasibility issues identified for the implementation of the project.

Original Scope:

- Build new 230/115 kV Andrew substation
- Upgrade existing Midway-Santa Maria 115 kV line to 230 kV and build new Andrew-Divide 115 kV line.
- 2012-2013 TPP estimated cost: $120 to $150 million
- Current estimated cost: $215 to $215 million
- Current in-service date: June 2025

The need for mitigation in the area is still required. The ISO is assessing potential alternatives to the project that would *repurpose* one of the 500 kV lines from Midway to Diablo after the retirement of the Diablo Nuclear Power Plants in 2025. The alternatives would convert one of the 500 kV circuits on the double circuit line to 230 kV with the 230 kV line providing a supply to an new 230/115 kV substation similar to Andrews substation in the original scope or an additional 230 kV supply to the existing Mesa substation with a new 230/115 kV transformer at Mess substation and 115 kV upgrades in the area. Additional assessment of the Bulk System requirements with Diablo generation retirements in conjunction with the conversion of one of the 500 kV circuits to 230 kV is required. The current in-service date for the Midway-Andrew 230 kV project is 2025 which would be the same for the alternatives converting one of the 500 kV circuits to 230 kV. The recommendation for the Midway-Andrew 230 kV project is to remain on hold with the further assessment to be conducted in the 2018-2019 TPP.

Morro Bay 230/115 kV Transformer Project

The reliability assessment identified thermal overloads in the area P2, P6 and P7 in the area. The previously-approved Morro Bay 230/115 kV Transformer project approved in the 2010 TPP would address the reliability constraints. The Morrow Bay 230/115 kV Transformer project was not modelled in the base case to assess additional alternatives due to increases in the estimated cost and potential feasibility issues identified for the implementation of the project.

Original Scope:

- Install a new 230/115 kV transformer at Morro Bay substation
- 2010 TPP Estimated Cost: $8 – $10 million
- Current Estimated Cost: $50 – $60 million
- Current In-service date: April 2019

The identified overloads would also be addressed by the Midway-Andrews 230 kV project. Mitigation is still required in the area; however with the recommendation for the Midway-Andrews 230 kV project to remain on hold for further assessment in the 2018-2019 TPP as indicated above the Morro Bay 230/115 kV Transformer project is also recommended to be on hold to be assessed with the Midway-Andrews 230 kV project alternative assessment.

Diablo Canyon Voltage Support Project

The Diablo Canyon Voltage Support project was approved in the 2012-2013 transmission planning process to addres low voltage in the Diablo and Mess 230 kV system and the Messa 115 kV system. With the reassessment of the Midway-Andrew project recommending for the project to remain on hold, the ISO is also recommending for the Diablo Canyou Voltage Support project remain on hold too. The location and size for the voltage support will be reassessed with the Midway-Andrew 230 kV project in the 2018-2019 transmission planning process.

Original Scope:

- 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)
- 2012-2013 TPP Estimated Cost: $35 – $45 million
- Current Estimated Cost: $33 million
- Current In-service date: December 2019

#### 2.5.8.4 *Request Window Submissions*

Request Window Submission - *Coburn-Oil Fields 60 kV system*

Pacific Gas and Electric (PGAE) is proposing a project within Coburn-Oil Fields 60 kV system.

Category P3 post contingency low voltage issues were identified in the Coburn-Oil Fields 60 kV system. With the Sargent Canyon Cogen retired, and a G-1/L-1 loss of Salinas River Cogen and one Coburn-Oil Fields 60 kV line could result in low voltage issues within the area. The identified post contingency low voltage issues can be mitigated by installing a 10 MVAR shunt capacitor at Oil Fields 60 kV substation. The Oil Fields 60 kV Voltage Support project is recommended for approval. The estimated cost of the project is $7 to 10 million with an in-service date of May 2022.

*Request Window Submission* - Lopez to Divide 500/230 kV Transmission System

NextEra Energy Resources, LLC is proposing a project Lopez to Divide 500/230 kV Transmission system.

NextEra Energy Resources, LLC is proposing Lopez-Divide project to mitigate for Category P6, P7, P5 and P2 contingencies. The project scope is to build a new Lopez 500 kV ring bus to loop into Diablo-Midway #3 500 Kv line. Install a new 230 kV substation Lopez and a new 230 kV Divide bus. Construct a new 24 mile line from Lopez substation to Divide substation. Install Lopez 500/230 kV and Divide 230/115 kV Transformers.

The project is addressing the post contingency thermal and voltage collapse issues for P5, P6 and P7. For Category P2 Contingencies “Divide-Ma and Divide Cabrillo #1”, this project could not mitigate the post contingency thermal overloads. Also, for P2 Contingency “Mesa 115 kV section 2D &1D”, this project needs additional modification to the existing Mesa/Santa Maria RAS to mitigate for the post contingency thermal overloads. Also, it does not go over any practicality issues like zoning and other local permissions to construct the new lines.

This project would address similar reliability issues to the previously-approved Midway-Andrew 230 kV project that is recommended to remain on hold.

#### 2.5.8.5 *Recommendation*

Based on the studies performed for the 2017-2018 Transmission Plan, several reliability concerns were identified for the PG&E Central Coast and Los Padres Areas. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously-approved projects within the Central Coast and Los Padres Areas.

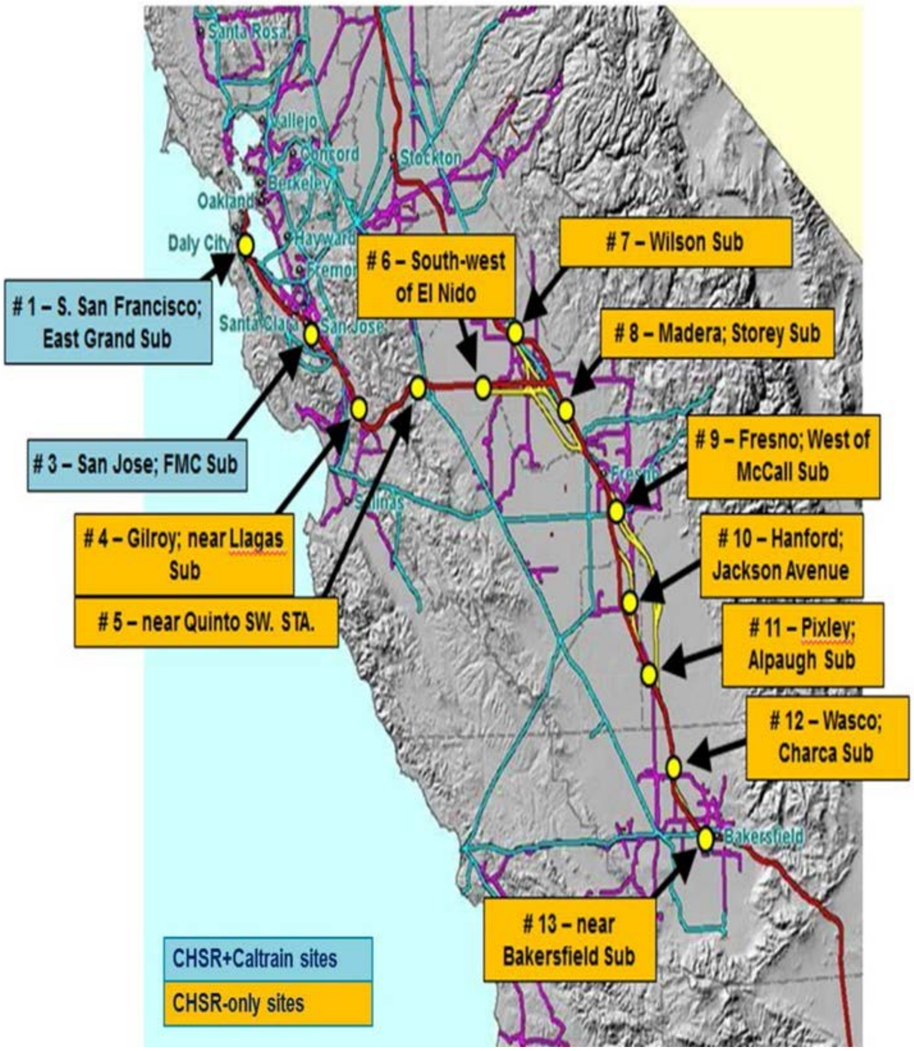
Out of the two projects submitted through Request Window in the CCLP Areas in this cycle, the ISO recommends approval for the Coburn-Oil Fields 60 kV system project. The Lopez-Divide project is mitigating the Category P5,P6 and P7 contingencies but it is not mitigating the P2 contingencies. Also, Lopez-Divide project needs to go through the public hearing process to better understand the local zoning and other permissions to construct the new line and new equipment. For the remaining areas (Natividad Substation) identified for additional mitigation requirement, the ISO will continue to work towards identifying the best mitigation solution including reconductoring the sections where we are observing the post contingency thermal overloads. The ISO will continue to work with PG&E to develop action plans in the interim.

In regards to the previously-approved projects, out of 5 projects not modeled in the study cases, Cayucos 70 kV Shunt Capacitor Project and Watsonville project are recommended to be canceled. The reliability issues identified in the Watsonville area are mitigated by the revised scope of the Morgan Hill Area Reinforcement project in Greater Bay Area. The Midway-Andrew project is recommended to remain on hold with the further assessment to be conducted in the 2018-2019 TPP. The Morro Bay 230/115 kV Transformer Project and the Diablo Canyon Voltage Support Project are also recommended to be on hold to be assessed with the Midway-Andrews 230 kV project alternative assessment.

## 2.5.9 California High Speed Train Project Load Interconnection

In the 2017 Request Window PG&E submitted the load interconnections at ten locations on the transmission system for the California High Speed Train Project (CHSTP). Figure 2.5-1 shows the location of the load interconnections. The load interconnections at Sites 1 and 3 were previously studied together with the Caltrain Electrification Project in San Francisco and South San Francisco.

Table 2.5-39: CHSTP load interconnection locations




The load forecast from the California High Speed Train Project when PG&E conducted the interconnection studies was considerably higher than current projections with a total load of 361 MVA. Table 2.5-40 provides the current California High Speed Train Project load forecast for each of the locations of the load interconnections and the forecast loads at each of the interconnections. The current load forecast, within the planning horizon is considerably lower than the original forecast. The California High Speed Rail Authority will provide updated load forecasts annually to PG&E for the 10 year planning horizons. The forecasts will be incorporated in the annual transmission planning process.

Table 2.5-40: CHSTP Load Forecast

| Site | Location | CHSTP Load Forecast (MVA) | | | |
|---|---|---|---|---|---|
| | | Maximum 2021 load MVA | Maximum 2023 load MVA | Maximum 2028 load MVA | Maximum 2029-2087 load MVA |
| 4 | Gilroy, near Llagas Substation | 3 | 5 | 16 | 22 |
| 5 | Near Quinto Switching Station | 1 | 2 | 6 | 8 |
| 6 | South-west of El Nido | 1 | 2 | 5 | 7 |
| 7 | Wilson Substatin | 2 | 4 | 7 | 14 |
| 8 | Madera, Storey Substation | 1 | 3 | 6 | 12 |
| 9 | Fresno West of McCall Substation | 3 | 7 | 13 | 27 |
| 10 | Hanford, Jackson Avenue | 3 | 6 | 11 | 22 |
| 11 | Pixley, Alpaugh Substation | 0 | 1 | 2 | 3 |
| 12 | Wasco, Charca Substation | 1 | 1 | 2 | 4 |
| 13 | Near Bakersfield Substation | 3 | 6 | 13 | 26 |
| | Total | 18 | 36 | 81 | 144 |

Table 2.5-41 identifies the project scope and estimated costs (interconnection and network upgrades) at each interconnection site based upon PG&E's presentation at the ISO's September 2017 stakeholder meeting[64]. The network upgrades identified for mitigation were assessed at the original load forecast from the California High Speed Rail Authority. With the reduced load, particularly within the planning horizon, some of the network upgrades for mitigation may be deferred.

[64]http://www.caiso.com/Documents/Day2_PG_E-Presentation_2017-2018TransmissionPlanningProcess_PreliminaryReliabilityResults.pdf

Table 2.5-41: Interconnection and network upgrade description and estimated costs

| Site | Interconnection Project Scope | Estimated Cost Interconnection facility $M | Estimated Cost Network Upgrade (Interconnection) $M | Estimated Cost Network Upgrade (Mitigation) $M | In-Service Date |
|---|---|---|---|---|---|
| 4 | • Construct a new Switching Station with a 2-Bay Breaker-and-a-half (BAAH) configuration to loop in Spring –Llagas115 kV Line.<br>• Extend 115 kV double-line from the new switching station to CHSR site 4.<br>• Substation work at Llagas substation | $8 | $52 | $40 | 2020 |
| 5 | • Expand existing Quinto Switching Station with four (4) new circuit breakers to complete one partial bay and build a new partial bay.<br>• •Build ~0.9 circuit mile of 230 kV double-line extension from CHSR Site 5 to Quinto SW STA<br>• •Raise Tesla –Los Banos and Tracy Los Banos500 kV Lines for the two CHSR lines to pass underneath. | $14 | $23 | $2 | 2020 |
| 6 | • Rebuild El Nido Substation with 3-bay BAAH configuration.<br>• •Build ~6 circuit mile of double circuit 115kV T-line extensions from CHSR Site 6 to El Nido Substation. | $21 | $46 | $25 | 2020 |
| 7 | • Expand Wilson substation 230 kV bus to 4-Bay BAAH configuration and re-arrange existing lines and loads.<br>• •Build ~2.4 circuit mile of double circuit 115 kV T-Line extension from Wilson substation to CHSR Site 7. | $15 | $39 | $0 | 2020 |
| 8 | • Rebuild Storey Substation into a 4-Bay BAAH configuration.<br>• •Loop both Wilson-Borden No.1 and No.2 230 kV Lines into Storey Substation.<br>• •Construct double-circuit 230 kV T-line extension from Storey Substation to CHSR Site 8 | $8 | $66 | $21 | 2020 |
| 9 | • Construct a new 230 kV 2-Bay BAAH Switching Station on Cedar Avenue.<br>• •Loop Gates –McCall 230 kV Line (currently Mustang SW STA -McCall 230 | $8 | $37 | $0 | 2020 |

| Site | Interconnection Project Scope | Estimated Cost Interconnection facility<br>$M | Estimated Cost Network Upgrade (Interconnection)<br>$M | Estimated Cost Network Upgrade<br>(Mitigation)<br>$M | In-Service Date |
|---|---|---|---|---|---|
| | kV Line) into the new switching station for CHSR Site 9.<br>• •Construct double-circuit 230 kV T-line extension from the new Cedar Ave. SW STA to CHSR Site 9. | | | | |
| 10 | • Construct a new 115 kV 4-bay BAAH Switching Station (SW STA) named Jackson SW STA.<br>• •Connect eight (8) 115 kV transmission lines into Jackson SW STA. Three (3) from Kingsburg, one (1) from Corcoran, one(1) from Waukena SW STA, one (1) from GWF Hanford SW STA and two (2) reserved for CHSR Site 10.<br>• •Construct double-circuit 115 kV T-line extension from Jackson SW STA to CHSR Site 10. | $4 | $78 | $51 | 2020 |
| 11 | • Rebuid Alpaugh Substation into 3-Bay BAAH configuration<br>• •Construct double -circuit 115 kV T-lines from Alpaugh Substation to CHSR Site 11 | $4 | $62 | $0 | 2020 |
| 12 | • Construct a new 115kV 2-bay BAAH switching station.<br>• •Loop Semitropic-Charca115kV transmission line into the new switching station.<br>• •Build ~0.5 circuit mile of double circuit 115kV T-line extensions from CHSR Site 12 to the new switching station. | $4 | $38 | $28 | 2020 |
| 13 | • Construct a new 230kV 2-bay BAAH switching station ~0.2 mile from Bakersfield 230 kV Substation on strip of land to the West.<br>• •Loop Kern PP -Bakersfield 230 kV line into the new switching station.<br>• •Construct ~0.5 mile double-circuit 230kV T-line extension from the new switching station to CHSR Site 13.<br>• •Implement Ground Grid coordination between the new 230 kV switching station and Bakersfield 230 kV Substation. | $3 | $42 | $0 | 2020 |

| Site | Interconnection Project Scope | Estimated Cost Interconnection facility $M | Estimated Cost Network Upgrade (Interconnection) $M | Estimated Cost Network Upgrade (Mitigation) $M | In-Service Date |
|---|---|---|---|---|---|
| | • •Substation work at Bakersfield and the new switching station. | | | | |
| | Total | $89 | $483 | $165 | |
| | | $737 | | | |

Load interconnections are facilitated under PG&E's tariff. PG&E has indicated that the treatment of cost allocation under the tariff is will be based on the general principles of cost responsibility including, but not limited to, the following:

- Facilities that are requested by, or are necessary to serve, a customer and which only benefit that customer should have such costs, including all applicable labor, materials, or other necessary costs, borne solely by that customer until such time as other utility customers benefit from those facilities.
- Should a customer have specific service requirements that exceed the customary or most economical means to serve the customers' expected load, that customer shall bear all costs for facilities, including all applicable labor, materials, or other necessary costs, in excess of those that would otherwise be required to provide the customary or most economical service.

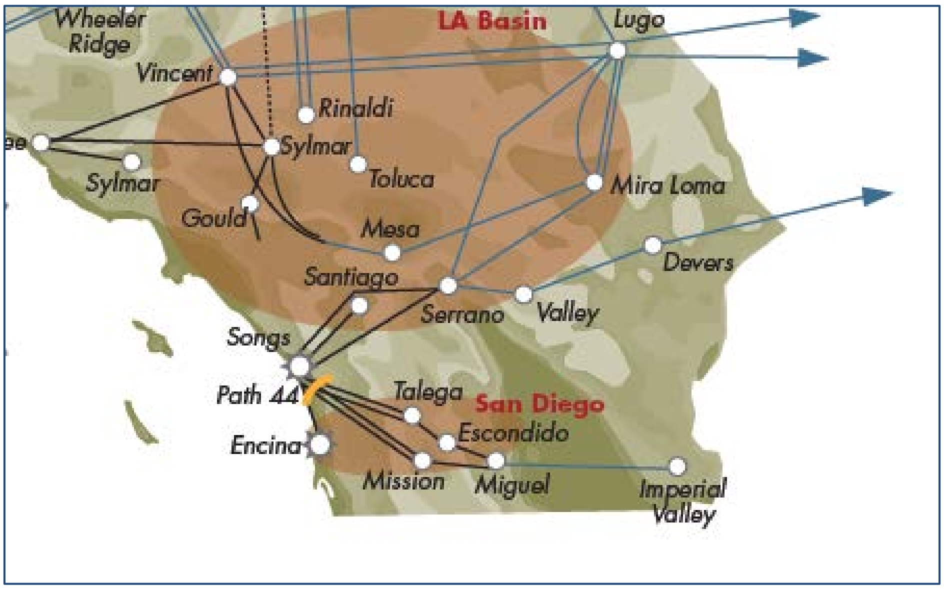
The ISO has reviewed the load interconnection submitted into the 2017 Request Window in the 2017-2018 transmission planning process. The review considered the review of previously-approved projects in the PG&E area. With the change to the Morgan Hill Area Reinforcement project, the interconnection location for Site 4 will need to be changed from Spring-Llagas 115 kV line to Morgan Hill-Llagas 115 kV line. The assessment of the revised scope Morgan Hill Area Reinforcement considered the addition of the load interconnect identified for Site 4. The ISO concurs with the proposed interconnections by PG&E, with the noted change, to interconnect the California High Speed Rail Authority load at the requested locations as a part of the California High-Speed Rail Project.

## 2.6 Southern California Bulk Transmission System Assessment

### 2.6.1 Area Description

The southern California bulk transmission system primarily includes the 500 kV transmission systems of Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) companies and the major interconnections with Pacific Gas and Electric (PG&E), LA Department of Water and Power (LADWP) and Arizona Public Service (APS). Figure 3 provides an illustration of the southern California's bulk transmission system.

Table 2.6-1: Southern California Bulk Transmission System




SCE serves about 15 million people in a 50,000 square mile area of central, coastal and southern California, excluding the City of Los Angeles[65] and certain other cities[66]. Most of the SCE load is located within the Los Angeles Basin. The CEC's load growth forecast for the SCE Transmission Access Charge (TAC) area is about 33.4 MW[67] on the average per year; however, after considering the projection for mid additional achievable energy efficiency (AAEE), the demand forecast is declining at an average rate of 182.7 MW per year[68]. The CEC's 1-in-5 load forecast for the SCE TAC Area includes the SCE service area, and the Anaheim Public Utilities, City of Vernon Light & Power Department, Pasadena Water and Power Department, Riverside Public Utilities, California Department of Water Resources and Metropolitan Water District of southern California pump loads. The 2027 summer peak 1-in-5 forecast load, including system losses, is

[65] The City of Los Angeles' power need is served by the Los Angeles Department of Water and Power.

[66] Cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside and Vernon have electric utilities to serve their own loads. The City of Cerritos Electric Department serves city-owned facilities, public and private schools and major retail customers.

[67] Based on the CEC-adopted California Energy Demand Forecast 2016-2027 (Form 1.5c) – Mid Demand Baseline Case, No AAEE Savings, February 2017 version

[68] Based on the CEC-adopted California Energy Demand Forecast 2016-2027 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE Savings, February 2017 version

21,470 MW[69]. The SCE area peak load is served by generation that includes a diverse mix of renewables, qualifying facilities, hydro and gas-fired power plants, as well as by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and the Desert Southwest.

SDG&E provides service to 3.4 million consumers through 1.4 million electric meters in San Diego and southern Orange counties. Its service area encompasses 4,100 square miles from southern Orange County to the U.S. and Mexico border. The existing points of imports are the South of SONGS[70] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2027 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE and system losses is 4,238 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, small pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 4,062 MW of OTC-related electric generation has been retired since 2010. In the next three years, the remaining existing 6,698 MW of gas-fired generation is scheduled to retire to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos, Huntington Beach and Encina generation, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with the CPUC's assigned commissioner's ruling addressing assumptions for the 2014 LTPP and 2016-2017 transmission plan[71] (the 2016-2017 LTPP/TPP A&S document), the ISO has also taken into account the potential retirement of 2,194 MW of aging non-OTC and mothballed generation in the area.[72]

To offset the retirement of SONGS and OTC generation, the CPUC in the 2012 LTPP Track 1 and Track 4 decisions authorized SCE to procure between 1900 and 2500 MW of local capacity in the LA Basin area and up to 290 MW in the Moorpark area, and SDG&E to procure between 800 and 1100 MW in the San Diego area.[73] In May 2015, the CPUC issued Decision D.15-05-051 that conditionally approved SDG&E's application for entering into a purchase power and tolling agreement (PPTA) with Carlsbad Energy Center, LLC, for 500 MW. The Decision also required the residual 100 MW of requested capacity to consist of preferred resources or energy

[69] Based on the CEC-adopted California Energy Demand Forecast 2016-2026 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE Savings, February 2017 version

[70] The SONGS was officially retired on June 7, 2013.

[71] Rulemaking 13-12-010 "Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long-Term Procurement Plan and 2015-2016 CAISO TPP" on March 4, 2015, with minor updates issued in October, 2015.

[72] Includes generating units that are more than forty years of age, as well as units that have been mothballed by the owners.

[73] The CPUC Decisions D.13-02-015 (Track 1 for SCE), D.14-03-004 (Track 4 for SCE), D.13-03-029/D.14-02-016 (Track 1 for SDG&E), and D.14-03-004 (Track 4 for SDG&E).

storage. In November 2015, the CPUC issued Decision D.15-11-041 to approve, in part, results of SCE's Local Capacity Requirements Request for Offers for the Western LA Basin. The Decision permitted SCE to enter into a PPTA for a total of 1812.6 MW of local capacity that includes 124.04 MW of energy efficiency, 5 MW of demand response, 37.92 MW of behind-the-meter solar photovoltaic generation, 263.64 MW of energy storage, and 1382 MW of conventional (gas-fired) generation. In this analysis, the ISO considered the authorized levels of procurement and then focused on the results thus far in the utility procurement process – which, in certain cases, is less than the authorized procurement levels.

As set out below, preferred resources and storage are expected to play an important role in addressing the area's needs. As the term "preferred resources" encompasses a range of measures with different characteristics, they have been considered differently. Demand side resources such as energy efficiency programs are accounted for as adjustments to loads, and supply side resources such as demand response are considered as separate mitigations. Further, there is a higher degree of uncertainty as to the quantity, location and characteristics of these preferred resources, given the unprecedented levels being sought and the expectation that increased funding over time will result in somewhat diminishing returns. While the ISO's analysis focused primarily on the basic assumptions set out below in section 2.6.2, the ISO has conducted and will continue to conduct additional studies as needed on different resources mixes submitted by the utilities in the course of their procurement processes.

### 2.6.2 Area-Specific Assumptions and System Conditions

The southern California bulk transmission system steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers and generation dispatch assumptions for the various scenarios used for the southern California bulk transmission system assessment are provided below.

Table 2.6-2 Southern California bulk transmission load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Fast (MW) | Slow (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| B1 | 2019 Summer Peak | Base | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 28,929 | 822 | 3,267 | 1229 | 26,878 | 504 | 494 | 161 | 7425 | 2813 | 4922 | 198 | 1447 | 232 | 22,169 | 12,458 |
| B2 | 2022 Summer Peak | Base | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 29,535 | 1515 | 4,272 | 1586 | 26,434 | 509 | 494 | 451 | 9643 | 3581 | 5022 | 231 | 1447 | 1173 | 18,378 | 11,043 |
| B3 | 2027 Summer Peak | Base | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 30,631 | 2717 | 6,859 | 2534 | 25,380 | 509 | 494 | 451 | 9643 | 3581 | 5022 | 231 | 1447 | 1058 | 18,378 | 11,328 |
| B4 | 2019 Spring Light Load | Base | 2019 spring light load conditions. Light load time - hours between 02:00 and 6:00. | 8,981 | 254 | 3,267 | 0 | 8,727 | 504 | 494 | 161 | 7425 | 0 | 5022 | 4563 | 1447 | 382 | 22,169 | 1,241 |
| B5 | 2022 Spring Off-Peak | Base | 2022 spring off-peak load conditions. Off-peak load time – weekend morning | 19,553 | 939 | 4,272 | 1,868 | 17,775 | 509 | 494 | 451 | 9643 | 8106 | 5022 | 4535 | 1447 | 731 | 18,378 | 4,685 |
| B6 | 2022SP Heavy Renewables & Min Gas Gen | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 29,535 | 1515 | 4,272 | 1586 | 26,434 | 509 | 494 | 451 | 9643 | 8729 | 5022 | 2008 | 1447 | 969 | 18,378 | 8,083 |
| B7 | Off-Peak with Maximum BTM PV Output | Sensitivity | 2022 Spring Light Load with increased BTM PV | 12,362 | 1081 | 6,859 | 4856 | 6,425 | 509 | 494 | 451 | 9643 | 6135 | 5022 | 336 | 1447 | 296 | 18,378 | 2,819 |

### Transmission Assumptions

All previously-approved transmission projects were modeled in the southern California bulk transmission system assessment in accordance with the general assumptions described in section 2.3.

### Path Flow Assumptions

Table 2.6-2 lists the transfers modeled on major paths in the southern California assessment.

Table 2.6-2: Path Flow Assumptions

| Path | SOL/Transfer Capability (MW) | 2019SP (MW) | 2022SP (MW) | 2027SP (MW) | 2019 LL (MW) | 2022 OP (MW) | 2022 SP Heavy Ren. (MW) | 2022 OP Max. BTM PV (MW) |
|---|---|---|---|---|---|---|---|---|
| Path 26 (N-S) | 4,000 | 3,865 | 3,923 | 1,544 | 418 | -1,769 | 2,875 | -2,189 |
| PDCI (N-S) | 3,220 | 3,220 | 3,220 | 3,220 | 464 | 2,000 | 3,220 | 0 |
| SCIT | 17,870 | 17,573 | 15,163 | 14,069 | 4,867 | 3,705 | 12,075 | -82 |
| Path 46 (WOR)(E-W) | 11,200 | 7,839 | 6,273 | 6,863 | 3,082 | 1,061 | 4,233 | -632 |
| Path 49 (EOR)(E-W) | 10,100 | 4,755 | 3,532 | 4,042 | 1,554 | -1,000 | 1,339 | -2,192 |

## 2.6.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix C.

<u>Lugo-Victorville 500 kV thermal overload</u>

The Lugo-Victorville 500 kV line was overloaded under several Category P6 conditions in the 2019 summer peak case. The loading concern can be addressed in the operations horizon without relying on non-consequential load loss by such operational measures as re-dispatching resources and bypassing LADWP series capacitors after the initial contingency in accordance with existing operating procedures. The overload did not occur in the 2022 and 2027 cases due to the previously-approved Lugo-Victorville 500 kV Transmission Line Upgrade Project.

The southern California bulk system assessment did not identify reliability concerns that require corrective action plans to meet TPL 001-4 requirements.

### 2.6.4 Request Window Project Submissions

The applicable local area sections below detail the the request window submittals the ISO received in the current planning cycle and the results of the ISO evaluation.

### 2.6.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the southern California bulk transmission system assessment as follows.

- As indicated earlier, projected amounts of up to 2,717 MW of additional energy efficiency (AAEE), and up to 6,859 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 17 percent.
- The existing and planned fast-response demand response amounting 509 MW and energy storage amounting 451 MW were used to mitigate Category P6 related thermal overloads on Lugo-Victorville 500 kV line until the approved rating increase project is in service.
- Since no reliability issues that require mitigation were identified, incremental preferred resources and storage were not considered in the southern California bulk transmission system assessment.

### 2.6.6 Recommendation

The southern California bulk system assessment did not identify reliability concerns that require new corrective action plans to meet TPL 001-4 requirements. Loading concerns associated with the Lugo-Victorville 500 kV line will be addressed in the short term using existing operating procedures. In the longer term, the previously-approved Lugo-Victorville 500 kV Transmission Line Upgrade Project will address the loading concern.

## 2.7 SCE Local Areas Assessment

### 2.7.1 SCE Tehachapi and Big Creek Area

#### 2.7.1.1 *Area Description*

The Tehachapi and Big Creek Corridor consists of the SCE transmission system north of Vincent substation. 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 230 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

The Tehachapi and Big Creek Corridor area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 3870 MW in 2027 including the impact of 841 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 268 MW of additional achievable energy efficiency (AAEE).

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

- San Joaquin Cross Valley Loop Transmission Project (completed);
- Tehachapi Renewable Transmission Project (completed);
- East Kern Wind Resource Area 66 kV Reconfiguration Project (completed); and
- Big Creek Corridor Rating Increase Project (in-service date: 2018).

#### 2.7.1.2 *Area-Specific Assumptions and System Conditions*

The SCE Tehachapi and Big Creek Corridor Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the Tehachapi and Big Creek Corridor area study are provided below.Study Scenarios

The SCE Tehachapi and Big Creek Corridor area study included five base and six sensitivity scenarios as described below.

Table 2.7-1 Tehachapi and Big Creek Areas load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Fast (MW) | Slow (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| B1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 4,142 | 79 | 423 | 227 | 3,837 | 88 | 42 | 0 | 2,894 | 945 | 3,539 | 0 | 1,170 | 604 | 4,415 | 1,510 |
| B2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 4,278 | 151 | 527 | 287 | 3,839 | 97 | 43 | 1 | 2,905 | 945 | 3,539 | 0 | 1,170 | 604 | 4,695 | 1,759 |
| B3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 4,579 | 268 | 841 | 444 | 3,868 | 97 | 43 | 1 | 2,905 | 956 | 3,539 | 0 | 1,170 | 652 | 4,695 | 1,686 |
| B4 | 2019 Spring Light Load | Baseline | 2019 Spring light load time - hours between 02:00 and 6:00. | 956 | 19 | 423 | 0 | 937 | 88 | 42 | 0 | 2,894 | 0 | 3,539 | 3,085 | 1,170 | 396 | 4,415 | 0 |
| B5 | 2022 Spring Off-Peak | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 2,673 | 92 | 527 | 241 | 2,340 | 97 | 43 | 1 | 2,905 | 2,419 | 3,539 | 3,085 | 1,170 | 562 | 4,695 | 157 |
| S1 | 2019SP CEC Peak Shift | Sensitivity | 2019 SP with peak-shift adjustment | 4,053 | 79 | 423 | 138 | 3,836 | 88 | 42 | 0 | 2,894 | 945 | 3,539 | 0 | 1,170 | 604 | 4,415 | 1,514 |
| S2 | 2022SP High CEC Load & | Sensitivity | 2022 SP with peak-shift and high CEC load | 4,248 | 151 | 527 | 116 | 3,981 | 97 | 43 | 1 | 2,905 | 945 | 3,539 | 0 | 1,170 | 639 | 4,695 | 1,720 |
| S3 | 2022SP Heavy Renewables & Min Gas Gen | Sensitivity | 2022 SP with high renewable minimal gas generation output | 4,278 | 151 | 527 | 287 | 3,839 | 97 | 43 | 1 | 2,905 | 2,624 | 3,539 | 1,416 | 1,170 | 604 | 4,695 | 795 |
| S4 | 2022SP Low Big Creek H | Sensitivity | 2022SP with extremely low Big Creek hydro | 4,278 | 151 | 527 | 287 | 3,839 | 97 | 43 | 1 | 2,905 | 945 | 3,539 | 0 | 1,170 | 345 | 4,695 | 1,726 |
| S5 | 2027SP CEC Peak Shift | Sensitivity | 2027 SP with peak-shift adjustment | 4,299 | 268 | 841 | 150 | 3,881 | 97 | 43 | 1 | 2,905 | 956 | 3,539 | 0 | 1,170 | 652 | 4,695 | 1,686 |
| S6 | 2022 Spring Off-Peak with Maximum BTM PV Output | Sensitivity | 2022 spring off-peak with increased BTM PV | 2,468 | 57 | 1,241 | 972 | 1,439 | 97 | 43 | 1 | 2,905 | 1,470 | 3,539 | 305 | 1,170 | 204 | 4,695 | 695 |

**Demand-Side Assumptions**The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table above provides the demand-side assumptions used in the Tehachapi and Big Creek Corridor area assessment including the impact of BTM PV and AAEE. The load values include distribution system losses. The summer light load and spring off-peak cases assume approximately 30 percent and 60 percent of the net peak load, respectively.

**Supply-Side Assumptions**

The table above provides a summary of the supply-side assumptions modeled in the Tehachapi and Big Creek Corridor Area assessment including conventional and renewable generation, demand response and energy storage. A detailed list of existing generation in the area is included in Appendix A.

The ISO worked with SCE to establish low Big Creek hydro study assumptions for base case and sensitivity scenarios:

- Summer Peak base cases: The existing Big Creek / San Joaquin Valley Remedial Action Scheme triggers load drop at Rector and/or Liberty substations to mitigate overloads due to any one of the south of Rector 220 kV line N-1 contingencies. For the summer peak base cases, the ISO evaluated the minimum required Big Creek area generation to mitigate any N-1 overloads on the existing system, without having to arm load dropping.
- 2022 Summer Peak low hydro sensitivity case: The S4 sensitivity scenario models an extreme low hydro generation level. The ISO analyzed the real time Big Creek generation data from summer 2015 to evaluate the period of lowest hydro generation. Based on that, the ISO modeled total generation of 330 MW in the Big Creek area.

**Transmission Assumptions**

All previously-approved transmission projects were modeled in the Tehachapi and Big Creek Corridor Area assessment in accordance with the general assumptions described in section 2.3.

### 2.7.1.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Tehachapi and Big Creek Corridor area steady state assessment identified several Category P6 related thermal overloads under contingency conditions. The identified issues can be mitigated in the operations horizon without relying on non-consequential load loss, by such operational measures as reconfiguring the system or re-dispatching resources after the initial or second contingency as discussed in Appendix B. The stability analysis performed in the Tehachapi and Big Creek Corridor Area base case assessment did not identify transient issues that require mitigation. A stressed case was created from B5 2022 Spring Off-Peak by maximizing the Big Creek hydro generation. Stability analysis performed on this case identified local area instabilities caused by Big Creek 3-Rector No.2 230 kV and Big Creek 4-Springville 230 kV P6 contingency. The ISO is working with SCE to add the above P6 scenario in the existing Big Creek RAS to run back generation after the first contingency in high hydro scenarios to mitigate stability issues.

As a result, system additions and upgrades are not identified for the Tehachapi and Big Creek Corridor area.

#### 2.7.1.4 *Request Window Project Submissions*

The ISO did not receive request window submissions for the SCE Tehachapi and Big Creek Corridor Area in this planning cycle.

#### 2.7.1.5 *Consideration of Preferred Resources and Energy Storage*

Preferred resources and storage were considered in the SCE Tehachapi and Big Creek Corridor Area assessment as follows.

- As indicated earlier, projected amounts of up to 260 MW additional energy efficiency (AAEE), and up to 840 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 15 percent.
- The Tehachapi and Big Creek Corridor Area assessment did not identify a need for additional preferred and storage resources in the area.

#### 2.7.1.6 *Recommendation*

The SCE Tehachapi and Big Creek Corridor area assessment identified several category P6 related thermal overloads. Operating solutions including dispatching existing and planned preferred resources and energy storage under contingency conditions are recommended to address these issues.

## 2.7.2 North of Lugo Area

### 2.7.2.1 *Area Description*

The North of Lugo (NOL) transmission system serves San Bernardino, Kern, Inyo and Mono counties. The figure below depicts the geographic location of the north of Lugo area, which extends more than 270 miles.


The North of Lugo electric transmission system is comprised of 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has inter-ties with Los Angeles Department of Water and Power (LADWP) and Sierra Pacific Power. In the south, it connects to the Eldorado Substation through the Ivanpah-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah Substation through the Lugo-Pisgah Nos. 1&2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The NOL area can be divided into the following sub-areas: north of Control; Kramer/North of Kramer/Cool Water; and Victor specifically.

### 2.7.2.2 *Assumptions and System Conditions*

The North of Lugo area steady state and transient stability assessment was performed consistently with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the North of Lugo area study are provided below.

Table 2.7-2 North of Lugo Area load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| 1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 978 | 14 | 156 | 64 | 900 | 83.21 | 82.44 | 0 | 372 | 223 | 0 | 0 | 74 | 21 | 1,746 | 1,299 |
| 2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,002 | 29 | 211 | 78 | 894 | 83.21 | 82.44 | 0 | 372 | 223 | 0 | 0 | 74 | 21 | 1,746 | 1,299 |
| 3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 1,056 | 55 | 316 | 117 | 884 | 83.21 | 82.44 | 0 | 372 | 223 | 0 | 0 | 74 | 21 | 1,746 | 1,276 |
| 4 | 2019 Spring Light Load | Baseline | 2019 spring minimum load conditions. Hours between 02:00 and 06:00 with high wind and no solar output. | 272 | 4 | 156 | 0 | 268 | 83.21 | 82.44 | 0 | 372 | 0 | 0 | 0 | 74 | 21 | 1,746 | 1,299 |
| 5 | 2022 Spring Off-peak | Baseline | 2022 spring shoulder load day with maximum wind and solar output - weekend morning. | 625 | 18 | 211 | 65 | 541 | 83.21 | 82.44 | 0 | 372 | 223 | 0 | 0 | 74 | 21 | 1,746 | 1,299 |
| 6 | 2022SP Heavy Renewable & Min Gas Gen | Sensitivity | 2022 summer peak with heavy renewable output and minimum gas generation commitment | 739 | 22 | 211 | 78 | 639 | 83.21 | 82.44 | 0 | 372 | 346 | 0 | 0 | 74 | 18 | 1,746 | 1,423 |

All previously-approved transmission projects were modeled in the North of Lugo area assessment in accordance with the general assumptions described in section 2.3. The following previously-approved transmission upgrades are modeled in the 2019, 2022 and 2027 study cases:

- Victor Loop-in Project: Loop in the existing Kramer-Lugo Nos. 1&2 230 kV lines into Victor Substation.

- Kramer Reactor Project: Install two 23 Mvar reactors to the 12 kV tertiary winding of the existing 230/115 kV Nos. 1&2 transformers and one 45var shunt reactor at the Kramer 230 kV bus.

#### 2.7.2.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The 2017-2018 reliability assessment of the North of Lugo area has identified several thermal overloads issues under Category P1, P6 and P7 contingencies. It has identified one low voltage issue under Category P2 contingency. All of those issues can be mitigated in the operation horizon by relying upon the 2 hour emergency rating, utilizing congestion management or adjusting voltage schedules after the initial contingency. Appendix B has a detailed discussion.

The transient stability assessment identified a few voltage recovery and voltage dip violations under Category P4.2 and P6. The ISO recommends installing a Local Breaker Failure Backup (LBFB) scheme at certain substations and to rely on an existing operating procedure.

#### 2.7.2.4 *Request Window Project Submissions*

The ISO did not receive request window submissions for the North of Lugo area in this planning cycle.

#### 2.7.2.5 *Consideration of Preferred Resources and Energy Storage*

Preferred resources and storage were considered in the North of Lugo area assessment as follows.

- Projected amounts of up to 55 MW additional achievable energy efficiency (AAEE), and up to 117 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 16 percent.
- The existing and planned fast-response demand response amounting to 82 MW was identified and available in the base and sensitivity cases, but did not need to be activated to address any local transmission concerns in this analysis.
- The NOL Area assessment did not identify a need for additional preferred and storage resources in the area.

### 2.7.2.6 *Recommendation*

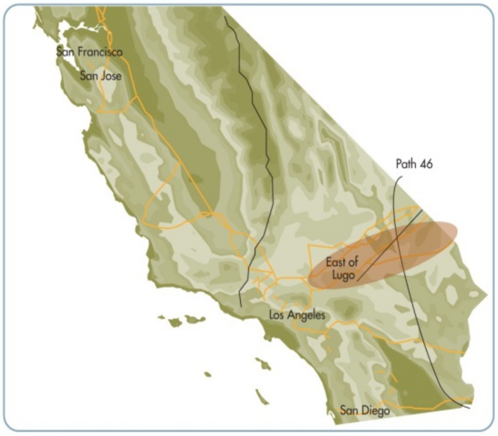
The North of Lugo area assessment identified several category P1, P6 and P7 related thermal overloads, and one category P2 related low voltage issues. Operating solutions, including relying upon a 2-hour emergency rating, congestion management and adjusting voltage schedules, are recommended to address the issues.

The assessment also identified several transient voltage recovery and voltage dip violations for category P4.2 and P6 outages. The ISO recommends installing a Local Breaker Failure Backup (LBFB) relay or utilizing an existing operating procedure.

## 2.7.3 SCE East of Lugo Area

### 2.7.3.1 *Area Description*

The East of Lugo (EOL) area consists of the transmission system between the Lugo and Eldorado substations. The EOL area is a major transmission corridor connecting California with Nevada and Arizona; is 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 jointly owned Eldorado 230 kV substation. Merchant substation was formerly in the NV Energy balancing authority, but after a system reconfiguration in 2012, it became part of the ISO system. The Harry Allen-Eldorado 500 kV line was approved by the ISO Board of Governors in 2014, is expected to be operational in 2020, and will be part of the EOL system.




The existing EOL 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;
- 115 kV transmission line from Cool Water to Ivanpah; and
- 500 kV and 230 kV tie lines with neighboring systems.

### 2.7.3.2 *Area-Specific Assumptions and System Conditions*

The East of Lugo area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the East of Lugo area study are provided below.

Table 2.7-3 East of Lugo Area load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| 1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3.62 | 0 | 0 | 0 | 3.62 | 1.71 | 0.00 | 0 | 1,254 | 451 | 0 | 0 | 0 | 0 | 525 | 417 |
| 2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 3.92 | 0 | 0 | 0 | 3.92 | 1.71 | 0.00 | 0 | 1,514 | 545 | 0 | 0 | 0 | 0 | 525 | 417 |
| 3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 4.46 | 0 | 0 | 0 | 4.46 | 1.71 | 0.00 | 0 | 1,514 | 545 | 0 | 0 | 0 | 0 | 525 | 417 |
| 4 | 2019 Spring Light Load | Baseline | 2019 spring minimum load conditions. Hours between 02:00 and 06:00 with high wind and no solar output. | 1.08 | 0 | 0 | 0 | 1.08 | 1.71 | 0.00 | 0 | 1,254 | 0 | 0 | 0 | 0 | 0 | 525 | 417 |
| 5 | 2022 Spring Off-peak | Baseline | 2022 spring shoulder load day with maximum wind and solar output - weekend morning. | 2.36 | 0 | 0 | 0 | 2.36 | 1.71 | 0.00 | 0 | 1,514 | 1,407 | 0 | 0 | 0 | 0 | 525 | 417 |
| 6 | 2022SP Heavy Renewable & Min Gas Gen | Sensitivity | 2022 summer peak with heavy renewable output and minimum gas generation commitment | 3.92 | 0 | 0 | 0 | 3.92 | 1.71 | 0.00 | 0 | 1,514 | 1,407 | 0 | 0 | 0 | 0 | 525 | 417 |

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3. There are no transmission upgrades modeled in the 2019 study cases. The transmission upgrades modeled in the 2022 and 2027 study cases are:

- Eldorado-Lugo 500 kV series capacitor and terminal equipment upgrade
- Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade
- New Calcite 230 kV Substation and loop into Lugo-Pisgah #1 230 kV line
- Lugo-Victorville 500 kV terminal equipment upgrade and remove ground clearance limitations
- Harry Allen-Eldorado 500 kV line

### 2.7.3.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE East of Lugo area steady state assessment identified several Category P6 related thermal overloads in the off-peak and sensitivity cases. Two potential system divergence issues were identified for Category P5.5 outages (bus fault plus relay failure to operate). Thermal overload issues were also identified and can be mitigated by the existing RAS and previously-approved transmission projects. The potential mitigation solution for the system divergence issues is to install a redundant relay. The stability analysis performed in the EOL Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the East of Lugo area.

### 2.7.3.4 *Request Window Project Submissions*

The ISO did not receive request window submissions for the SCE East of Lugo area in this planning cycle.

### 2.7.3.5 *Consideration of Preferred Resources and Energy Storage*

The SCE East of Lugo area is comprised of high voltage transmission lines and generation facilities with limited customer load, so the assessment did not identify a need for preferred resources and energy storage in the area.

### 2.7.3.6 *Recommendation*

The SCE East of Lugo area assessment identified several Category P6 related thermal overloads. The issues can be mitigated by the existing RAS and previously-approved transmission projects. The assessment also identified two potential system divergence issues for Category P5.5 outages, and to mitigate these issues installing a redundant bus relay is recommended.

### 2.7.4 SCE Eastern Area

#### 2.7.4.1 *Area Description*

The ISO controlled grid in the SCE Eastern Area serves the portion of Riverside County around Devers Substation. The figure below depicts the geographic location of the area. The system is composed of 500 kV, 230 kV and 161 kV transmission facilities from Vista Substation to Devers Substation and continues on to Palo Verde Substation in Arizona. The area has ties to Salt River Project (SRP), the Imperial Irrigation District (IID), Metropolitan Water District (MWD), and the Western Area Lower Colorado control area (WALC).


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

- Path 42 Upgrade Project (2016);
- West of Devers Upgrade Project (2021), and
- Delaney-Colorado River 500 kV line Project (2020).

#### 2.7.4.2 *Area-Specific Assumptions and System Conditions*

The SCE Eastern Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The load values include distribution system losses. The summer light load and spring off-peak cases assume approximately 30 percent and 60 percent of the net peak load respectively. Specific assumptions related to study scenarios, load, resources and transmission that were applied to the Eastern area study are provided below.

Table 2.7-4 Eastern Area load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| B1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 5,435 | 62 | 233 | 233 | 5,140 | 0 | 0 | 0 | 1,664 | 495 | 835 | 0 | 0 | 0 | 4,980 | 2,761 |
| B2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 5,628 | 126 | 301 | 301 | 5,202 | 0 | 0 | 0 | 3,015 | 1,048 | 835 | 0 | 0 | 0 | 4,980 | 3,630 |
| B3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 5,848 | 231 | 471 | 471 | 5,146 | 0 | 0 | 0 | 3,015 | 1,048 | 835 | 0 | 0 | 0 | 4,980 | 3,547 |
| B4 | 2019 Spring Light Load | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 04:00. | 1,499 | 17 | 233 | 0 | 1,482 | 0 | 0 | 0 | 1,664 | 0 | 835 | 776 | 0 | 0 | 4,980 | 7 |
| B5 | 2022 Spring Off-Peak | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning. | 3,400 | 74 | 253 | 253 | 3,073 | 0 | 0 | 0 | 3,015 | 2,707 | 835 | 776 | 0 | 0 | 4,980 | 1,008 |
| S4 | 2022SP Heavy Renewables & Min Gas Gen | Sensitivity | 2022 summer peak load conditions with hi renewable dispatch sensitivity | 5,628 | 126 | 301 | 301 | 5,202 | 0 | 0 | 0 | 3,015 | 1,048 | 835 | 0 | 0 | 0 | 4,980 | 3,630 |

**Transmission Assumptions**

All previously-approved transmission projects were modeled in the Eastern Area assessment in accordance with the general assumptions described in section 2.3.

#### 2.7.4.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Eastern area steady state assessment identified several Category P6 contingency related thermal overloads. The issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as reconfiguring the system after the initial or second contingency as discussed in Appendix B. The stability analysis performed in the Eastern Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the Eastern area.

#### 2.7.4.4 *Request Window Project Submissions*

The ISO received a number of request window submissions for the SCE Eastern Area in this planning cycle. Below is a description of each proposal followed by ISO comments and findings.

*Red Bluff-Mira Loma 500 kV Transmission Project*

The project was submitted by NextEra Energy Transmission West LLC and involves construction of a new 139-mile 500 kV transmission line between Red Bluff 500 kV substation and Mira Loma 500 kV substation. The project has an estimated cost of $850 million and expected in-service date of December 1, 2024.

The need for this project was assessed as part of the 2016-17 ISO transmission planning cycle and was not found to be needed. The project has also not been found to be needed in this planning cycle. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after tripping generators by the Colorado River Corridor Special Protection Scheme.

*Colorado River 230 kV Bus-Julian Hinds 230 kV*

The project was submitted by AltaGas Services and involves converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It creates a networked facility identified as Colorado River - Julian Hinds 230 kV line, and a revised 230 kV gen-tie line identified as Buck Blvd - Colorado River 230 kV line. The Colorado River - Julian Hinds 230 kV line would have 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) in series with the line. These Power Guardians will be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads. The project has an estimated cost of $62 million and expected in-service date of June 1, 2020.

The need for a similar project was assessed as part of the 2014-15 and 2016-17 ISO transmission planning cycle and was not found to be needed. The project with the inclusion of the Smart Wires devices has also not been found to be needed for reliability purposes in this planning cycle. However, power flow analysis was performed on the project to determine if it should be further considered as an economic-driven project. It was found that with the project modeled in the S4 Heavy Renewables sensitivity case, with the Smart Wires devices on the Colorado River - Julian Hinds 230 kV line fully activated, the Julian Hinds - Mirage 230 kV line was heavily overloaded under contingency conditions.

#### 2.7.4.5 *Consideration of Preferred Resources and Energy Storage*

No additional grid-connectedpreferred resources or storage was modeled in the SCE Eastern Area, and the assessment did not identify a need for additional preferred and storage resources in the area.

#### 2.7.4.6 *Recommendation*

The SCE Eastern area assessment identified several category P6 related thermal overloads. Operating solutions including dispatching existing and planned preferred resources under contingency conditions are recommended to address the issues.

## 2.7.5 SCE Metro Area

### 2.7.5.1 *Area Description*

The SCE Metro area consists of 500 kV and 230 kV facilities that serve major metropolitan areas in the Los Angeles, Orange, Ventura counties and surrounding areas. The points of interconnections with the external system include Vincent, Mira Loma, Rancho Vista and Valley 500 kV Substations and Sylmar, San Onofre and Pardee 230 kV Substations. The bulk of SCE load as well as most southern California coastal generation is located in the SCE Metro area.


The Metro area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 16,185 MW in 2027 including the impact of 3,383 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 1,347 MW of additional achievable energy efficiency (AAEE).

The area currently has approximately 10,400 MW of grid-connected generation of which a total of 5,764 MW of once-through-cooled (OTC) generation is scheduled to be retired by the end of 2020. The California Public Utilities Commission (CPUC) has approved a total of 2,086 MW of conventional generation and preferred resources for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the OTC generating plants. The retirement of the Mandalay Generating Station and Ormond Beach Generating Station - to comply with state policy regarding once-through cooling equirements - along with the potential retirement of the Ellwood Power Station will result in an unmet local capacity need in the Moorpark and Santa Clara sub-areas. Further, the CEC suspended proceedings related to NRG's application for the 262 MW Puente Power Project at NRG's request subsequent to the CEC announcing its intention to issue a proposed decision recommending denial of NRG's application, which was part of the procurement approved by the CPUC. .

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

- Mesa 500 kV Loop-In Project (12/31/2020);
- Orange Country Dynamic Reactive Support (12/31/2017);
- Laguna Bell Corridor Upgrade (12/31/2020);
- Method of Service for Alberhill 500/115 kV Substation (6/1/2021); and
- Method of Service for Wildlife 230/66 kV Substation (6/1/2021).

### 2.7.5.2 *Area-Specific Assumptions and System Conditions*

The SCE Metro Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for the various scenarios used for the SCE Metro Area assessment are provided in Table 2.7.5-1 below.

Table 2.7-5: Metro Area load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Fast (MW) | Slow (MW) | Storage (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| 1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 17,961 | 371 | 1,414 | 531 | 17,059 | 231 | 352 | 63 | 20 | 0 | 0 | 0 | 10 | 0 | 10,379 | 4,656 |
| 2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 18,228 | 723 | 1,948 | 723 | 16,781 | 236 | 352 | 327 | 383 | 122 | 0 | 0 | 10 | 0 | 6,569 | 4,009 |
| 3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00. | 18,784 | 1347 | 3,383 | 1252 | 16,185 | 236 | 352 | 327 | 383 | 122 | 0 | 0 | 10 | 0 | 6,569 | 3,717 |
| 4 | 2019 Spring Light Load | Baseline | 2019 spring light load conditions. Light load time - hours between 02:00 and 6:00. | 5,051 | 107 | 1,414 | 0 | 4,944 | 231 | 352 | 63 | 20 | 0 | 0 | 0 | 10 | 0 | 10,379 | 246 |
| 5 | 2022 Spring Off-Peak | Baseline | 2022 spring off-peak load conditions. Off-peak load time – weekend morning | 10,911 | 425 | 1,948 | 608 | 9,877 | 236 | 352 | 327 | 383 | 0 | 0 | 0 | 10 | 0 | 6,569 | 578 |
| S1 | 2019SP CEC Peak Shift | Sensitivity | 2019 summer peak load conditions with peak-shift sensitivity | 17,961 | 371 | 1,414 | 323 | 17,267 | 231 | 352 | 63 | 20 | 0 | 0 | 0 | 10 | 0 | 10,379 | 4,656 |
| S2 | 2022SP High CEC Load & Peak Shift | Sensitivity | 2022 summer peak load conditions with peak-shift and high CEC load | 18,775 | 723 | 1,948 | 292 | 17,760 | 236 | 352 | 327 | 383 | 122 | 0 | 0 | 10 | 0 | 6,569 | 4,009 |
| S3 | 2022SP Heavy Renewables & Min Gas Gen | Sensitivity | 2022 summer peak load conditions with high renewable dispatch sensitivity | 18,228 | 723 | 1,948 | 723 | 16,782 | 236 | 352 | 327 | 383 | 316 | 0 | 0 | 10 | 0 | 6,569 | 3,460 |
| S4 | 2027SP CEC Peak Shift | Sensitivity | 2027 summer peak load conditions with peak-shift sensitivity | 18,784 | 1347 | 3,383 | 423 | 17,014 | 236 | 352 | 327 | 383 | 122 | 0 | 0 | 10 | 0 | 6,569 | 3,717 |
| S5 | Summer Off-Peak with Maximum BTM PV Output | Sensitivity | 2022 Spring off-peak hour with minimum net load due to high BTM PV | 7,119 | 693 | 2,824 | 2349 | 4,077 | 236 | 352 | 327 | 383 | 14 | 0 | 0 | 10 | 2 | 6,569 | 341 |

**Transmission Assumptions**

All previously-approved transmission projects were modeled in the Metro Area assessment in accordance with the general assumptions described in section 2.3.

### 2.7.5.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Metro area steady state assessment identified several Category P6 related thermal overloads under various contingency conditions. The issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as reconfiguring the system or re-dispatching resources after the initial or second contingency as discussed in Appendix B. The stability analysis performed in the Metro Area assessment did not identify transient stability issues that require mitigation.

As a result, new corrective action plans were not found to be needed for the Metro area to meet TPL 001-4 requirements.

**Local capacity deficiency in the Moorpark and Santa Clara Sub-Areas[74]**

With the expected retirements of several gas-fired generating units to meet OTC regulations, for economic reasons, or due to age, the Moorpark and Santa Clara local capacity sub-areas are expected have a local capacity deficiency in the post 2020 period as shown in Table 2.8-6. The most critical contingency for the Moorpark sub-area is the loss of the Moorpark-Pardee 230 kV #3 line followed by the loss of the Moorpark-Pardee 230 kV #1 and #2 lines, which could cause voltage collapse. For the Santa Clara sub-area, the critical contingency is the Pardee-Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which could cause voltage collapse.

[74] This review is taking place in light of the CEC's announced intention to issue a proposed decision that recommends denial of NRG's application for the Puente Power Project and its subsequent decision to suspend the proceedings in response to NRG's request.

Table 2.7-6: Local Capacity Deficiency in the Moorpark and Santa Clara Sub-areas

| | Moorpark Sub-area | Santa Clara Sub-area |
|---|---|---|
| 2022 LCR[75] | 554 MW | 289 MW |
| Resources available post 2020[76] | 236 MW | 203 MW |
| - Existing generation | 2336 MW | 808 MW |
| - Expected retirements[77] | (2076) MW | (560) MW |
| - Ellwood assumed unavailable[78] | (54) MW | (54) MW |
| - Existing/approved preferred resources and storage | 30 MW | 9 MW |
| Deficiency[79] | ~318 MW | ~86 MW |

In addition, SCE has identified a 105 MW resiliency target in the Santa Barbara/Goleta area associated with the loss of both Goleta-Santa Clara 230 kV transmission lines.[80] New resources procured to address the Santa Barbara/Goleta resiliency objective will address Moorpark and Santa Clara LCR needs.

#### 2.7.5.4 *Request Window Project Submissions*

The ISO received one request window submittal in the SCE Metro Area in this planning cycle. Below is a description of the proposal followed by ISO comments.

*Moorpark-Pardee 230 kV No. 4 Circuit Project*

The project is submitted by SCE to address the projected local capacity deficiency in the Moorpark sub-area. It involves stringing a fourth Moorpark-Pardee 230 kV circuit approximately 26 miles on existing structures and installing terminal equipment at Moorpark and Pardee Substations. The project has an estimated cost of $45 million and an in-service date of December 31, 2020, which coincides with the retirement of OTC generation in the area. SCE anticipates the project will not be subject to a Certificate of Public Convenience and Necessity (CPCN).

75 http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf

76 Amount does not include the 10 MW energy storage project SCE submitted to the CPUC for approval in Application 17-12-002.

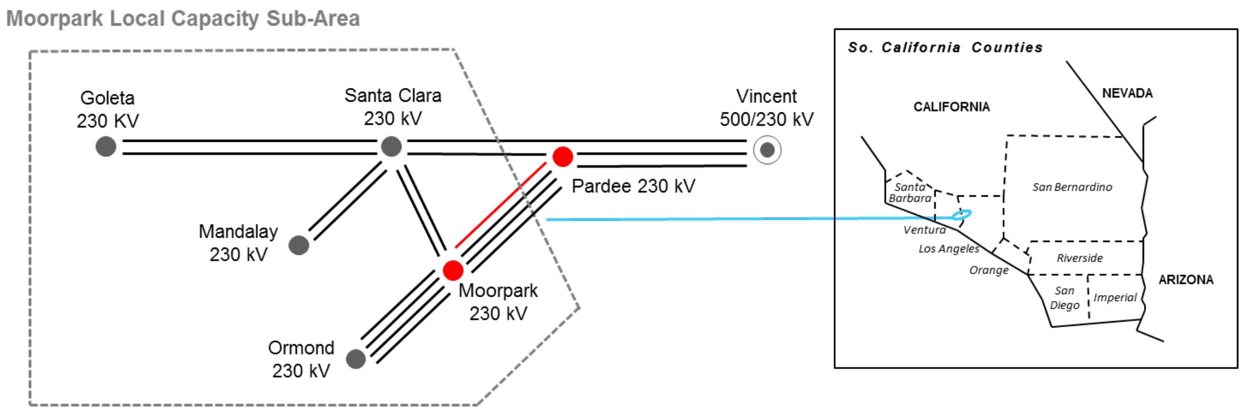
77 Ormond Beach units 1 and 2 and Mandalay units 1 and 2 are expected to retire by December 31, 2020 to comply with OTC regulations. NRG announced that all three Mandalay units would be retired on December 31, 2017, and that retirement was deferred to February 6, 2018.

78 SCE's contract with NRG to refurbish the Ellwood generating station, which is 43 year old, was denied by the CPUC.

79 Deficiency amounts are approximate as they are dependent on the location, reactive power capability and other characteristics of the resources that are used to fill the deficiency and are subject to change in the future due to changes in the CEC load forecast.

80 Moorpark Sub-Area Local Capacity Requirements Procurement Plan of Southern California Edison Company Submitted to Energy Division Pursuant to D. 13-02-015

Figure 2.7-1: Moorpark-Pardee Project Area




The Moorpark-Pardee project fully addresses the Moorpark local capacity need but does not address the 86 MW Santa Clara local capacity need or SCE's resiliency objective for the Santa Barbara/Goleta area. The ISO considered the following alternatives that can fully address the local capacity needs taking into account SCE's Goleta resiliency objectives. It is expected that new capacity will be met primarily with some combination of preferred resources, energy storage and renewables such as solar PV.

- Alternative 1 – Moorpark-Pardee project to address Moorpark LCR need coupled with 86 to 105 MW (NQC) of local capacity located downstream of Goleta to address the Santa Clara LCR needs and SCE's Goleta resiliency objectives.
- Alternative 2 – Approximately 318 MW (NQC) of local capacity to address Moorpark LCR need of which 105 MW is located downstream of Goleta to address Santa Clara LCR needs and SCE's Goleta resiliency objectives.
- Alternative 3 – 240 Mvar reactive power support coupled with 135 MW (NQC) of local capacity to address Moorpark LCR needs of which 105 MW is located downstream of Goleta to address Santa Clara LCR needs and SCE's Goleta resiliency objectives.

Figure 2.8-2 shows P-V analysis plots for the critical contingency for the status quo system and each of the alternatives. A high level comparison of the alternatives based on technical, capital cost and timing considerations is presented in Table 2.8-7[81]

[81] Due to run-time limitation of resources such as demand response and energy storage, diurnal variability of solar PV and charging requirements of energy storage, an hour by hour analysis is needed to confirm such a resource mix meets the LCR criteria in addition to the peak hour, NQC-based analysis performed in the current assessment. The ISO Moorpark Sub-Area Local Capacity Alternative Study (http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf) provides such analysis and examples of validated resource scenarios for the Moorpark sub-area.

Figure 2.7-2: Moorpark Sub-area P-V Analysis for the Critical Contingency

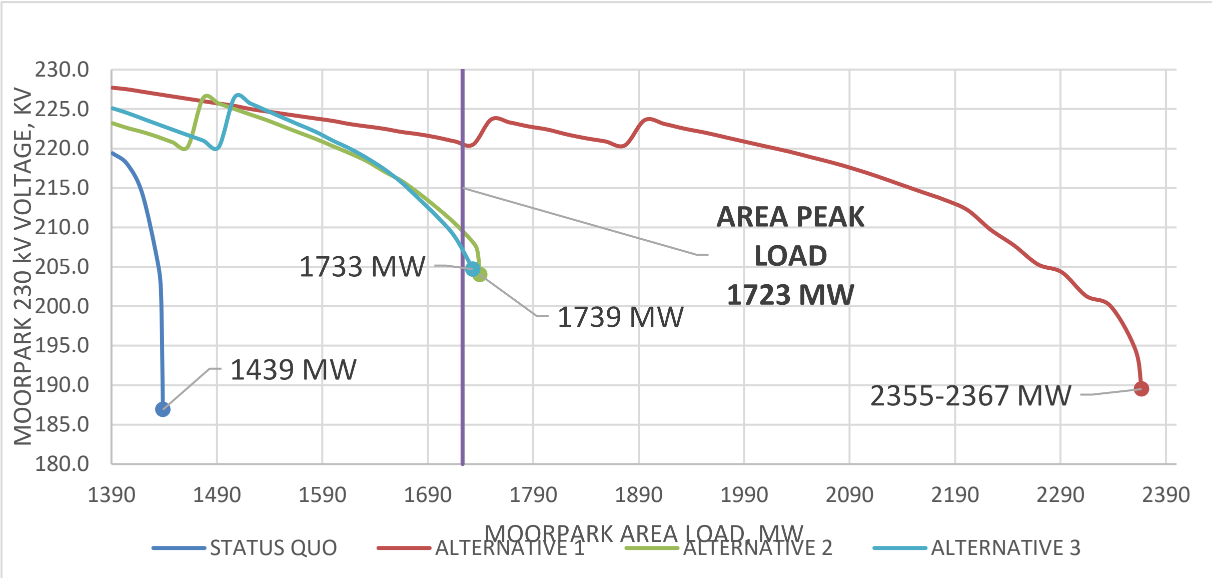



Table 2.7-7: Comparison of Alternatives

| | Alternative 1 | Alternative 2 | Alternative 3 |
|---|---|---|---|
| Increase in post contingency voltage stability area load limit | 916-928 MW | 300 MW | 294 MW |
| Max. thermal loading under critical contingency | <100% | 159% (Pardee-Santa Clara 230 kV) | 189% (Pardee-Santa Clara 230 kV) |
| Grid resiliency in the event of loss of the Pardee Substation or loss of all transmission lines in the same corridor | Neutral | Better | Neutral |
| Operational complexity due to variability, run-time limitation and charging needs of local capacity resources | Lower | Higher | Lower |
| Capital cost | Lower | Much higher[82] | Higher |
| Required 12/31/2020 in-service date | Transmission: achievable; 86 MW local capacity: agressive | Most aggressive | More aggressive |

[82] In its written comments to the January 11, 2018 TPP stakeholder call, SCE indicated that, based on its procurement experience, the 232 MW difference (318 MW minus 86 MW) between Alternatives 1 and 2 has an estimated net cost range of $850 million to $1 billion. SCE further indicated that it has considered the benefits (in dollars) of the preferred resources (e.g., energy value, capacity value, etc.) in its calculation of the estimated cost range.

The Moorpark-Pardee project was found to be needed as it results in the most effective alternative to address the voltage stability as well as the thermal loading impacts of the Moorpark sub-area critical contingency while having the least capital and overall cost and lower impact on operational complexity.

The ISO has categorized the Moorpark-Pardee project as a reliability-driven project, as it is part of basket of mitigations in a local capacity area necessary to provide the level of reliability dictated by the NERC standards, the ISO Planning Standards, and the local capacity technical criteria set out in the ISO tariff. As the reliability need could otherwise be served by acquiring additional new resources – alternative 2 described above – the transmission project could also have been categorized as "economic-driven" due to the economic comparison made in selecting the transmission project as part of the comprehensive solution.[83] Rather than unnecessarily bifurcating the discussion of the local area needs between chapter 2 dealing with reliability issues and chapter 4 dealing with economic-driven issues, the local area needs have been addressed comprehensively here in chapter 2.

#### 2.7.5.5 *Consideration of Preferred Resources and Energy Storage*

Preferred resources and storage were considered in the SCE Metro Area assessment as follows.

- As indicated earlier, projected amounts of up to 1,347 MW of additional energy efficiency (AAEE), and up to 3,383 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 14 percent.
- The existing and planned fast-response demand response amounting 236 MW and energy storage amounting 352 MW were used in the base or sensitivity cases to mitigate Category P6 related thermal overloads on Serrano 500/230 kV transformers and the Mesa-Laguna Bell No.1 230 kV line.
- Incremental preferred and renewable resources and energy storage are considered in conjunction with the Moorpark-Pardee transmission project to address local capacity needs in the Moorpark sub-area.

#### 2.7.5.6 *Recommendation*

The Moorpark-Pardee 230 kV No. 4 Circuit Project was submitted by SCE to address the projected local capacity deficiency in the Moorpark local capacity sub-area. The project has an estimated cost of $45 million and involves stringing a new Moorpark-Pardee 230 kV circuit on existing structures and installing terminal equipment at Moorpark and Pardee Substations. The project was reviewed in light of the expected retirement of more than 2000 MW generation in the area and the suspension of proceedings for the Puente Power Project. The project was found to be needed and is recommended for ISO approval as it is the most effective and economic

[83] Section 24.4.6.7 of the ISO tariff, that states: *"…the CAISO will conduct the High Priority Economic Planning Studies selected under Section 24.3.4 and any other studies that the CAISO concludes are necessary to determine whether additional transmission solutions are necessary to address: …(b) Local Capacity Area Resource requirements;"*

alternative in addressing the voltage stability and thermal loading impacts of the critical Moorpark sub-area contingency. The required in-service date is December 31, 2020 to coincide with the retirement of OTC generation in the area.

The SCE Metro area assessment also identified several category P6 related thermal overloads. Operating solutions, which are described in more detail in Appendix B, including dispatching existing and planned preferred resources and energy storage under contingency conditions are recommended to address those issues.

## 2.8 Valley Electric Association Area

### 2.8.1 Area Description

The Valley Electric Association (VEA) transmission system is comprised of 230 kV and 138 kV facilities under ISO control. GridLiance West Transco, LLC is now the Transmission Owner for the 230kV facilities in the VEA area. All the distribution load in the VEA area is supplied from the 138 kV system which is mainly supplied through 230/138 kV transformers at Innovation, Pahrump and WAPA's Amargosa substations. The Innovation and Pahrump 230 kV substations are connected to the NV Energy's Northwest and WAPA's Mead 230 kV substations through two 230 kV lines.


The VEA system is also electrically connected to neighboring systems through the following lines:

- Amargosa – Sandy 138 kV tie line with WAPA;
- Jackass Flats – Lathrop Switch 138 kV tie line with NV Energy (NVE);
- Mead – Pahrump 230 kV tie line with WAPA; and
- Northwest – Desert View 230 kV tie line with NV Energy.

### 2.8.2 Area-Specific Assumptions and System Conditions

The Valley Electric Association area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the VEA area study are provided below.

Table 2.8-1: VEA Area load and generation assumptions

| S. No. | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response | | Battery Storage (MW) | Solar | | Wind | | Hydro | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| 1 | 2019 Summer Peak | Baseline | 2019 summer peak load conditions. | 141 | 0 | 0 | 0 | 141 | 0 | 0 | 0 | 15 | 14.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | 2022 Summer Peak | Baseline | 2022 summer peak load conditions. | 144 | 0 | 0 | 0 | 144 | 0 | 0 | 0 | 15 | 14.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | 2027 Summer Peak | Baseline | 2027 summer peak load conditions. | 153 | 0 | 0 | 0 | 153 | 0 | 0 | 0 | 15 | 14.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | 2019 Spring Light Load | Baseline | 2022 spring shoulder load day with maximum wind and solar output . | 79 | 0 | 0 | 0 | 79 | 0 | 0 | 0 | 15 | 14.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | 2022 Spring Off-peak | Baseline | 2019 spring minimum load conditions. | 72 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 15 | 14.6 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | 2022OP Renewable Generation Addition | Sensitivity | 2022 spring off-peak with additional future renewable generation projects | 94 | 0 | 0 | 0 | 94 | 0 | 0 | 0 | 315.6 | 315.2 | 0 | 0 | 0 | 0 | 0 | 0 |

All previously-approved transmission projects were modeled in the Valley Electric Association area assessment in accordance with the general assumptions described in section 2.3. There are no transmission upgrades modeled in the 2019 study cases. The transmission upgrades modeled in the 2022 and 2027 study cases are:

- New Charleston – Vista 138 kV Line.
- New Bob 230kV switching station that loops into the existing Pahrump-mead 230kV Line.
- A new transmission interconnection tie between the planned Bob 230kV switching station and Eldorado substation.

### 2.8.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The Valley Electric Association area steady state assessment identified several Category P6 related low/high voltages issues under various scenarios. The issues identified can be mitigated by the existing Under Voltage Load Shedding (UVLS) scheme. The assessment also identified several Category P1, P4, P6 and P7 related thermal overloads in the sensitivity case which can be mitigated by a proposed RAS scheme or congestion management. The stability analysis performed in the VEA area assessment did not identify any transient issues that require mitigation.

As a result, system additions and upgrades were not identified for the VEA area.

### 2.8.4 Request Window Project Submissions

The ISO received two request window submissions for the Valley Electric Association area in this planning cycle. Below is a description of both proposals followed by ISO comments and findings.

*New 138/24.9kV Distribution Substation Project*

Valley Electric Association, Inc. (VEA) submitted this project for ISO's concurrence. The project will construct a new 138/24.9kV distribution substation looping into the existing Thousandaire-Gamebird 138 kV line. The new station will have 80 MVA capacity to serve load. The transmission facility components of the project have an estimated cost of $4.4 million. The expected in-service date is December 1, 2019.

The purpose of the proposed project is to provide sufficient capacity to serve the load growth in the area. The ISO has reviewed the submittal and has not identified any concerns with the project.

*Valley-Innovation 230kV Transmission Line Project*

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes installing a new 230kV bus and a 230/138kV transformer at Valley Substation and building a new 40-mile 230kV line between Valley 230kV Substation and Innovation 230kV

Substation. The project has an estimated cost of $40 million. The expected in-service date is September 30, 2022.

The proposed project would increase the transmission capacity, facilitate the delivery of renewable generation out of Nevada into California and mitigate some of the overload issues found in the sensitivity scenario. However, the issues were only identified in one sensitivity case and could be mitigated by a Remedial Action Scheme (RAS) alternative which would have a lower cost and an earlier in-service date. It was also confirmed that the proposed RAS schemes would be consistent with the ISO RAS guidelines as stated in the ISO Planning Standards. For these reasons, the transmission line project was not found to be needed.

### 2.8.5 Consideration of Preferred Resources and Energy Storage

The Valley Electric Association area assessment did not identify a need for additional preferred and storage resources in the area.

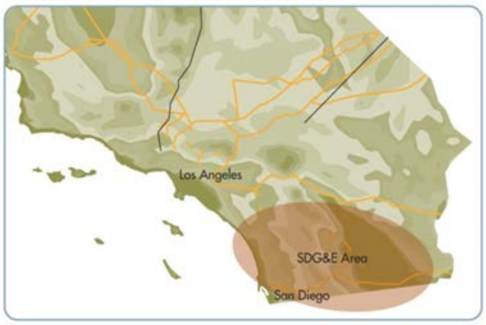
### 2.8.6 Recommendation

The Valley Electric Association area assessment identified several Category P6 related low/high voltages issues in the base scenarios and several thermal overloads issues for Category P1, P4, P6 and P7 outages in the sensitivity scenario. Existing UVLS, future RAS schemes and congestion management are recommended to address the issues.

## 2.9 SDG&E Area

### 2.9.1 San Diego Local Area Description

SDG&E is a regulated public utility that provides energy service to 3.6 million consumers through 1.4 million electric meters and more than 873,000 natural gas meters in San Diego and southern Orange counties. The utility's service area spans 4,100 square miles from Orange County to the US-Mexico border, covering two counties and 25 communities.




The SDG&E system, includes its main 500/230 kV and 138/69 kV sub-transmission systems. The geographical location of the area is shown in the adjacent illustration. Its 500 kV system consists of the Southwest Powerlink (SWPL) and Sunrise Powerlink (SRPL). The 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego with an underlying 138 kV and 69 kV sub-transmission system. Rural customers in the eastern part of San Diego County are served exclusively by a sparse 69 kV system.

The ISO approved various transmission projects presented in chapter 7 for this area in previous planning cycles, which will maintain the area reliability and deliverability of resources in the near future. Some of the major system additions are the Sycamore-Penasquitos 230 kV line, the synchronous condensers at SONGS and San Luis Rey, the Southern Orange County Reliability Enforcement (SOCRE), and the Suncrest SVC (static VAR compensator) project.

The interface of San Diego import transmission (SDIT) consists of SWPL, SRPL, the south of San Onofre (SONGS) transmission path, and the Otay Mesa-Tijuana 230 kV transmission tie with CENACE. The San Diego area relies on internal generation and import through SDIT to serve electricity customers. The area has a forecasted 1-in-10 peak sales load of 4,555 MW in 2027 after incorporating a load reduction of 574 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 401 MW of additional achievable energy efficiency (AAEE).

The area currently has approximately 6,517 MW of grid-connected generation, of which a total of 1026 MW of generation, including once-through-cooled (OTC) units, are scheduled to be retired by the end of 2018. The California Public Utilities Commission (CPUC) has approved a total of 940 MW of conventional generation and preferred resources for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the Encina generating plants.

### 2.9.2 Area-Specific Assumptions and System Conditions

The steady state and transient stability assessments on the SDG&E main and sub-transmission systems were performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the five base cases, stability model data and contingencies that were used in the assessments. In addition, specific assumptions on load of demand-side and resources of supply-side along with transmission in the baseline and sensitivity scenarios are shown in the table below.

**Demand-Side Assumptions**

The summer peak cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the load forecast assumptions including load reduction impact of BTM PV and AAEE on demand side. The load forecast provided by CEC are net demand values including load reduction and system losses. The summer light load and spring off-peak cases assume approximately 35 percent and 65 percent of the net peak load, respectively.

**Supply-Side Assumptions**

The table below also provides a summary of the supply-side assumptions modeled in the SDG&E main and sub-transmission systems assessments including conventional and renewable generation, and along with energy storage. A detailed list of existing generation in the area is included in Appendix A.

**Transmission Assumptions**

Transmission modeling assumptions on existing and previously planned transmission projects are consistent with the general assumptions described in section 2.3 with the exception of the Mission-Penasquitos 230 kV circuit project. The Mission-Penasquitos 230 kV circuit project was approved in the ISO's 2014-2015 Transmission Plan. However, the potential need for this project changed after the CPUC approved an alternative line route for the Sycamore-Pensaquitos 230 kV project in October 2016, which resulted in material changes to the transmission system configuration. The ISO re-evaluated the need for the Mission-Penasquitos 230 kV circuit project and other previously-approved projects in this planning cycle due to transmission system development and load demand reduction driven by various state regulatory programs.

Table 2.9-1: SDG&E load and generation assumptions

| Case ID | Study Case | Scenario Type | Description | Gross Load (MW) | AAEE (MW) | BTM-PV | | Net Load (MW) | Demand Response* | | Solar | | Wind | | Energy Storage* | | Thermal | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Installed (MW) | Output (MW) | | Total (MW) | D2 (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) | Installed (MW) | Dispatch (MW) |
| B1 | 2019SP | Baseline | 2019 Summer Peak Load | 5231 | 151 | 867 | 327 | 4,753 | 64 | 34 | 1,373 | 755 | 601 | 198 | 98 | 98 | 3,918 | 3,113 |
| B2 | 2022SP | Baseline | 2022 Summer Peak Load | 5345 | 241 | 1077 | 400 | 4,704 | 64 | 34 | 1,373 | 755 | 701 | 231 | 124 | 98 | 3,918 | 2,112 |
| B3 | 2027SP | Baseline | 2027 Summer Peak Load | 5530 | 401 | 1563 | 574 | 4,555 | 64 | 34 | 1,373 | 755 | 701 | 231 | 124 | 98 | 3,918 | 2,753 |
| B4 | 2019LL | Baseline | 2019 Spring Light Load (35% of the peak) | 1703 | 53 | 867 | 0 | 1,650 | 0 | 0 | 1,373 | 0 | 701 | 701 | 124 | -98 | 3,918 | 676 |
| B5 | 2022OP | Baseline | 2022 Spring Off-Peak (65% of the peak) | 4061 | 158 | 1,077 | 872 | 3,031 | 0 | 0 | 1,373 | 1,112 | 701 | 673 | 124 | 0 | 3,918 | 3,555 |
| S1 | 2022SP HL-PS | Sensitivity | High CEC Load Forecast & Peak-Shift | 5553 | 241 | 1077 | 0 | 5,312 | 64 | 34 | 1,373 | 0 | 701 | 231 | 124 | 98 | 3,918 | 3,541 |
| S2 | 2019SP PS | Sensitivity | 2019 CEC Peak-Shift | 5111 | 151 | 867 | 0 | 4,960 | 64 | 34 | 1,373 | 0 | 601 | 198 | 98 | 98 | 3,918 | 3,561 |
| S3 | 2027SP PS | Sensitivity | 2027 CEC Peak-Shift | 5716 | 401 | 1563 | 0 | 5,315 | 64 | 34 | 1,373 | 0 | 701 | 259 | 124 | 98 | 3,918 | 3,359 |
| S4 | 2022SP HRPS | Sensitivity | Heavy Renewable Output | 5345 | 241 | 1077 | 400 | 4,704 | 64 | 34 | 1,373 | 1,195 | 701 | 259 | 124 | 98 | 3,918 | 1,574 |
| S5 | 2022SP HNB | Sensitivity | Heavy NB Flow via the SONGS path | 5345 | 241 | 1077 | 400 | 4,704 | 64 | 34 | 1,373 | 1,195 | 701 | 231 | 124 | 98 | 3,918 | 3,745 |

### 2.9.3 Assessment Summary

The ISO conducted a detailed reliability assessment for the SDGE area based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. The results identified potential reliability concerns that are discussed in Appendix B. The following summarizes the reliability assessment results for the SDG&E study areas, including the SDG&E 500/230 kV main system and its 138/69 kV sub-transmission system. The results identify or confirm needs for transmission additions or operation modifications including remedial action schemes (RAS) to meet applicable reliability standards in the planning horizon.

The steady state assessment of the baseline scenarios identified a total of fifty-nine thermal overload and voltage concerns under Category P1/P2/P3/P6/P7 contingencies in the SDG&E main and sub-transmission systems. Most of the concerns can be mitigated in the planning horizon by operation procedures. Five of them need to be mitigated by upgrading the network or relying on recommended operational mitigations including RAS. In addition, two previously-approved projects in the area are no longer needed due to system configuration change and load reduction. Please refer to Appendix B for details on these concerns and associated mitigations. The stability analysis performed did not identify transient issues that require mitigation. The sensitivity scenarios assessment identified similar or more severe concerns compared to the baseline scenarios.

### 2.9.4 Request Window Project Submissions

The ISO received a total of nine project submittals through the 2017 request window submission for the SDG&E main and sub-transmission systems. Below is a description of each proposal followed by ISO comments and findings.

*Mission-San Luis Rey Series Compensation*

This project involves installation of a thyristor-controlled series compensation on the two existing Mission-San Luis Rey 230 kV lines (TL23001/TL23004). The project was proposed to increase northbound transfer capability from the San Diego area to the Los Angeles Basin by balancing the 230 kV system impedances. The project has an estimated cost of $41.3 million and expected in-service date of June, 2019.

The ISO has not identified a reliability need for this project despite the fact that the project could partially addresses the thermal overload congestions on the Encina-San Luis Rey 230 kV path and the San Marcos-Melrose Tap 69 kV line during system off-peak conditions. However, the thermal overload congestion can be mitigated in the ISO market by re-dispatching generation in the San Diego area and LA Basin. The ISO's further evaluation confirmed that current congestion management is sufficient to eliminate the overload concern without resulting in significant congestion cost in the ISO market within the 10-year planning horizon. More detail on the economic planning study can be found in chapter 4.

*Miguel-Mission Lines Reconductor and Series Compensation*

The Miguel-Mission 230 kV lines reconductoring and series compensation project was received as a transmission upgrade mitigation to address the overload concerns on the Silvergate-Old Town and Bay Blvd-Silvergate 230 kV lines for category P6. The scope of the project includes reconductoring approximate 8 miles of 230 kV sections on TL23022 and TL23023 from the Mission 230 kV substation to Fanita Junction to achieve a continuous rating of 912 MVA, along with adding 50~70% series compensation on each of the lines. The project has an estimated cost of $73.2 million and expected in-service date of June 1, 2019.

The ISO has not identified a reliability need for this project. The thermal overload concerns can be mitigated by relying on system adjustment or operation procedure after the first contingency in order to prepare the system for the second contingency.

*Penasquitos-Old Town 230 kV Phase Shifting Transformer*

This proposed project was received as a transmission upgrade mitigation to substitute for the Mission-Penasquitos 230 kV line project that the ISO is recommending be canceled. The project includes installation of a phase shifting transformer in series with the Old Town-Penasquitos 230 kV Line (Tl23013) along with a four-breaker scheme to also manage flow in the 230/138 kV system under certain system conditions. The project has an estimated cost of $71.9 million and an expected in-service date of June 2019.

The ISO has not identified a reliability need for the project since no reliability concerns were identified on the TL13810 Friars-Doublet Tap 138 kV line with cancellation of the Mission-Penasquitos 230 kV circuit project. More detail on the previously identified overload concern on TL13810 Friars-Doublet Tap 138 kV line is discussed in Appendix B.

*Southwest Powerlink HVDC Conversion*

This project was re-submitted as a reliability, economic, and policy-driven transmission project that would purportedly mitigate the identified thermal overload concerns in SWPL/SRPL and provide regional and interregional benefits in the southern California. The project would convert Southwest Powerlink (SWPL) to a three-terminal HVDC system with two fully independent poles at the North Gila, Imperial Valley, and Miguel 500 kV substations, along with system configuration modification in Sunrise Powerlink and the Miguel 500/230 kV substation. The project has a preliminary cost estimate of $900~1000 million and a proposed in-service date of June 2026.

The ISO conducted a high-level evaluation of the need for this project and found that the reliability concerns in SWPL/SRPL can be addressed by the proposed operational mitigations including bypassing the 500 kV series capacitors in SWPL/SRPL, and the SCR-SX 230 kV and modified Miguel bank #80/#81 RAS, which are discussed above. In addition, there are some uncertainties associated with the policy need for the proposed HVDC project, such as the renewable resource locations for achieving the state's 50 percent RPS goal, as well as the system impact and engineering feasibility of the multi-terminal HVDC configuration. The ISO's preliminary assessments demonstrated that the local capacity requirement in the San Diego and Imperial Valley sub-area would not be significantly reduced by the HVDC project. With the HVDC project modeled, the local capacity requirement continued to be driven either by potential voltage instability in the San Diego area or by contingency flows between the IID and SDG&E systems and would remain at a similar level. Some additional power flow concerns in APS and the San Diego 230 kV systems could also surface. Accordingly, the project was not found to be needed.

*San Diego/LA Basin Transmission Interconnection*

This proposed project was submitted as a reliability, economic, and policy-driven transmission project that is intended to enhance reliability in the region, meet regulatory requirements, and mitigate needs caused by the possible closure of Aliso Canyon Natural Gas Storage facility. The inclusion of the project could provide additional import capacity into the region through a new 500/230 kV transmission path between the LA Basin and San Diego/Imperial Valley areas, and reduce local capacity requirements in a highly populated region. The project includes:

- building a new 500 kV transmission line from the planned Alberhill 500 kV substation in SCE to a new 500 kV Sycamore Canyon substation with a 500/230 kV transformer installed
- Installing a 3rd 500/230 kV transformer at Suncrest Substation and building two 230 kV transmission circuits by looping existing Miguel–Sycamore Canyon 230 kV transmission line to the Suncrest 230 kV substation

The preliminary cost estimate is $500 million with a proposed in-service date of June, 2025.

The ISO conducted a high-level need evaluation of the project and found that the proposed operational mitigations discussed above can effectively address the overload concerns in SWPL/SRPL. In addition, there are some uncertainties associated with the need and feasibility of this project, such as routing/permitting viability and the future operational status of the Aliso Canyon Natural Gas Storage facility. Accordingly, the project was not found to be needed.

*Suncrest 500/230 kV Transformers Rating Increase*

In this planning cycle, the ISO confirmed previously identified thermal overload concerns on the Suncrest banks for category P6 contingencies, and SDG&E confirmed that new 30-minute emergency ratings on the two banks could be developed by upgrading the size of the conductors connecting the transformers to the bus facilities. The new 30-minute ratings could be over 20% higher and would defer the need for a new RAS dropping generation in the greater Imperial Valley area. The project has an estimated cost less than one million dollars and an expected in-service date of June 1, 2018. The project was found to be needed.

*Otay 69 kV Reconfiguration Project*

This project is proposed to address the overload concerns in the Otay area. Several P1, P2.1, and P6 thermal concerns on the 69 kV lines out of Otay, San Ysidro, and Imperial Beach were identified, and the proposed project would mitigate all of the concerns. The estimated cost of the project is between $36 million and $47 million. The project includes:

- The removal of taps in Otay Lake Tap (TL649A/D/F) and Otay Tap (TL623A/B/C).
- Combine TL649D (San Ysidro - Otay Lake Tap) and TL649A (Otay Lake Tap – Otay) to create a single TL69XX line (San Ysidro - Otay) and reconductor TL69XX to achieve a 97/136 MVA rating.
- Extend TL649F (Border Tap - Otay Lake Tap) 2 mi to Otay to create a new TL649A (Border Tap – Otay) with a 97/136 MVA rating.
- Combine TL623B (IB – Otay Tap) and TL623A (Otay – Otay Tap) to create a single TL623 and reconductor the portion of TL623B to achieve a 137 MVA continuous rating.
- Extend TL623C (SY – Otay Tap) 0.5 miles into Otay to create a new TL69YY line (SY-Otay) with a 102 MVA continuous rating
- Reconductor TL647 (BB-IB) to achieve a 137 MVA continuous rating.

The ISO has identified a partial reliability need for this project. Under non-coincidence peak load assumptions in all peak cases, the Otay Tap-San Ysidro 69 kV line (TL623C) would be overloaded if Otay Lake Tap-San Ysidro 69 kV line (TL649D) is out of service, and vice versa. The P1 and P2.1 thermal concerns could be mitigated by reconductoring both TL623C and TL649D 69 kV lines, and the estimated cost is between $6.5 million and $8.4 million. The alternative is to install preferred resources at the San Ysidro 69 kV substation. Two sets of 2-hour battery with 5 MW of capacity could be installed to mitigate the thermal overloads on the TL623C and TL649D lines, and the estimated cost is about $13 million. Since the alternative option of installing preferred resources is more expensive than the reconductor option, the ISO found the reconductor option is needed to maintain the reliability of the 69 kV network in the San Ysidro area.

The ISO has not identified a reliability need for the remainder of this project. The P6 thermal overload concerns can be mitigated by relying on system adjustment or operation procedure after the first contingency without causing power flow concern for the second level contingencies.

*Mira Sorrento Loop-in Project*

This project was proposed to address the overload concerns in the Beach Cities district. Several P6 and P7 thermal concerns on the 69 kV lines out of Penasquitos, Mira Sorrento, Genesee, UCM, Torrey Pines, Dunhill, and Doublet substations were identified, and the proposed project would mitigate all of the concerns in the Peak base cases. The estimated cost of the project is between $10 million and $13 million. The project opens Eastgate-Penasquitos 69 kV line (TL661) and loops into the Mira Sorrento substation.

The ISO has not identified a reliability need for this project. Even though there is no system connected generation in this load pocket to relieve the overloads, the P6 and P7 thermal overload concerns can be mitigated by load shedding. Up to 30 MW of load may be shed to mitigate the overloads. Moreover, the project does not mitigate all the P6 concerns in the Peak Shift sensitivity cases. Several P6 thermal concerns are still identified in the Beach Cities district in the Peak Shift sensitivity cases with the transmission upgrade modeled.

*Boulevard East Phase Shifter Project*

This project was proposed to address the overload concerns in the Mountain Empire district. Several P2 to P7 contingencies will result in consequential load loss at six substations in the area after the retirement of Descanso-Santa Ysabel 69 kV line (TL626) in June 2018. This project will add a second permanent source to the six substations and facilitate the 138 kV voltage and VAR control for the system operators at the Mission substation. The estimated cost of the project is between $13 million and $16 million. The project uses the existing normally opened Boulevard East-Crestwood 69 kV line (TL6931) and replaces the existing Boulevard East 138/69 kV transformer with a new 100 MVA +/- 45-degree Phase Shifting Transformer. The old Boulevard East 138/69 kV transformer will be used to replace the under-rated 138/69 kV transformer at the Mission substation allowing better 138 kV voltage and VAR control for the system operators.

The ISO has not identified a reliability need for this project. Even though there is no permanent generator in this load pocket that can be dispatched to provide a second source, the thermal overload concerns can be mitigated by shedding up to 30 MW at the six substations. Moreover, the project creates additional P1 thermal and voltage concerns in the 69 kV networks under the Eco-Miguel 500 kV contingency.

### 2.9.5 Operational Modification and RAS Mitigations

*Operational Modification Bypassing 500 kV Series Capacitors in SWPL and SRPL*

A need for normally bypassing the existing 500 kV series capacitor banks in SWPL and SRPL under summer peak load conditions were identified in the 2014-2015 ISO transmission plan. Since then, this operational modification has been confirmed and utilized in the transmission reliability, generation interconnection, and local capacity requirement planning processes. The series capacitors in the North Gila-Imperial Valley TL50002 500 kV line have been normally bypassed or de-energized in real time grid operation. The series capacitor banks in the ECO-Miguel TL50001 and Ocotillo-Suncrest TL50003 500 kV lines should also be normally bypassed seasonally after the planned Suncrest SVC project is in service (expected in 2019). The bypassing configuration would deliver maximum system benefits without causing parallel flow concerns on the CENACE system by operating with the Imperial Valley phase shifting transformers. The operational modification would provide considerable incremental benefits including but not limited to increasing generation deliverability in the greater IV area, reducing local capacity requirement in the San Diego area and LA Basin, and boosting capability of SDIT.

*Suncrest–Sycamore 230 kV lines TL23054/TL23055 RAS*

The ISO is currently working with SDG&E to implement a previously recommended Suncrest-Sycamore 230 kV lines RAS to mitigate P6 overload concerns on the Suncrest-Sycamore 230 kV lines (TL23054/TL23055). The RAS would include dropping of generation in the greater IV area and opening the remaining 230 kV line or TL50003 Ocotillo-Suncrest 500 kV line when the generation drop is not sufficient to eliminate the overload. The ISO is recommending a June 2018 in-service date for this RAS.

*Modification on Existing Miguel Banks #80 and #81 RAS*

The need for modifying the existing Miguel BK80/81 SPS was confirmed to mitigate the bank overload concern for various category P6 contingencies in the transmission planning horizon. The current RAS scheme is available to protect Miguel BK #80 and BK #81 by tripping renewable generation in the greater Imperial Valley area. The modified RAS should be designed to drop up to all of the renewable and conventional generation in the area. The modified RAS is needed to be in service by approximately 2020 when most of once-through-cooled (OTC) generation units in the southern California are retired. The ISO will continue to evaluate the required in-service date for this RAS modification.

### 2.9.6 Consideration of Preferred Resources and Energy Storage

As indicated earlier, projected amounts of up to 401 MW energy efficiency (AAEE) and up to 1,563 MW of distributed self-generation were used in the study scenarios for the San Diego area, which reduce up to a total of 17.6 percent of the area peak load. This load reduction avoided, deferred, or helped mitigate various significant reliability concerns identified in current and previous transmission planning cycles, including but not limited to:

- Various thermal overload concerns in SWPL and SRPL for various Category P1/P3/P6 contingencies
- Voltage instability in the San Diego and LA Basin for Category P3/P6 contingencies
- The south of San Onofre Safety Net taking action for Category P6 contingency
- Bay Boulevard–Silvergate-Old Town 230 kV path overloads for Category P6/P7 contingencies
- Miguel-Mission 230 kV path overloads for Category P6 contingencies
- SCE's Ellis 220 kV south corridor for Category P6 contingency
- Cross-tripping the 230 kV tie lines with CENACE for Category P3/P6 contingencies
- Imperial Valley – El Centro 230 kV tie line for Category P3/P6 contingencies

The operational and planned energy storage amounting to 98 MW were used in the base or sensitivity scenario cases. Utilization of the resources helped reduce some of the thermal overloads identified but didn't completely alleviate them. Furthermore, about 64 MW of demand response and 26 MW of battery energy storage are modeled offline in the baseline and sensitivity scenarios cases and were dispatched as potential mitigation as needed.

In this planning cycle, no need for additional preferred resource and energy storage was identified as a cost-effective mitigation to meet reliability needs in the San Diego area. As alternatives to the recommended mitigation solutions, however, procuring additional amounts of preferred resources and energy storage in appropriate locations could be helpful to mitigate or reduce exposure to some of the reliability concerns. Table 2.9-2 lists locations in which preferred resources and energy storage were identified as potential alternatives to the recommended mitigations along with an estimated amount of the resource needed.

Table 2.9-2. Preferred resources and energy storage as alternative mitigations

| Reliability Concern | Category | Type of Concern | Recommended mitigation | Preferrerd resources and energy storage as an alternative to recommended mitigation | | |
|---|---|---|---|---|---|---|
| | | | | Peak (MW) | Duration (Hr) | Preferred Location |
| San Luis Rey-SONGS 230 kV path | P2/P4/P6/ P7 | Overload | congestion management | 500 | 0.5 | SONGS/Encina |
| Encina-San Luis Rey 230 kV path | P1/P2/P4/ P6/P7 | Overload | congestion management | 500 | 0.5 | SONGS/Encina |
| Bay Blvd-Silvergate-OldTown 230 kV path | P2/P4/P6 | Overload | Operation procedure | 120~160 | 4 | San Diego coastal stretch north of the Old Town area |
| SCE's the Ellis south 220 kV corridor | P6 | Overload | Operation procedure | 250 | 4 | San Diego and Orange counties |
| Imperial Valley-El Centro 230 kV tie | P3/P6 | Overload | Operation procedure | 350~550 | 0.5 | Imperial Valley/San Diego |

### 2.9.7 Cancellation of Previously-Approved Projects

Two previously-approved projects in the SDG&E area are no longer needed due to system configuration change and load reduction as described above. The ISO is recommending canceling these two projects.

*Mission – Penasquitos 230 kV Circuit*

The Mission-Penasquitos 230 kV circuit project was approved as a reliability project to mitigate the thermal overload concern on TL13810 Friars-Doublet Tap 138 kV line in the ISO's 2014-2015 Transmission Plan. The expected cost of the project is $30 M. The project would have utilized a de-energized portion of the Mission-San Luis Rey 230 kV line (TL23001) that would have been left behind after completion of the original Sycamore Canyon-Pensaquitos 230 kV project. However, the CPUC recently approved an alternative line route that allows the new circuit go underground directly from Sycamore Canyon to Penasquitos substation. The ISO re-evaluated the need for the Mission-Penasquitos 230 kV circuit project in this planning cycle and did not identify the thermal overload concern on TL13810 Friars-Doublet Tap 138 kV line because TL23001 remained unchanged. In addition, the ISO's further evaluations did not recognize a negative impact on generation deliverability or the local capacity requirement in the area. Therefore, the ISO is recommending canceling this project.

*Sycamore-Chicarita Reconductor Project*

The Sycamore-Chicarita Reconductor project was approved as a reliability project in the ISO's 2012-2013 Transmission Plan. The project involves replacing underground getaways, relays, jumpers and terminal equipment to mitigate overloading on the Sycamore-Chicarita 138 kV line for the P1 contingency of the Encina 138/230 kV transformer. The expected cost of the project is $0.5 to $1 million.

The ISO re-evaluated the project in this planning cycle and did not identify the need for the project to meet applicable reliability standards, generation deliverability, or local capacity requirements. The ISO is recommending canceling this project.

The ISO also re-evaluated the Sweetwater Reliability Enhancement project that was approved as a reliability project in the ISO's 2012-2013 Transmission Plan. The project will open the Sweetwater Tap and extend the line from Naval Station Metering into Sweetwater to mitigate overloading on the Sweetwater-Sweetwater Tap (TL603B) during the P1 contingency of the Bay Blvd-Silvergate 230 kV line. The ISO also identified the need for this project for generation deliverability purposes, and therefore is not making any recommendations to change or cancel this project.

### 2.9.8 Recommendation

The assessments identified a total of fifty-nine thermal overload and voltage concerns in the local SDG&E area. In response to the ISO study results and proposed alternative mitigations, a total of nine project submissions were received through the 2017 request window. The ISO evaluated the alternatives and did not find a reliability need for seven out of the nine projects, and is recommending two network upgrades and three operational mitigations including RAS as cost-effective mitigations to address the identified reliability concerns, along with preferred resources and energy storage. In addition, two previously-approved projects are recommended to be canceled due to system changes and load reduction. Below is a summary of the recommendations for the SDG&E area:

1. Otay 69 kV Reconfiguration Project (recommended for partial approval)
2. Suncrest 500/230 kV Transformers Rating Increase (recommended for approval)
3. Operational modification to normally bypass 500 kV series capacitors in SWPL/SRPL
4. Suncrest–Sycamore 230 kV lines TL23054/TL23055 RAS
5. Modification on existing Miguel Banks #80 and #81 RAS
6. Cancel the previously Mission – Penasquitos 230 kV circuit project
7. Cancel the previously-approved Sycamore-Chicarita Reconductor Project

## 2.10 Balancing Authority Area Requirements - Phasor Measurement Units on ISO Interties

As discussed in detail in section 6.4, the ISO must meet its frequency response obligation based on net actual MW interchange measurements, and for compliance purposes, frequency response reflects the change in interchange over the change in frequency for a period of time following a frequency disturbance. The ISO has identified a need to require Phasor Measurement Units (PMUs) at all interties at the boundary of its balancing authority area to provide more precision regarding the system's net actual interchange after a frequency disturbance event. The PMUs are needed to enhance the accuracy of measurements to demonstrate compliance with NERC Reliability Standard BAL-003-1.1.

The ISO proposed that PMUs be added to all ISO intertie transmission facilities to other balancing areas during the ISO 2017-2018 Transmission Planning Process Stakeholder Meeting on November 16, 2017. The ISO subsequently worked with the transmission owners and identified up to 36 tie-lines that do not have existing or planned PMUs. Based on cost information provided by the transmission owners, the total estimated cost for installing the 36 PMUs is $4.5 to $11 million.

| Transmission Owner | Estimated PMU Cost |
|---|---|
| PG&E | $2-5 million |
| SCE | $2-5 million |
| VEA/Gridliance | $0.5 to 1 million |

# Chapter 3

# 3 Policy-Driven Need Assessment

## 3.1 Study Assumptions and Methodology

### 3.1.1 33% RPS Portfolios

The CPUC policy direction to the ISO regarding renewable generation portfolios for policy-driven transmission planning purposes in the 2017-2018 transmission planning cycle via an Assigned Commissioners Ruling[84] in February, 2017. In that Assigned Commissioners Ruling, the CPUC recommended that the ISO re-use the "33% 2025 Mid AAEE" RPS portfolio – which was also used in the 2015-16 TPP and again in the 2016-2017 studies – as the base case renewable resource portfolio in the 2017-18 TPP studies.

The analysis of policy-driven needs in the 2015-2016 transmission planning cycle confirmed at the time that no additional policy-driven reinforcements were required in order to meet the needs of the renewable resource portfolio provided for this purpose.

In the 2016-2017 transmission planning cycle, when the CPUC and CEC recommended that the ISO re-use the same "33% 2025 Mid AAEE" RPS portfolio[85] used in the 2015-16 TPP studies the ISO reviewed the changes to the planning models from the 2015-2016 TPP to the 2016-2017 TPP and determined that material changes had been made to the transmission system plan base case only in the Imperial Valley area – due to changes in the plans of the Imperial Irrigation District. This recommendation was expected to have the effect that no additional major policy-driven transmission would be found to be needed until policy direction was available for moving beyond 33% to 50% RPS or higher, nor would changes be necessary to existing transmission plans and approved projects to reach 33% RPS. Accordingly, the ISO performed a generation deliverability analysis of the Imperial Valley to update the results for that one area from the 2015-2016 Transmission Plan, and complete the 2016-2017 TPP policy-driven need assessment.

In this year's cycle, the ISO again reviewed the transmission planning base cases and determined that there were no material modifications to the base cases that would require further review to confirm that further studies are necessary to accommodate the policy-driven portfolio.

The ISO notes that upgrades to the 230 kV S Line owned by the Imperial Irrigation District are being advanced as an economic-driven project as set out in chapter 4. Those upgrades will provide added benefit in increasing deliverability from the Imperial area overall, including from IID,

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[84] "Assigned Commissioner's Ruling Adopting Assumptions and One Scenario for Use in Long-Term Planning in 2017," *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements*, Proceeding No. R.16-02-007, Febraury 28, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M176/K948/176948479.PDF.

[85] Letter to Steve Berberich from President Michael Picker (CPUC) and Chairman Robert B. Weisenmiller (CEC) re: Base Case Renewable Resource Portfolio for the CAISO 2016-2017 Transmission Planning Process, dated June 13, 2016, http://www.caiso.com/Documents/2016-2017RenewablePortfoliosTransmittalLetter.pdf

beyond the needs the existing 33% renewable generation portfolio. The added deliverability is nonetheless a benefit that can be considered qualitatively in the economic assessment of the upgrades, however.

As no material changes were identified that would negatively impact the 2017-2018 results, no additional policy-driven analysis was conducted in 2017-2018 cycle other than special study activities performed for informational purposes and discussed in chapter 6.

The installed capacity of the portfolio by location and technology are shown in Table 3.1-1.

Table 3.1-1: Renewables portfolio for 2017-2018 TPP (MW)

| Zone | Biogas | Biomass | Geothermal | Hydro | Large Scale Solar PV | Small Solar PV | Solar Thermal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Riverside East** | 0 | 0 | 0 | 0 | 2308 | 13 | 696 | 0 | **3017** |
| **Imperial** | 0 | 0 | 288 | 0 | 1172 | 25 | 0 | 265 | **1750** |
| **Tehachapi** | 10 | 0 | 0 | 0 | 1007 | 98 | 0 | 538 | **1653** |
| **Distributed Solar - PG&E** | 0 | 0 | 0 | 0 | 0 | 984 | 0 | 0 | **984** |
| **Carrizo South** | 0 | 0 | 0 | 0 | 900 | 0 | 0 | 0 | **900** |
| **Nevada C** | 0 | 0 | 116 | 0 | 400 | 0 | 0 | 0 | **516** |
| **Mountain Pass** | 0 | 0 | 0 | 0 | 300 | 0 | 358 | 0 | **658** |
| **Distributed Solar - SCE** | 0 | 0 | 0 | 0 | 0 | 565 | 0 | 0 | **565** |
| **NonCREZ** | 5 | 103 | 25 | 0 | 0 | 52 | 0 | 0 | **185** |
| **Westlands** | 1 | 0 | 0 | 0 | 300 | 174 | 0 | 0 | **475** |
| **Arizona** | 0 | 0 | 0 | 0 | 400 | 0 | 0 | 0 | **400** |
| **Alberta** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 300 | **300** |
| **Kramer** | 0 | 0 | 0 | 0 | 0 | 0 | 250 | 0 | **250** |
| **Distributed Solar - SDGE** | 0 | 0 | 0 | 0 | 0 | 143 | 0 | 0 | **143** |
| **Baja** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 100 | **100** |
| **San Bernardino - Lucerne** | 0 | 0 | 0 | 0 | 45 | 0 | 0 | 42 | **87** |
| **Merced** | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **5** |
| **Grand Total** | **20** | **103** | **429** | **0** | **6832** | **2054** | **1303** | **1245** | **11986** |

**Transmission Plan Deliverability with Recommended Transmission Upgrades**

As part of the coordination with other ISO processes and as set out in Appendix DD (GIDAP) of the ISO tariff, the ISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the ISO considered queue clusters up to and including queue cluster 10.

An estimate of the generation deliverability supported by the existing system and approved transmission upgrades is listed in Table 3.1-2 through Table 3.1-5. The transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas not listed, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 10.

Table 3.1-2: Deliverability for Area Deliverability Constraints in SDG&E area

| Area Deliverability Constraint | Renewable Zones | Deliverability (MW) |
|---|---|---|
| East of Miguel Constraint | Arizona | 3189 ~ 4231 |
| | Baja | |
| | Imperial | |

Table 3.1-3: Deliverability for Area Deliverability Constraints in SCE area

| Area Deliverability Constraint | Renewable Zones | Deliverability (MW) |
|---|---|---|
| Desert Area Constraint | Mountain Pass | ~9,500 |
| | Riverside East | |
| | Tehachapi (Big Creek and Ventura) | |
| | Distributed Solar – SCE (Big Creek and Ventura) | |
| | Imperial | |
| | Nevada C | |
| Barre – Lewis 220 kV flow limit | Riverside East | ~6,100 |
| | Imperial - SDG&E | |
| | San Diego South | |
| Lugo AA Bank capacity limit | Kramer | ~1,100 |
| | San Bernardino - Lucerne | |
| Lugo - Pisgah 220kV flow limit | San Bernardino – Lucerne | ~450 |
| South of Kramer 220kV flow limit | Kramer | ~380 |
| Antelope – Vincent flow limit | Tehachapi | ~8,000 |
| | Distributed Solar – SCE (Big Creek) | |

Table 3.1-4: Deliverability for Area Deliverability Constraints in VEA area

| Area Deliverability Constraint | Renewable Zones | Deliverability (MW) |
|---|---|---|
| Bob – Mead 230kV Constraint | Mountain Pass | 1,500 ~ 1,850 |
| | Nevada C | |

Table 3.1-5: Deliverability for Area Deliverability Constraints in PG&E area

| Area Deliverability Constraint | Renewable Zones | Deliverability (MW) |
|---|---|---|
| Gates 500/230kV Bank Constraint | Westlands | 5,200 ~ 6,400 |
| Los Banos 500/230kV Bank Constraint | Westlands | 4,000 ~ 4,300 |

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# Chapter 4

# 4 Economic Planning Study

## 4.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO.

Each year's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan. The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. This type of economic benefit is normally categorized as an energy benefit or production benefit. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

All network upgrades identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. This ensured that all economic planning studies would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan. The economic planning study was then performed to identify additional cost-effective network upgrades to mitigate grid congestion and increase production efficiency within the ISO.

Other benefits are also taken into account on a case by case basis using a range of other tools, such as power flow-type study that is normally used to identify capacity benefits, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. The potential economic benefits are quantified as reductions of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[86]

[86] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

## 4.2 Technical Study Approach and Process

Different components of benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost 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 to minimize 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 of ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles.

Second, other benefits including capacity benefits are also assessed. Capacity benefits may include system resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a network upgrade for an 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 or accessing an otherwise inaccessible resource.

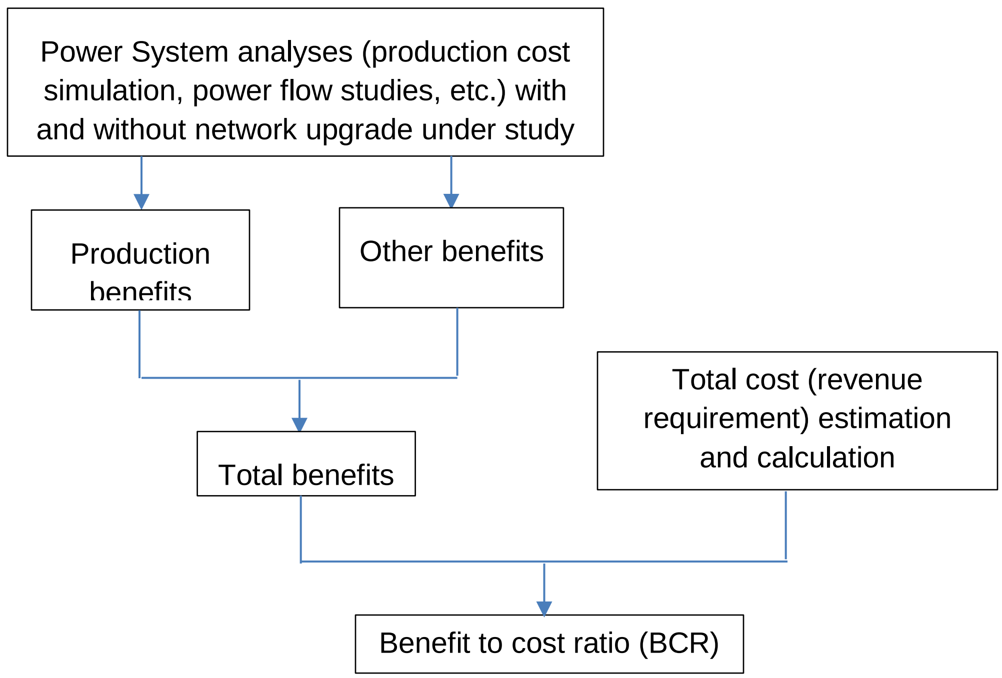
The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings.

In addition to the production and capacity benefits, any other benefits — where applicable and quantifiable — can also be included. However, it is not always viable to quantify social benefits into dollars.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement, as described in the TEAM document, of the project under study. To justify a proposed network upgrade, 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 economic-driven project. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven project.

The technical approach of economic planning study is depicted in Figure 4.2-1. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 4.2-1: Technical approach of economic planning study



## 4.3 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

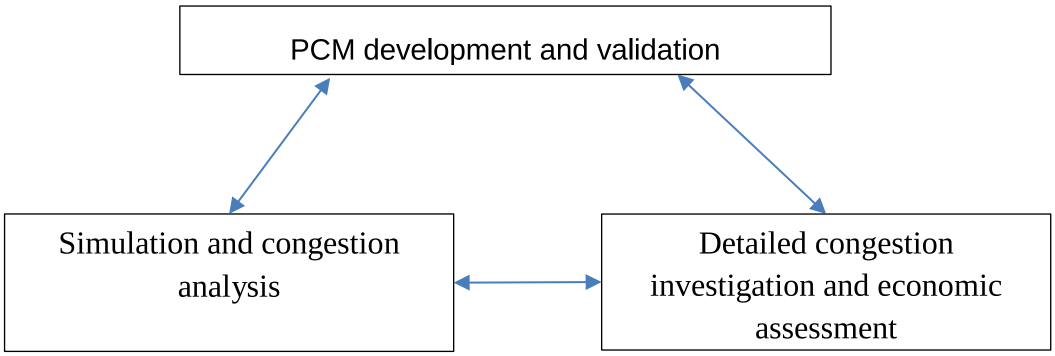
- Network model (transmission topology, generator location, and load distribution)
- Transmission operation model, such as transmission constraints, nomograms, phase shifters, etc.
- Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, renewable profiles.
- Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE.
- Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission, etc.

Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission line or transformers, or on interfaces or nomograms, and can be under normal or contingency conditions. In congestion analysis, all aspects of results may need to be investigated, such as locational marginal price (LMP), unit commitment and dispatch, renewable curtailment, and the hourly power flow results under normal or contingency conditions. Through these investigations, congestion can be validated, or some data or modeling issues can be identified. In either situation, congestion analysis is used for database validation. The simulated power flow pattern is also compared with the historical data for validation purpose, although it is not necessary to have identical flow pattern between the simulation results and the historical data. There are normally many iterations between congestion analysis and PCM development.

In the detailed congestion investigation and economic assessment step, the ISO quantifies economic benefits for each identified network upgrade alternative using the production cost simulation and other means. From the economic benefit information a cost-benefit analysis is conducted to determine if the identified network upgrades provide sufficient economic benefits to be found to be needed. Net benefits are compared with each other where the net benefits are calculated as the gross benefits minus the costs to compare multiple alternatives that would address identified congestion issues. The most economical solution is the alternative that has the largest net benefit. In this step, the PCM and the congestion results are further validated.

Normally there are a number of iterations among these three steps through the entire economic planning study process. Figure 4.3-1 shows these components and their interaction.

Figure 4.3-1: Steps of production cost simulation in Economic planning



## 4.4 Production cost simulation tools and database

The ISO used the software tools listed in Table 4.4-1 for this economic planning study.

Table 4.4-1: Economic Planning Study Tools

| Program name | Version | Functionality |
|---|---|---|
| ABB GridView™ | 9.7.26.20 (compatible with version 10.1.3) | The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year. |

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop a 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

## 4.5 ISO Production Cost Model Development

This section summarizes the major assumptions of system modeling used in PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the TEPPC database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the ISO's market participant portal once the study is finalized.

### 4.5.1 Modeling assumptions

The ISO's economic planning production cost model (PCM) used the 2016~2017 planning cycle PCM as a starting database, which was based on the Transmission Expansion Planning Policy Committee (TEPPC) 2026 production cost simulation common case v1.3[87], and incorporated the validated changes in the consequent versions of TEPPC Common Cases and the Western Planning Regions Anchor Data Set (ADS) PCM seed case. Using this database the ISO developed the base cases for the ISO production cost simulation. These base cases included the modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section.

### 4.5.2 Network modeling

The ISO normally develops the economic planning PCM starting from a WECC common database, which uses a nodal model to represent the entire WECC transmission network. However, the network model in the WECC common database may be based on a power flow case that is different from the ISO's reliability power flow cases. In the previous planning cycles, an incremental update approach was used for the network model update, in which mainly the bulk system model in the PCM was updated piecemeal to match the ISO's reliability power flow cases. Starting in this 2017-2018 planning cycle, the ISO took a more comprehensive approach and modified the network model for the ISO's system to exactly match the reliability assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and reliability assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in reliability assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

### 4.5.3 Load demand

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load condition across the ISO transmission network. The California load data was drawn from the California Energy Demand Forecast 2017-2027, Revised Electricity Forecast adopted by California Energy Commission

87 "TEPPC 2026 V1.3" dataset released in August 2016

(CEC) on January 25, 2017 using the Mid Case LSE and Balancing Authority Forecast spreadsheet of January 12, 2017. Other WECC areas load remained the same as in the PCM of last planning cycle.

Load modifiers, including DR, DG, and AAEE, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

### 4.5.4 Generation resources

Generator locations and installed capacities in the PCM are consistent with the 2017-2018 reliability assessment power flow cases, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

### 4.5.5 Transmission constraints

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (i.e., flowgates) and nomograms. However, the original TEPPC database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the California ISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the California ISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled, including COI, Path 26, and Path 15. These nomograms were developed in ISO's reliability assessments or identified in the operating procedures.

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

### 4.5.6 Renewable curtailment cost

As recommended by CPUC and CEC on the study assumptions for transmission planning[88], multi-tiers of renewable curtailment cost were implemented in 2017-2018 planning cycle PCM. The implementation is summarized in Table 4.5-1

Table 4.5-1: Multi-tiers of renewable curtailment cost

| Tier | Total curtailment (GWh) | Curtailment price ($/MWh) |
|---|---|---|
| 1 | <200 | -$15 |
| 2 | Between 200~12400 | -$25 |
| 3 | >12400 | -$300 |

88 http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673

## 4.6 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the proposed network upgrades. In these studies, all costs and benefits are expressed in 2016 U.S. dollars and discounted to the assumed operation year of the studied network upgrade to calculate the net present values. By default, the proposed operation year is 2021 unless specially indicated.

### 4.6.1 Cost analysis

In these studies, the "total cost" is considered to be the present value of the annualized revenue requirement in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven project, when necessary, the financial parameters listed in Table 4.6-1 are used. The net present value of the costs (and benefits) are calculated using a social discount rate of 7 percent (real) with sensitivities at 5 percent as needed.

Table 4.6-1: Parameters for Revenue Requirement Calculation

| Parameter | Value in TAC model |
|---|---|
| Debt Amount | 50% |
| Equity Amount | 50% |
| Debt Cost | 6.0% |
| Equity Cost | 11.0% |
| Federal Income Tax Rate | 35.00% |
| State Income Tax Rate | 8.84% |
| O&M | 2.0% |
| O&M Escalation | 2.0% |
| Depreciation Tax Treatment | 15 year MACRS |
| Depreciation Rate | 2.5% |

In the initial planning stage, detailed cash flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump sum capital cost estimates are provided. The ISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this study is 1.45 and is based on prior experiences of the utilities in the ISO. It should be noted that this screening approximation is generally replaced on a case by case basis with more detailed modeling if the screening results indicate the upgrades may be found to be needed.

### 4.6.2 Benefit analysis

In the ISO's benefit analysis, total benefit refers to the present value of 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 towards the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[89]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted 10th planning year - in this case, for 2027. For years beyond 2026 the benefits are estimated by extending the 2027 year benefit with an assumed escalation rate.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year's transmission planning cycle are:

- economic life of new transmission facilities = 50 years;
- economic life of upgraded transmission facilities = 40 years;
- benefits escalation rate beyond year 2027 = 0 percent (real); and
- benefits discount rate = 7 percent (real) with sensitivities at 5 percent as needed

### 4.6.3 Cost-benefit analysis

Once the total cost and benefit of a proposed network upgrade are determined a cost-benefit comparison is made. For a proposed upgrade to qualify as an economic project, the benefit has to be greater than the cost or the net benefit (calculated as gross benefit minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution.

[89] Discount of yearly benefit into the present worth is calculated by bi = Bi / (1 + d)i, where bi and Bi 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 $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

## 4.7 Congestion Analysis Results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of ISO transmission network was performed to identify which facilities in the ISO controlled grid were congested.

The results of the congestion assessment are listed in Table 4.7-1. Columns “Cost_F” and “Duration_F” were the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns “Cost_B” and “Duration_B” were the cost and duration of congestion in the backward direction. The last two columns were the total cost and total duration, respectively.

Table 4.7-1: Potential congestion in the ISO-controlled grid in 2027

| Constraints Name | Area or Branch Group | Cost_F (000 $) | Duration_F (Hrs) | Cost_B (000 $) | Duration_B (Hrs) | Cost_T (000 $) | Duration_T (Hrs) |
|---|---|---|---|---|---|---|---|
| MEAD S-BOB SS 230 kV line #1 | BOB SS (VEA) - MEAD S 230 kV line | 0 | 0 | 60,106 | 654 | 60,106 | 654 |
| COTATI-PETC_JCT 60 kV line, subject to PG&E LCR NCNB Fulton Cat C | PG&E NCNB | 8,236 | 427 | 0 | 0 | 8,236 | 427 |
| EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-Merced M 115/70 kV xfmr | PG&E/TID Exchequer | 4,666 | 2,173 | 0 | 0 | 4,666 | 2,173 |
| P45 SDG&E-CFE | Path 45 | 28 | 53 | 2,977 | 1009 | 3,004 | 1062 |
| P66 COI | COI Corridor | 1,533 | 89 | 0 | 0 | 1,533 | 89 |
| POE-RIO OSO 230 kV line #1 | PG&E POE-RIO OSO | 1,369 | 106 | 0 | 0 | 1,369 | 106 |
| MOENKOPI-ELDORDO 500 kV line #1 | Moenkopi-Eldorado 500 kV | 1,022 | 49 | 0 | 0 | 1,022 | 49 |
| OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS | SDGE IV-SD Import | 0 | 0 | 601 | 135 | 601 | 135 |
| MIDWAY-WIRLWIND 500 kV line #3 | Path 26 | 0 | 0 | 397 | 9 | 397 | 9 |
| P61 Lugo-Victorville 500 kV Line | Path 61/Lugo - Victorville | 388 | 50 | 0 | 0 | 388 | 50 |
| P24 PG&E-Sierra | Path 24 | 370 | 137 | 0 | 0 | 370 | 137 |

| Constraints Name | Area or Branch Group | Cost_F (000 $) | Duration_F (Hrs) | Cost_B (000 $) | Duration_B (Hrs) | Cost_T (000 $) | Duration_T (Hrs) |
|---|---|---|---|---|---|---|---|
| ISO v COI Summer 3-1 | COI Corridor | 298 | 5 | 0 | 0 | 298 | 5 |
| TM_VD_11-TM_VD_12 500 kV line #1 | COI Corridor | 281 | 10 | 0 | 0 | 281 | 10 |
| P26 Northern-Southern California | Path 26 | 0 | 0 | 235 | 13 | 235 | 13 |
| INYO 115/115 kV transformer #1 | SCE Inyo Phase Shifter | 217 | 2,358 | 0 | 6 | 218 | 2,364 |
| P52 Silver Peak-Control 55 kV | Path 52 Silver Peak-Control 55 kV | 0 | 0 | 200 | 2131 | 200 | 2131 |
| SUNCREST-SUNCREST TP2 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS | SDGE IV-SD Import | 174 | 16 | 0 | 0 | 174 | 16 |
| TM_TS_11-TM_TS_12 500 kV line #1 | COI Corridor | 154 | 6 | 0 | 0 | 154 | 6 |
| MARBLE 63.0/69.0 kV transformer #1 | PG&E/Sierra MARBLE transformer | 0 | 0 | 150 | 129 | 150 | 129 |
| MELRSETP-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV | SDGE North | 0 | 0 | 142 | 56 | 142 | 56 |
| IMPRLVLY-ELCENTSW 230 kV line, subject to SDGE N-1 N.Gila-Imperial Valley 500kV | IID-SDGE (S-Line) | 0 | 0 | 140 | 30 | 140 | 30 |
| RM_TM_21-RM_TM_22 500 kV line #2 | COI Corridor | 107 | 8 | 0 | 0 | 107 | 8 |
| JHINDMWD-J.HINDS 230 kV line #r1 | SCE J.HINDS-MIRAGE 230 kV line | 0 | 0 | 97 | 18 | 97 | 18 |
| DEVERS-REDBLUFF 500 kV line #2 | SCE Devers-RedBluff 500 kV line | 0 | 0 | 82 | 2 | 82 | 2 |
| EXCHEQUR-LE GRAND 115 kV line, subject to | PG&E/TID Exchequer | 75 | 26 | 0 | 0 | 75 | 26 |

| Constraints Name | Area or Branch Group | Cost_F (000 $) | Duration_F (Hrs) | Cost_B (000 $) | Duration_B (Hrs) | Cost_T (000 $) | Duration_T (Hrs) |
|---|---|---|---|---|---|---|---|
| PG&E N-1 Merced-MrcdFLLs 70 kV | | | | | | | |
| PANOCHE-GATES 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV | Path 15/CC | 0 | 0 | 68 | 2 | 68 | 2 |
| COTTLE-MELONES 230 kV line #1 | PG&E Fresno | 0 | 0 | 67 | 9 | 67 | 9 |
| KEARNEY-HERNDON 230 kV line #1 | PG&E Fresno | 41 | 4 | 0 | 0 | 41 | 4 |
| ENCINATP-SANLUSRY 230 kV line, subject to SDGE N-1 EN-SLR 230 kV | SDGE North | 39 | 10 | 0 | 0 | 39 | 10 |
| GATES-GT_MW_11 500 kV line #1 | Path 15/CC | 0 | 0 | 33 | 3 | 33 | 3 |
| P15 Midway-LosBanos | Path 15/CC | 0 | 0 | 31 | 3 | 31 | 3 |
| OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS | SDGE IV-SD Import | 0 | 0 | 31 | 9 | 31 | 9 |
| J.HINDS-MIRAGE 230 kV line #1 | SCE J.HINDS-MIRAGE 230 kV line | 29 | 9 | 0 | 0 | 29 | 9 |
| SYCAMORE TP2-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS | SDGE IV-SD Import | 27 | 2 | 0 | 0 | 27 | 2 |
| OTAYMESA-TJI-230 230 kV line, subject to SDGE N-2 Sycamore-Suncrest 230 kV #1 and #2 with RAS | SDGE IV-SD Import | 0 | 0 | 26 | 9 | 26 | 9 |
| MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV | PG&E GBA | 0 | 0 | 21 | 3 | 21 | 3 |
| RM_TM_11-RM_TM_12 500 kV line #1 | COI Corridor | 20 | 2 | 0 | 0 | 20 | 2 |

| Constraints Name | Area or Branch Group | Cost_F (000 $) | Duration_F (Hrs) | Cost_B (000 $) | Duration_B (Hrs) | Cost_T (000 $) | Duration_T (Hrs) |
|---|---|---|---|---|---|---|---|
| MIGUEL-MIGUELMP 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #2 with RAS | SDGE IV-SD Import | 0 | 0 | 11 | 1 | 11 | 1 |
| NRS 230/115 kV transformer #1 | PG&E GBA | 8 | 3,902 | 0 | 0 | 8 | 3,902 |
| GRIDLEY-LIVE OAK 60 kV line, subject to PG&E LCR Sierra Pease Cat C 2026 | PG&E LCR Sierra Cridley-Live Oak 60 kV | 3 | 1 | 0 | 0 | 3 | 1 |
| LS ESTRS 230/230 kV transformer #1 | PG&E GBA | 2 | 1,094 | 0 | 0 | 2 | 1,094 |

Table 4.7-2 summarizes the potential congestion across specific branch groups and local capacity areas. The branch group or local area information was provided in the second column in Table 4.7-1. The branch groups were identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestions subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results are ranked based on the 2027 congestion cost.

Table 4.7-2: Aggregated potential congestion in the ISO-controlled grid in 2027

| No | Aggregated congestion | 2027 | |
|---|---|---|---|
| | | Costs (M$) | Duration (Hr) |
| 1 | BOB SS (VEA) - MEAD S 230 kV line | 60.11 | 654 |
| 2 | PG&E NCNB | 8.24 | 427 |
| 3 | PG&E/TID Exchequer | 4.74 | 2,199 |
| 4 | Path 45 | 3.00 | 1,062 |
| 5 | COI Corridor | 2.39 | 120 |
| 6 | PG&E POE-RIO OSO | 1.37 | 106 |
| 7 | Moenkopi-Eldorado 500 kV | 1.02 | 49 |
| 8 | SDGE IV-SD Import | 0.87 | 172 |
| 9 | Path 26 | 0.63 | 22 |
| 10 | Path 61/Lugo - Victorville | 0.39 | 50 |
| 11 | Path 24 | 0.37 | 137 |
| 12 | SCE Inyo Phase Shifter | 0.22 | 2,364 |
| 13 | Path 52 Silver Peak-Control 55 kV | 0.20 | 2,131 |
| 14 | SDGE North | 0.18 | 66 |
| 15 | PG&E/Sierra MARBLE transformer | 0.15 | 129 |
| 16 | IID-SDGE (S-Line) | 0.14 | 30 |
| 17 | Path 15/CC | 0.13 | 8 |
| 18 | SCE J.HINDS-MIRAGE 230 kV line | 0.13 | 27 |
| 19 | PG&E Fresno | 0.11 | 13 |
| 20 | SCE Devers-RedBluff 500 kV line | 0.08 | 2 |
| 21 | PG&E GBA | 0.03 | 4,999 |
| 22 | PG&E LCR Sierra Gridley-Live Oak 60 kV | 0.00 | 1 |

In this planning cycle, detailed investigations were conducted on the constraints that may have a large impact on the bulk system and showed recurring congestion. Specifically, these constraints selected for further analysis were Bob SS to Mead S 230 kV line, S-Line (IID's El Centro to SDGE's Imperial Valley 230 kV line), and San Diego North area congestion including Melrose Tap to San Marcos 69 kV line and Encina Tap to San Luis Rey 230 kV line. The detailed analysis results are in Section 4.9.

Other constraints were also analyzed, but not at the same detailed level for different reasons as discussed below.

- Following 2016-2017 planning cycle, the ISO continued to model in the PCM the same COI planning nomograms developed by the ISO and the annual scheduled maintenances and derate provided by the facility owners. The COI congestion went up slightly in this planning cycle comparing to the last planning cycle, especially where congestion was observed on the downstream bulk system such as Round Mountain to Table Mountain 500 kV lines, and South of Table Mountain 500 kV lines. The congestion change is not material, however, and therefore no further detailed study was conducted on COI congestion in this planning cycle. The ISO will continue to monitor COI congestion in future planning cycles.

- Most of the observed Path 45 congestion was in the direction from CFE to ISO, which is mainly due to the natural gas price difference across the border. Other factors that may impact the congestion include the renewable generators development in Imperial Valley area and its representation in the future 50% renewable portfolio, and the CFE's generator and load modeling. It is desired to have further clarity of such factors before detailed investigation needs to be conducted. The ISO will continue to monitor the congestion on Path 45 in future planning cycles.

- A detailed analysis was performed on the congestion on the Exchequer-La Grant 115 kV line in the 2015-2016 transmission planning cycle and no economic justification was identified. There is no change in circumstance for this constraint, therefore the ISO did not conduct further detailed studies.

- Congestion in PG&E North Coast North Bay (NCNB) LCR area under N-2 contingency, which is a critical contingency identified in LCR studies, was observed in this planning cycle. This congestion is related to the geothermal generator in the PG&E NCNB LCR area. The operation condition of geothermal generators such as normal output has direct impact on the congestion. These geothermal generators are owned by Independent Power Producers (IPP) or non-ISO utilities. Similar to Exchequer-La Grant congestion, with congestion mitigated the majority benefit will go to the generator owners rather than the ISO ratepayers. Therefore, the ISO did not conduct detailed economic analysis on PG&E NCNB LCR related congestion in this planning cycle. It will be monitored in the future planning cycles.

- Congestions on Path 26 and Path 15 were also identified in the previous planning cycles, and no economic justifications were seen for network upgrades identified for these congestions in those previous planning cycles. Similar to last year's studies, the congestion on Path 26 was observed mainly on the south to north direction in this planning cycle due to the retirement of Diablo Canyon Nuclear units, and increasing renewable generation in Southern California. The overall congestion cost remained similar for both Path 26 and Path 15 from the previous year. Therefore, no detailed production cost simulations or economic assessments were conducted for these two congestions. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles.

No detailed analyses on other congestions in Table 4.7-1 and Table 4.7-2 were conducted as the congestions were not sufficient for justifying upgrades, based on either the studies in previous planning cycles or engineering judgement. They will be monitored in future planning cycles and will be studied as needed.

## 4.8 Economic Planning Study Requests

As part of the economic planning study process, Economic Planning Study requests are accepted by the ISO, to be considered in addition to the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan.

### 4.8.1 Southwest Intertie Project - North

**Study request overview**

Southwest Intertie Project - North (SWIP North) is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada). The request is for ISO to study the benefits of approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen, which would be available to the ISO market upon completion of construction of SWIP North.

**Evaluation**

Table 4.8-1 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-1: Evaluating study request - Southwest Intertie Project - North

| Study Request: Southwest Intertie Project - North | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Request is for ISO to study congestion on California Oregon Intertie (COI) and Pacific AC Intertie (PACI) | • Economic studies performed by the ISO have identified congestion on COI; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant network upgrades in previous transmission plans. (Please refer to the separate discussion of COI congestion below).<br>• Economic studies performed by the ISO have not identified significant congestion on Pacific AC Intertie (PACI) |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Request states that project offers policy benefits by allowing out of state renewables to help meet the new California RPS targets: 40% in 2024, 45% in 2027 and 50% in 2030.<br>• Project will allow geographical diversity to incremental RPS build out which will help reduce locational aspects of congestion caused by over generation. This will benefit CAISO ratepayers with or without expansion of CAISO's borders as this new line will provide a | • Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes. |

| Study Request: Southwest Intertie Project - North | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| | transmission path for out of state renewables to be either directly connected to or Pseudo Tied to the CAISO Balancing Authority Area. | |
| Local Capacity Area Resource requirements | • Not addressed in submission | • No benefits identified by ISO |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • See "Delivery of Location Constrained Resource Interconnection Generators" above | • See "Delivery of Location Constrained Resource Interconnection Generators" above |
| Other | • Study request recommends that CAISO improve the study model to quantify the actual “scheduling” congestion on CAISO’s PACI interface, a component that has not been included in prior cycles<br>• Adding SWIP North relieves certain reliability and economic constraints related to imports across COI. This translates into incremental import capability into CAISO. This increase in incremental import capability should be accounted for estimate of the Capacity Benefits of SWIP North | • The associated market interface issues need to be explored more fully before such benefits can be unilaterally incorporated into transmission capital decisions.<br>• Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes. |

### Conclusion

The economic analysis does not demonstrate sufficient economic benefit to proceed unilaterally as a regional (ISO high voltage) transmission project. Please refer to the separate discussion of COI congestion below.

The ISO therefore considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The scheduling capacity from the Harry Allen end of the ISO’s approved Harry Allen-Eldorado transmission line to Robinson Summit also extends the reach of the overall project to the ISO as well, which creates what appears to be a three-party ITP.

The proposed project has been studied in the informational 50 percent RPS and interregional transmission planning process as set out in chapter 6.

### 4.8.2 Bob SS to Mead Upgrade

**Study request overview**

The study proposal is to upgrade the 15-mile Bob SS to Mead path from its current approximate 400 MVA rating to 800 MVA, 2000 A or greater, by rebuilding the existing line. The project would utilize existing ROW, and could be built within 18 months to 24 months of approval.

**Evaluation**

Please refer to the detailed discussion of Bob SS to Mead congestion and mitigation benefits in section 4.9.3.

### 4.8.3 Mira Loma – Red Bluff 500 kV line

**Study request overview**

The study proposal is to add a new 500 kV transmission line between Red Bluff substation and Mira Loma substation with 50% compensation. Additional transmission reinforcement including reactive support (shunt reactors and capacitors) may be needed at the existing 500 kV substations to properly integrate the proposed project. Furthermore, a new Mira Loma – Red Bluff 500 kV transmission project will also require careful study of the existing SPS and any modifications and readjustments to minimize the use of generation required for tripping under P1 and P6 contingency conditions.

**Evaluation**

Table 4.8-3 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-3: Evaluating study request – Mira Loma – Red Bluff 500 kV Line

| **Study Request: Mira Loma – Red Bluff 500 kV Line** | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Not addressed in submission | • No benefits identified by ISO |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Project can support integration of renewable generation for the ISO. The Cluster 8 Phase 1&2 and Cluster 9 Phase 1 Interconnection Study Report identified several thermal overloads with all facilities in-service. This constraint is commonly referenced as the "West of Devers Area Deliverability Constraint".<br>• Project can integrate higher levels of renewable generation that were curtailed in ISO's 50% RPS "informational only" study, which | • The Desert Area Constraint is due to more generation in the ISO Queue than in the 33% RPS portfolio. Mitigation is addressed through the ISO's generation interconnection process.<br>• 50% RPS portfolios are informational at this time |

| Study Request: Mira Loma – Red Bluff 500 kV Line | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| | indicated high potential for generation curtailment in Riverside County | |
| Local Capacity Area Resource requirements | • Proposed project supports Eastern LA Basin LCR Sub-Area process. The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill – Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,230 MW (source: CAISO TPP 2015-2016), which is to be met by available resources in the Eastern LA Basin sub-area. | • The ISO's preliminary analysis found that although this line may help with the Eastern LA Basin voltage stability issue, reducing the Eastern LA Basin generation also adversely affects the overall LA Basin LCR need. As a result the overall benefits are small compared to the expected cost of the project. |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • See "Delivery of Location Constrained Resource Interconnection Generators" above | • See "Delivery of Location Constrained Resource Interconnection Generators" above |
| Other | • Study request states that the proposed project improve the reliability and thermal overloads of the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista.<br>• Project can eliminate and/or minimize the congestion management cost. Presently, congestion management is used to mitigate thermal issues on the existing West of Devers 230 kV and 500 kV transmission network. Project would reduce the amount of congestion management necessary (including generation curtailments) to alleviate the thermal issue and consequently economic savings could be realized.<br>• Project will minimize continued reliance on the existing Special Protection Systems (SPS), specifically Inland SPS and West of Devers SPS, | • The West of Devers Project will upgrade the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista and will address most if not all of these issues. |

| Study Request: Mira Loma – Red Bluff 500 kV Line | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| | and continued reliance on operating procedures for voltage and thermal control.<br>• Project complements the integration of CAISO approved participating transmission owner's projects and the approved competitive transmission solicitation projects.<br>• Project combats Reactive Power Deficiencies. With the continued load growth and addition of renewable generation in the Eastern area, voltage degradation to the system was observed. The inclusion of the project improved base case voltage issues.<br>• Part of the project's scope is to identify the need for additional voltage support at Red Bluff, Colorado River, and Serrano substations. This analysis will need to be conducted separately to determine an accurate amount of reactive support needed at these existing substations. | |

#### Conclusion

No further assessment was conducted for this submitted study request.

### 4.8.4 Devers – Suncrest 500 kV line

#### Study request overview

The study proposal is to add a new 90 mile 500 kV transmission line originating at the Devers Substation and terminating in the Northern San Diego Area into the Suncrest Substation.

#### Evaluation

Table 4.9-6 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.9-6: Evaluating study request – Devers – Suncrest 500 kV Line

| **Study Request: Devers – Suncrest 500 kV Line** | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Not addressed in submission | • No benefits identified by ISO |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Not addressed in submission | • No benefits identified by ISO |
| Local Capacity Area Resource requirements | • Project proposes to reduced LCR contract costs and production costs<br>• It will reduce the LA Basin and San Diego/Imperial Valley LCR Areas need requirement<br>• The total qualifying capacity1 in the LA Basin in 2026 is projected to be 7,795 MW, which has small margin of only 561 MW (7.8%) above the 7,234 MW LCR need. The total qualifying capacity in the San Diego/Imperial Valley Area is 4,840 MW, which has a small margin of only 191 MW (4.1%) above the 4,649 MW LCR need. Because of the tightening margins in 2026, the Alliance team believes it would be prudent for the CAISO to perform an economic study for these LCR requirements, including both capacity contracts for LCR capacity and the cost of out of merit order dispatch incurred because these resources will be running at times when less expensive energy would be available from outside the LCR Areas. The CAISO should also take into account the cost of curtailment of renewable resources within the CAISO that could be prevented if these LCR resources which are predominantly gas generation would not be required to run by reducing the LCR requirements. | • The LCR requirements in the LA Basin and San Diego have already been reduced by thousands of MWs to address the retirement of SONGS and to address OTC compliance requirements. The approval of the S-Line upgrade will further reduce these requirements. However, the ISO will continue to assess opportunities to further reduce the need for aging gas fired generation in the transmission planning process |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • Not addressed in submission | • No benefits identified by ISO |

| Study Request: Devers – Suncrest 500 kV Line | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Other | • Reduction in curtailment of renewable resources and any future Policy benefits | • This issue can be better assessed once the resource plan has been established |

### Conclusion

No further assessment was conducted for this submitted study request. This proposal may be revisited in the future as noted above.

## 4.8.5 Renewable Energy Express

### Study request overview

The Renewable Energy Express ("REX") transmission project consists of converting a portion of the existing AC Southwest Powerlink (SWPL) to a DC system with terminals at North Gila substation, Imperial Valley substation, and Miguel substation.

### Evaluation

Table 4.8-5 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-5: Evaluating study request – Renewable Energy Express

| Study Request: Renewable Energy Express | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Not addressed in submission | • No benefits identified by ISO |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Project proposes for the ISO to study a scenario that includes the Renewable Express Project and New Mexico wind along with the SunZia transmission project<br>• Project would replace with new New Mexico wind resources, on an energy basis, an equivalent amount of planned California solar PV. It will be necessary to account for the difference in capital costs between California solar PV and New Mexico wind, as well as the difference in economic lives between (i) the 60 year REX and SunZia transmission projects, and (ii) the 20 year lives of rooftop solar PV and wind. New Mexico wind will | • Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes. |

| Study Request: Renewable Energy Express | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| | provide a significant capital cost savings because it takes much less installed New Mexcio wind capacity to provide the same amount of energy as California solar PV. This benefit compounds across the two renewable replacement cycles that are needed to equalize life-time assumptions: once at year 21 and again at year 41. Also, renewable resources can be built at lower cost out-of-state than within California. | |
| Local Capacity Area Resource requirements | • The REX transmission project will provide economic value compared to the reference scenario in terms of (i) reduced production costs, and (ii) lower LCRs within the three LCR areas. | • The ISO's preliminary assessments demonstrated that the local capacity requirement in the San Diego and Imperial Valley subarea would not be significantly reduced by the HVDC project. With the HVDC project modeled, the local capacity requirement continued to be driven either by potential voltage instability in the San Diego area or by contingency flows between the IID and SDG&E systems and would remain at a similar level. Some additional power flow concerns in APS and the San Diego 230 kV systems could also surface. |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • See "Delivery of Location Constrained Resource Interconnection Generators" above | • See "Delivery of Location Constrained Resource Interconnection Generators" above |
| Other | • None | • No benefits identified by ISO |

### Conclusion

No further assessment was conducted for this submitted study request.

The proposed project has been studied in the informational 50 percent RPS and interregional transmission planning process as set out in chapter 6.

### 4.8.6 Round Mountain – Cottonwood 230 kV Project

#### Study request overview

The proposed project installs Smart Wires power flow control devices on the Round Mountain-Cottonwood 230 kV lines.

#### Evaluation

Table 4.8-6 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-6: Evaluating study request – Round Mountain – Cottonwood 230 kV Project

| **Study Request: Round Mountain – Cottonwood 230 kV Project** | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Reduced COI congestion | • The proposed upgrade may mitigate potential overload on the Cottonwood-Round Mountain 230 kV line, hence to increase the limit of corresponding segments of COI nomograms. However, these segments of COI nomograms were not binding constraints in the production simulation therefore the proposed upgrade was not expected to generate sufficient benefit to ISO's ratepayers. |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Not addressed in submission | • No benefits identified by ISO |
| Local Capacity Area Resource requirements | • Not addressed in submission | • No benefits identified by ISO |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • Not addressed in submission | • No benefits identified by ISO |

| Study Request: Round Mountain – Cottonwood 230 kV Project | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Other | • Project was proposed to relieve thermal overloads on the ROUND MT – COTWD_E and ROUND MT – COTWD_E2 230 kV circuits<br>• The proposed project expects to expand the COI - Northern California Hydro nomogram<br>• The proposed project expects to result in a more efficient generation dispatch for CAISO rate payers | • The proposed upgrade may mitigate potential overload on the Cottonwood-Round Mountain 230 kV line, hence to increase the limit of corresponding segments of COI nomograms. However, these segments of COI nomograms were not binding constraints in the production simulation therefore the proposed upgrade was not expected to generate sufficient benefit to ISO's ratepayers. |

### Conclusion

No further assessment was conducted for this submitted study request.

## 4.8.7 SunZia and 1500 MW Wind in New Mexico

### Study request overview

The proposed SunZia Southwest Transmission Project (SunZia) transmission line is a 515-mile, 500kV proposed transmission facility that will deliver primarily wind energy from central New Mexico to markets in California and Arizona. SunZia comprises two single-circuit lines and related substations. SunZia's eastern terminus will be near Corona, NM and its western terminus will be at the Pinal Central substation in the metro Phoenix area. SunZia's first line will be an AC facility and will deliver up to 1,500 megawatts to the ISO scheduling point at the Palo Verde Nuclear Power Project hub, with firm transmission rights on the existing metro-Phoenix transmission system.

### Evaluation

Table 4.8-7 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-7: Evaluating study request – SunZia and 1500 MW Wind in New Mexico

| Study Request: SunZia and 1500 MW Wind in New Mexico | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Not addressed in submission | • No benefits identified by ISO |

| Study Request: SunZia and 1500 MW Wind in New Mexico | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Not addressed in submission | • No benefits identified by ISO |
| Local Capacity Area Resource requirements | • Not addressed in submission | • No benefits identified by ISO |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • Not addressed in submission | • No benefits identified by ISO |
| Other | • Production cost benefits (savings) for California customers based on New Mexico wind energy replacing an equivalent amount of solar energy<br>• Contribution to Flex RA from New Mexico wind energy by providing morning down-ramp and late afternoon/early evening up-ramp renewable energy resources.<br>• Potential contribution to Flex RA from flexible gas-fired generation in Arizona and/or New Mexico that can readily interconnect with SunZia.<br>• RA benefits (relative to other wind sources) from high-capacity factor New Mexico wind (i.e., location-specific RA)<br>• Ability to export excess California solar energy to eastern Arizona and New Mexico.<br>• Opportunity to facilitate expansion of CAISO footprint to New Mexico.<br>• Contribution to achieving CA RPS and GHG goals because New Mexico wind is complimentary to California solar from different time-of-day and seasonal production profiles | • Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes. |

#### Conclusion

No further assessment was conducted for this submitted study request.

The proposed project has been studied in the informational 50 percent RPS and interregional transmission planning process as set out in chapter 6.

### 4.8.8 LCR Benefit Evaluation: South Bay-Moss Landing, Wilson, LA Basin, San Diego/Imperial Valley

#### Study request overview

The study request recommends the ISO includes studies of the cost of congestion into the LCR requirement load areas, especially in areas with significant LCR requirements with high ratios of LCR requirements compared to the area's Net Qualifying Capacity ("NQC") such as the South Bay – Moss Landing, Wilson (Fresno), LA Basin, and San Diego/Imperial Valley.

#### Evaluation

Table 4.8-8 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-8: LCR Benefit Evaluation – South Bay-Moss Landing, Wilson, LA Basin, San Diego/Imperial Valley

| **Study Request: LCR Benefit Evaluation: South Bay-Moss Landing, Wilson, LA Basin, San Diego/Imperial Valley** | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Identified Congestion | • Not addressed in submission | • No benefits identified by ISO |
| Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators | • Not addressed in submission | • No benefits identified by ISO |

| Study Request: LCR Benefit Evaluation: South Bay-Moss Landing, Wilson, LA Basin, San Diego/Imperial Valley | | |
|---|---|---|
| **Benefits category** | **Benefits stated in submission** | **ISO evaluation** |
| Local Capacity Area Resource requirements | • Request is for CAISO to evaluate the following LCR areas requirements to determine the extent of transmission congestion. This evaluation should Include: (1) the cost of the LCR capacity contracts; and, (2) the cost of utilizing potentially higher cost generation running inside the LCR area instead of importing less expensive energy from outside the load area<br>◦ South Bay – Moss Landing<br>◦ Wilson (Fresno)<br>◦ LA Basin<br>◦ San Diego/Imperial Valley | • The ISO will continue to assess opportunities to further reduce the need for aging gas fired generation in future transmission planning processes. Upgrades to reduce San Diego/Imperial Valley area local capacity requirements are discussed in section 4.9.1 and the South Bay-Moss Landing sub-area is discussed in section 4.9.4. |
| Increase in Identified Congestion | • Not addressed in submission | • Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process |
| Integrate New Generation Resources or Loads | • Not addressed in submission | • No benefits identified by ISO |
| Other | • Not addressed in submission | • No benefits identified by ISO |

### Conclusion

The S-Line Upgrade to reduce local capacity requirements in the San Diego/Imperial Valley combined area is discussed in section 4.9.1 and the South Bay-Moss Landing sub-area is discussed in section 4.9.4. No further assessments were conducted for other areas identified this submitted study request.

## 4.9 Detailed Investigation of Congestion and Economic Benefit Assessment

After evaluating identified congestion and reviewing stakeholders' study requests, consistent with tariff section 24.3.4.2, the ISO selected three congested branch groups for further assessment, which are listed in Table 4.9-1.

Table 4.9-1: Detailed Congestion Investigation

| Congestion area or branch group | Location and facilities | Direction |
|---|---|---|
| IID 230 kV S-Line | Between IID's El Centro and ISO's SDGE Imperial Valley 230 kV substations | From IID to ISO |
| Bob SS-Mead S 230 kV line | Between ISO's VEA new Bob switching station and WAPA's Mead substation | From Bob to Mead |
| San Diego North | ISO's SDGE Melrose Tap to San Marcos 69 kV line, and Encina Tap to San Luis Rey 230 kV line | From south to north |

This study step consists of conducting detailed investigation and modeling enhancements as needed. Based on the detailed study results, it is decided whether economic assessment for potential network upgrades is needed. If the need is identified, then this study step evaluates the production benefits of potential network upgrades based on TEAM methodology. In the benefit assessments, ISO ratepayer's benefits and WECC society benefits are calculated as:

- *ISO ratepayer's production benefit = (ISO Net Payment of the pre-upgrade case) – (the ISO Net Payment of the post-upgrade case)*
- *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*
- *ISO Net Payment = ISO load payment – ISO owned generation profit – ISO owned transmission revenue*

All costs and payments provided in this section are in 2016 US dollars.

In addition to the production benefit, other benefits may be also evaluated as needed.

As discussed in section 4.1, other benefits are also taken into account on a case by case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. The potential economic benefits are quantified as reductions of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[90]

In this 2017-2018 planning cycle, two study areas were identified as needing additional consideration based on local capacity benefits:

- Consideration of a proposed upgrade to alleviate thermal limitations on the IID-owned 230 kV S-Line was triggered by collaborative discussions between the ISO and IID, with the ISO focus being on reducing local capacity needs driven up by the thermal limitations on this neighboring parallel system as well as potential congestion benefits. (Note that this was also identified through the production simulation benefits review.)

- A focus on reducing local capacity needs in the South Bay-Moss Landing area, which was triggered by increasing local reliability must-run obligations in the area and industry concern with the need for RMR agreements. This emphasis was highlighted by the CPUC's adoption of Resolution E-4909 authorizing PG&E to hold competitive solicitations for energy storage and/or preferred resources to meet specific local area needs in this area as well as others.

As a result, four areas were ultimately selected for detailed investigation:

- IID 230 kV S-Line congestion and capacity benefits

- Bob SS-Mead S 230 kV line congestion benefits

- San Diego North congestion benefits

- South Bay-Moss Landing Sub-area local capacity requirements

### 4.9.1 IID 230 kV S-Line congestion and capacity benefits

The ISO and IID examined upgrades to IID's existing S-line as a mitigation to existing S-Line thermal constraints. The S-Line is an 18.1 mile, 230 kV single circuit wood pole construction line owned by IID running from IID's El Centro substation to SDG&E's Imperial Valley substation.

The project would consist of the ISO - through a participating transmission owner – funding the upgrade of the existing wood pole line to 230 kV double circuit steel tower construction, and the necessary upgrades to termination equipment, in return for entitlements to the incremental transmission capacity created by the upgrade. As the project consists of upgrades to both IID's existing transmission line and the SDG&E-owned Imperial Valley substation, it is anticipated that SDG&E would fund the IID upgrades and retain the rights to the incremental transmission capacity. A preliminary target date of 2021 has been established, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The upgrades were recognized as providing economic benefits to the ISO by alleviating limitations on the use of the ISO system caused by parallel flows (loop flows) identified in previous planning

[90] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

study results, reducing local capacity needs materially in the combined San Diego - Imperial Valley areas as well as reducing market congestion on the ISO system - which totaled $6 million in 2015 and 2016. As set out below, the estimated production simulation results yielded an annual benefit of 2.82 million, with a present value of $40 million, and a present value of estimated local capacity benefits of $111.3 to 222.6 million. In addition to the above economic benefits, there is added benefit of removing a limitation to increased deliverability from the Imperial area, and IID in particular.

S-Line Congestion Benefits

Congestion on this inter-tie between IID's El Centro substation and SDG&E's Imperial Valley substation was observed in the simulation results under the N. Gila – Imperial Valley 500 kV N-1 contingency, with flow direction from IID to the ISO.

A mitigation of upgrading the S-Line from its existing single circuit wood pole construction to a double circuit tower construction with each circuit rated at 786 MVA[91] was studied in production cost simulation, and its production benefit was assessed based on TEAM methodology. The simulation results showed that the S-Line congestion can be completely mitigated with the double circuit upgrade. Table 4.9-2 showed the TEAM analysis results for this upgrade.

4.9-2: TEAM analysis for S-Line double circuit upgrade

| | **Pre S-Line upgrade ($M)** | **Post S-Line upgrade ($M)** | **Savings ($M)** |
|---|---|---|---|
| ISO load payment | 7,575.95 | 7,602.79 | |
| ISO owned generation profits | 3,909.36 | 3,935.32 | |
| ISO owned transmission revenue | 178.66 | 182.37 | |
| **ISO Net payment** | **3,487.92** | **3,485.10** | **2.82** |
| **WECC Production cost** | **18,836.17** | **18,837.07** | **-0.90** |

ISO ratepayer's benefit was determined to be $2.82 million. The present value of this savings over the 50 year life of the project at a 7% discount rate is approximately $40 million.

Local Capacity Benefits:

The primary and most immediate benefit to ISO ratepayers is a reduction in local capacity requirement in the San Diego-Imperial Valley area.

The 2018 local capacity requirement for the San Diego-Imperial Valley Area is driven by the loss of the TDM combined cycle power plant, system readjusted, followed by the loss of the Imperial Valley-North Gila 500 kV line. This contingency would result in overloading the Imperial Valley-

91 This project design was provided by IID for use in the ISO's generation interconnection studies in 2014.

El Centro 230 kV S-Line unless sufficient local generation capacity is available. With the S-Line upgrade project in-service the local capacity requirement can be reduced by approximately 213 MW, at which point the contingency described above begins to result in overloading the El Centro #4 230/92 kV transformer. Removing that constraint would bring the total benefits up higher, potentially to 500 MW. Thus, the upgrade provides immediate benefits and positions the system for further reductions in the future.

The price of San Diego area generation capacity in 2018 based on the Capacity Procurement Mechanism (CPM) price set out in the ISO tariff is the applicable monthly soft offer cap of $6.31/kw-month. This results in a $75,720/MW-Year price for this capacity. The full value can be used as an estimate of the high end of the range of benefit provided by a reduction in local capacity requirement. Recognizing that local capacity in the San Diego-Imperial Valley area could also provide other benefits such as flexible generation, a reasonable low end of the benefit is half of the local capacity price, or about $37,860/MW-Year.

Applying this range to a 213 MW local capacity reduction results in a range of annual local capacity benefits of $8.1 million to $16.2 million. The present value of that annual revenue stream over 50 years, consistent with the derivation of the total cost-to-capital ratio of 1.45, is $111.3 million to $222.6 million.

<u>Cost estimates:</u>

The current estimate from IID for upgrades to the transmission line plus the cost of upgrading termination equipment is below the $50 million. The current estimate from IID is $32 million, and while a cost estimate is not yet available for the Imperial Valley termination, the ISO notes that the cost estimate for a two breaker line termination is approximately $10 million as provided in SDG&E's 2017 per unit cost guide information available through the ISO's generation interconnection process. For purposes of economic valuation, recognizing the preliminary nature of the cost estimates, the cost-benefit considerations have been based on a $50 million estimate.

Applying the ISO's screening factor of 1.45 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $50 million capital translates to a total cost of $72.5 million.

<u>Benefit to Cost Ratio</u>

Summing the production simulation benefits described above of $40 million to the low end of the capacity benefits $111.3 million yields total benefits of $151.3 million.

Applying this low end of the benefits range to the conservatively high cost estimate of $72.5 million provides a benefit to cost ratio of approximately 2.08.

<u>Other Alternatives:</u>

The ISO has also considered qualitatively other alternatives to this upgrade in the past. These have included flow controllers such as back-to-back HVDC converters, or phase shifting transformers, as well as the much broader-scoped Renewable Energy Express project proposed in this planning cycle.

The upgrade to the 230 kV S-Line is considered to be the lowest cost and least complex solution. It also provides a basis for future opportunities for cost savings and access to potential renewable resources in the near term with the least dependence on continuous coordination of operation and control with neighboring systems, and the least risk of under-sizing the project for future needs.

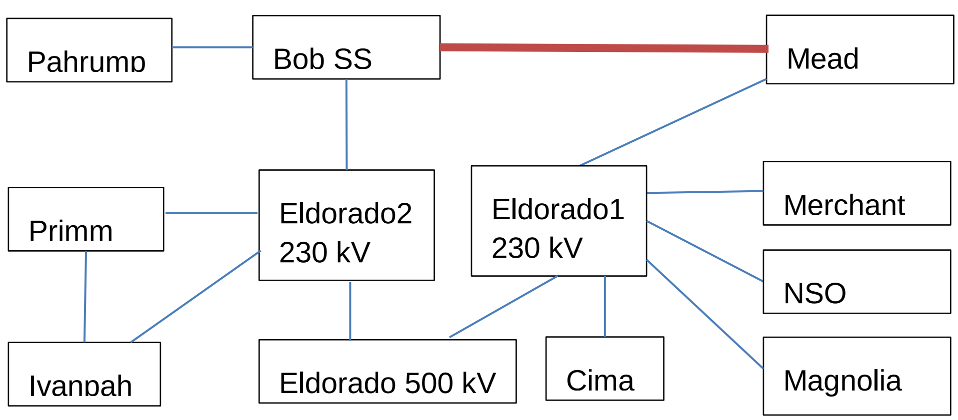
Accordingly, the S-Line upgrade has been found to be needed as an economic-driven project.

### 4.9.2 Bob SS - Mead S 230 kV line congestion benefits

The Bob SS to Mead S 230 kV line is an inter-tie between ISO's VEA system and the WAPA system. The Bob switching station is a part of a transmission project to build a new 230 kV line from Eldorado to the new Bob switching station and to loop the existing Pahrump to Mead S 230 kV line into Bob SS. Congestion on the Bob SS to Mead S 230 kV line was observed in the production simulation results in the direction from Bob SS to Mead S under normal conditions. Figure 4.9-1 illustrates the topology in this area.

A mitigation of rebuilding the Bob SS to Mead S 230 kV line to increase the rating to 724 MVA - as described in section 4.8.2 and as first proposed by VEA in a generation interconnection study in 2017 - was studied in production cost simulation, and its production benefit was assessed based on TEAM methodology. The simulation results showed that the congestion can be completely mitigated with the upgrade. The TEAM analysis results for this upgrade are set out in Table 4.9-3.

Figure 4.9-1 Transmission topology around Bob SS to Mead S 230 kV line



4.9-3: TEAM analysis for Bob SS-Mead S 230 kV upgrade in base case study

| | Pre Bob SS-Mead S upgrade ($M) | Post Bob SS-Mead S upgrade ($M) | Savings ($M) |
|---|---|---|---|
| ISO load payment | 7,602.79 | 7,576.60 | |
| ISO owned generation profit | 3,935.32 | 3,985.82 | |
| ISO owned transmission revenue | 182.37 | 118.78 | |
| **ISO Net payment** | **3,485.10** | **3,472.00** | **13.10** |
| **WECC Production cost** | **18,837.07** | **18,818.19** | **18.88** |

The ISO ratepayer's benefit was found to be $13.10 million. The present value of this savings over the 40 year life of the project at a 7% discount rate is approximately $180 million. Production stimulation results also showed that the total ISO renewable curtailment was reduced by about 72 GWh with the Bob SS to Mead S upgrade. Note that as the S-Line upgrade discussed in section 4.9.1 was driven by primarily local capacity benefits with production benefits being secondary, the S-Line upgrade to double circuit tower construction was modeled in this Bob SS to Mead S study.

The capital cost of upgrade Bob SS-Mead S 230 kV line is approximately $25 million as estimated in the study request submitted by GridLiance. Applying the ISO's screening factor of 1.45 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $25 million capital translates to a total cost of $37 million. The production benefit identified in this study is sufficient to justify the upgrade as an economic-driven project. GridLiance estimated the in-service date of the Bob SS to Mead S 230 kV line upgrade to be approximately 18~24 months after the project is approved, according to the study request submitted by GridLiance.

Accordingly, the Bob SS-Mead S 230 kV line upgrade has been found to be needed as an economic-driven project.

In addition to the base case study, a sensitivity scenario was also studied as described below.

**Sensitivity scenario: No export limit for the ISO system**

In the base case database, 2000 MW net export limit was enforced for the ISO system. This limit contributed to renewable curtailment in the simulation. Since the Bob SS-Mead S congestion is highly related to ISO's export and renewable curtailment, the export limit was removed in this sensitivity scenario. The same assessment was conducted and the ISO ratepayer benefit was $8.17 million. The present value is approximately $112 million, which is still greater than the total cost of $37 million. The production simulation results were shown in Table 4.9-4.

4.9-4: TEAM analysis for Bob SS-Mead S 230 kV upgrade in No Export Limit sensitivity study

| | Pre Bob SS-Mead S upgrade ($M) | Post Bob SS-Mead S upgrade ($M) | Savings ($M) |
|---|---|---|---|
| ISO load payment | 8,010.32 | 7,993.65 | |
| ISO owned generation profits | 4,202.71 | 4,320.77 | |
| ISO owned transmission revenue | 356.07 | 229.52 | |
| **ISO Net payment** | **3,451.53** | **3,443.36** | **8.17** |
| **WECC Production cost** | **18,691.89** | **18,659.76** | **32.13** |

### 4.9.3 San Diego North congestion benefits

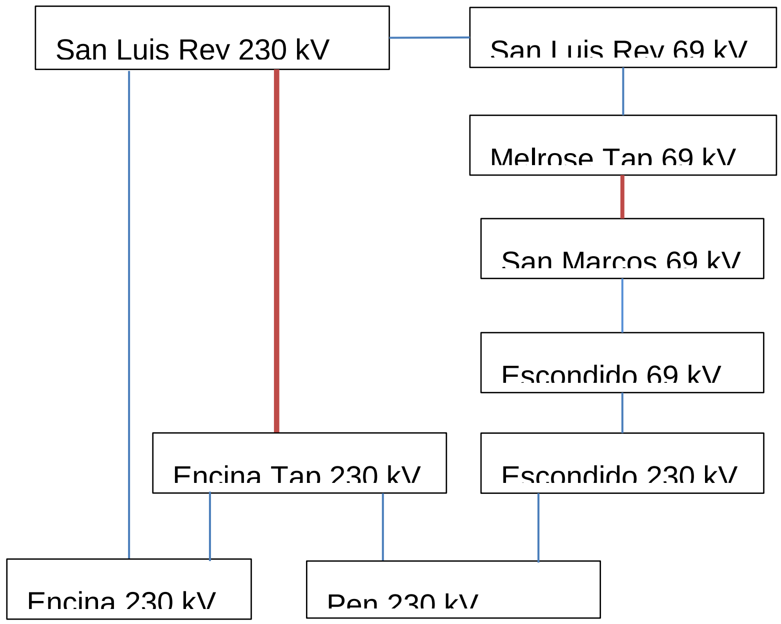
San Diego North area congestion was observed in this planning cycle, as set out in Table 4.9-6.

4.9-6: San Diego North Congestion

| Constraints Name | Costs_F (000 $) | Duration_F (Hrs) | Costs_B (000 $) | Duration_B (Hrs) | Costs_T (000 $) | Duration_T (Hrs) |
|---|---|---|---|---|---|---|
| MELRSETP-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV | 0 | 0 | 142 | 56 | 142 | 56 |
| ENCINATP-SANLUSRY 230 kV line, subject to SDGE N-1 EN-SLR 230 kV | 39 | 10 | 0 | 0 | 39 | 10 |

These congestions were observed in correlation with high flows from south to north on the Encina to San Luis Rey corridor. The congestion on the Melrose Tap to San Marcos 69 kV line was observed on the direction from San Marcos to Melrose Tap and under the N-2 contingency of losing the Encina to San Luis Rey 230 kV line and the Pen to Encina Tap to San Luis Rey 230 kV line. As the 69 kV system and the 230 kV system in this corridor are looped, flows are pushed to the 69 kV system when the 230 kV path is lost. The Encina Tap to San Luis Rey 230 kV line can be congested in the direction from the Encina Tap to San Luis Rey under the N-1 contingency of losing the Encina to San Luis Rey 230 kV line. Figure 4.9-2 illustrates the loop between the 230 kV system and the 69 kV system in this area. The congested lines are highlighted with red.

Figure 4.9-2 Transmission topology around Encina-San Luis Rey area




Two potential mitigations were studied in this planning cycle. One is to build the second Encina to San Luis Rey 230 kV line and de-loop the Pen to San Luis Rey 230 kV line from the Encina Tap. The other is an SPS solution that includes tripping generators at Carlsbad, Palomar, and Otay Mesa under N-1 and N-2 contingencies of the 230 kV lines, and open the 69 kV loop at Melrose to San Marcos under the N-2 contingency of the 230 kV lines.

Similar to the Bob SS to Mead S study discussed above, the S-Line upgrade was modeled in the base case study.

The base case results are provided in Table 4.9-7 and Table 4.9-8.

4.9-7: TEAM analysis for Encina to San Luis Rey upgrade with adding a new line

| | **Pre Encina-San Luis Rey new line upgrade ($M)** | **Post Encina-San Luis Rey new line upgrade ($M)** | **Savings ($M)** |
|---|---|---|---|
| ISO load payment | 7,602.79 | 7599.91 | |
| ISO owned generation profits | 3,935.32 | 3936.56 | |
| ISO owned transmission revenue | 182.37 | 180.18 | |
| **ISO Net payment** | **3,485.10** | **3483.17** | **1.93** |
| **WECC Production cost** | **18,837.07** | **18,839.01** | **-1.94** |

4.9-7: TEAM analysis for San Diego North SPS solution

| | Pre SPS solution ($M) | Post SPS solution ($M) | Savings ($M) |
|---|---|---|---|
| ISO load payment | 7,602.79 | 7,595.01 | |
| ISO owned generation profits | 3,935.32 | 3,927.15 | |
| ISO owned transmission revenue | 182.37 | 180.59 | |
| **ISO Net payment** | **3,485.10** | **3,487.28** | **-2.18** |
| **WECC Production cost** | **18,837.07** | **18,839.01** | **-1.94** |

The new Encina to San Luis Rey line solution can generate a $1.93 million benefit for ISO ratepayers, which translates to a present value of $27 million approximately assuming a 50 year life of the project and a 7% discount rate.

The simulation results showed that the SPS solution can completely mitigate the congestions in this area and did not cause any unserved load. However, the SPS solution did not provide production benefit to ISO ratepayers. The SPS solution may be a valid option to consider in future planning cycles if it can eliminate potential reliability violations that may evolve in the future in this local area.

The capital cost estimated by SDG&E for the new Encina to San Luis Rey 230 kV line solution was $70 million ~ $80 million. Applying the ISO's screening factor of 1.45 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the capital cost of $70 million ~ $80 million translates to a total cost of $101 million ~ $116 million. The production benefit of the new Encina to San Luis Rey 230 kV line solution was not sufficient to provide economic justification, and the solution was not found to be needed.

Some factors may impact San Diego North congestion and the corresponding economic benefit assessment in the future, such as higher RPS goals and the gas-fired generators retirement. Therefore, the ISO will continue to monitor the congestion in this area in future planning cycles.

### 4.9.4 South Bay-Moss Landing Sub-area Local Capacity Requirements

The South Bay-Moss Landing sub-area is a part of the Greater Bay Area local capacity requirement (LCR) area.

Resource Adequacy procurement shortfalls in this sub-area for 2018 has triggered the need for the ISO to invoke backstop procurement for two natural gas plants located in this sub-area. On November 2, 2017, the ISO Board of Governors approved the designation of Calpine's 602 MW Metcalf Energy Center as a reliability must-run resource for 2018, given local area needs and Calpine's indication that the resource would be unavailable absent a capacity contract[92]. On December 22, 2017, the ISO issued a Capacity Procurement Mechanism designation for Dynegy's 510 MW Moss Landing Unit 2 due to a deficiency in the 2018 Resource Adequacy showings for this sub-area.

The sub-area local capacity requirement was determined to be 2,221 MW in the 2018 LCR technical study[93] and 2,346 MW in the 2022 LCR technical study[94]. At the time the LCR studies were conducted by the ISO there was 2,408 MW of generation located within the LCR area. The ISO undertook an assessment and found that the Metcalf Energy Center was required to meet the 2018 local capacity requirement in the South Bay-Moss Landing sub-area and sought ISO Board of Governor's approval designation of the Metcalf Energy Center as reliability must-run resources. The ISO further committed to working with PG&E to incorporate energy storage, preferred resources, and transmission upgrades to achieve an overall comprehensive and economic solution to these local needs recognizing that a longer term plan is needed regarding local capacity requirements in the area as well as examining potential short term mitigations.[95]

The CPM designation was issued to Moss Landing 2 based on the ISO's technical analysis, including power flow studies, assessing the effectiveness of the resources reflected in the annual Resource Adequacy Plan submissions. This analysis led to the determination that there were material deficiencies necessitating the designation.

While a broader analysis of a comprehensive plan for reducing reliance on gas-fired generation in this and other local capacity areas will be undertaken in future planning cycles, the ISO continued to assess potential shorter term mitigations for the South Bay-Moss Landing sub-area requirements in this 2017-2018 transmission planning process.

<u>2017-2018 transmission plan analysis:</u>

The assessment in the 2017-2018 planning cycle considered the potential for more immediate reductions in local capacity.

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[92] In its June 2, 2017 letter to the ISO[92], Calpine Corporation indicated its intention to remove the Metcalf Energy Center from the relevant Participating Generator Agreement(s), making it unavailable for ISO dispatch effective January 1, 2018. The Metcalf Energy Center is located within the South Bay-Moss Landing sub-area.

[93] http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf

[94] http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf

[95] Subsequent to those events, the CPUC adopted Resolution E-4909 on January 11, 2018, authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability, focusing on this area and other new reliability must-run designations that took place in 2017.

The most limiting condition that established the South Bay-Moss Landing sub-area local capacity requirement is the overloading of the Moss Landing-Los Aguilas 230 kV line for the P6 contingency of the Tesla-Metcalf 500 kV and the Moss Landing-Los Banos 500 kV lines. This is a part of the southern path flow into the South Bay-Moss Landing sub-area.

The next most limiting condition of the South Bay-Moss Landing sub-area local capacity requirement is the overload of the Trimble-San Jose 'B' 115 kV line for the same P6 contingency of the Tesla-Metcalf 500 kV and the Moss Landing-Los Banos 500 kV lines.

Consistent with the ISO's planning process as set out in section 1.2, the assessment took into account the results of the reliability analysis set out in chapter 2 and Appendix B regarding projects that are being advanced or re-scoped through the identification of reliability-driven requirements before considering policy-driven or economic-driven enhancements. More specifically, the assessment took into account the following projects and modifications to projects set out in section 2.5.5 and Appendix B2.5 that are being recommended as reliability-driven upgrades and that have an impact on the South Bay-Moss Landing sub-area local capacity requirement:

- Re-scoping of the South of San Mateo Capacity Increase
    - In particular, the closing of the currently Normal Open points on the Monta Vista-AMES 115 kV path. This is anticipated to be completed within 2018.
- San Jose-Trimble 115 kV Line Limiting Facility Upgrade
    - The upgrade of the limiting substation equipment to achieve the full capacity of the San Jose-Trimble 115 kV line of 189 MVA. The project is estimated to be in-service by December 2018.

Note that if these projects were not already recommended for approval as reliability-driven projects for other reasons, the ISO expects they would have been found needed as part of this economic-driven assessment.

The assessment also took into account updated information from PG&E.

In the course of this assessment, PG&E updated the line rating of the Moss Landing-Los Aguilas 230 kV line in the PG&E base cases used in the 2018 local capacity requirement technical studies and the transmission planning process reliability assessment from 318 MVA to 339 MVA.

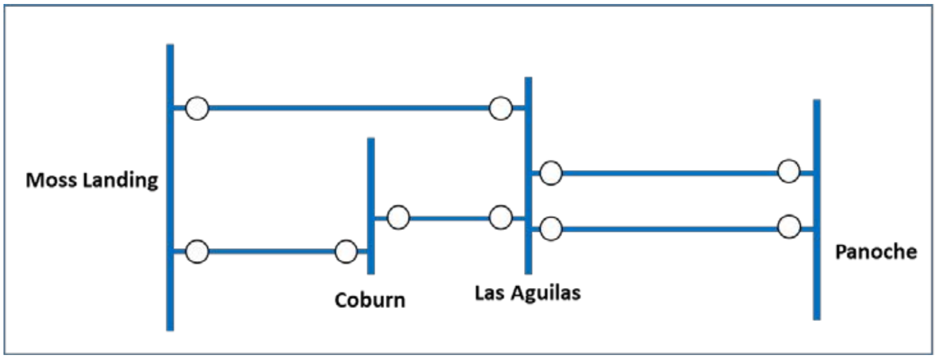
In addition in December 2017, PG&E identified to the ISO the possibility of rerating the Moss Landing-Los Aguilas 230 kV lines beyond the existing ratings up to 400 MVA. The current line rating by PG&E is based upon a 2ft/s wind speed assumption. PG&E has indicated to the ISO that through their assessment of the line rating it could use a 4ft/s wind speed assumption similar to other lines that have been rerated on the PG&E system.

Considering the above parameters, the ISO then considered what additional requirements would be necessary to materially reduce the local capacity requirement in the South Bay-Moss Landing sub-area.

*Moss Landing–Panoche 230 kV Path Upgrade*

The South Bay-Moss Landing sub-area is connected to the Fresno area through a double circuit 230 kV line between the Moss Landing and Panoche substations with interconnections to the Los Aguilas and Coburn substations as shown in Figure 4.10-1.

Figure 4.9-1: Moss Landing-Panoche 230 kV Path



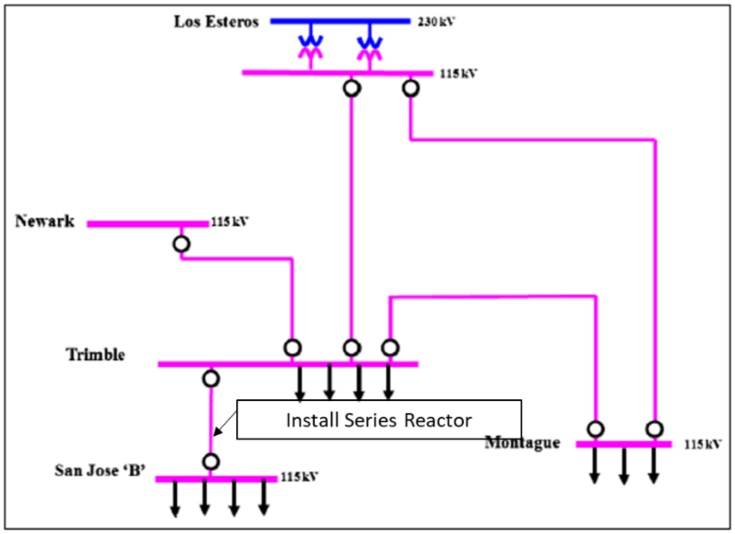

As indicated above, the existing emergency rating of the Moss Landing-Las Aguilas 230 kV line and the Las Aguilas-Panoche #1 230 kV line is 339 MVA. The Moss Landing-Coburn 230 kV line and the Coburn-Las Aguilas 230 kV lines are rated at 318 MVA due to terminal equipment limitations associated with the current transformers (CT) at Coburn substation. The Las Aguilas-Panoche #2 230 kV line is rated at 318 MVA due to terminal equipment limitations associated with the wavetraps at Panoche substation. To achieve the rerate of the lines to 400 MVA as indicated above for the Moss Landing-Panoche 230 kV Path, terminal equipment upgrades at Coburn and Panoche are required. The cost estimate to rerate the 230 kV lines and upgrade the terminal equipment is $5 million dollars with an expected in-service date of December 2018.

With the mitigation plans identified above for the Moss Landing-Las Aguilas constraints, the Trimble-San Jose ‘B’ 115 kV overload would be the limiting condition to establish the South Bay-Moss Landing sub-area local capacity requirement.

*San Jose-Trimble 115 kV line limitation and consideration of series reactors*

As noted above, the San Jose-Trimble 115 kV line is also identified as a limiting facility for establishing local capacity requirements for the South Bay-Moss Landing sub-area. The ISO assessed the size of series reactor necessary to alleviate the potential thermal overloading of this circuit, and found that under the most limiting P6 contingency, a 4 ohm series reactor would be sufficient.

Figure 4.9-2: San Jose-Trimble 115 kV Series Reactors




Based on the per unit cost calculated from Request Window submissions for similar projects, the estimated cost for the addition of this series reactor is expected to be between $6M to $9M and the expected in-service date is May, 2019.

In the event that the project is not in-service by the expected in-service date, operational action plans during abnormal operating conditions can be implemented as a temporary mitigation plan to mitigate the overloads in the interim until the series reactor is in-service.

Summary of results:

The two economic-driven projects comprising the South Bay-Moss Landing enhancements, having a combined capital cost of $14 million and local capacity reduction benefit of over 400 MW, are found to be needed. The ISO also supports the rerating of transmission lines and interim operating procedures discussed in this section.

The combination of the modeling changes, proposed line rerating, recommended reliability-driven projects, and the two economic-driven projects collectively reduce the local capacity requirements for the South Bay-Moss Landing sub-area by approximately 400 to 600 MW beginning in 2019[96]
:

- Rerate the Moss Landing-Los Aguilas 230 kV lines to 400 MVA. (PG&E action)
- Re-scoping of the South of San Mateo Capacity Increase (reliability-driven project found to be needed in this 2017-2018 transmission plan)
- San Jose-Trimble 115 kV Line Limiting Facility Upgrade (reliability-driven project found to be needed in this 2017-2018 transmission plan)

[96] Since several of the identified upgrades will not be in effect until the end of 2018 or early 2019, the identified RMR need for the Metcalf Energy Center in 2018 as well as the need for the CPM designation for Moss Landing 2 remain valid.

- Moss Landing–Panoche 230 kV Path Upgrade (economic-driven project found to be needed in this 2017-2018 transmission plan)
- San Jose-Trimble 115 kV Series Reactor (economic-driven project found to be needed in this 2017-2018 transmission plan)
- Interim operating procedures to mitigate delay of San Jose-Trimble 115 kV Series Reactor if delays occur (PG&E action)

## 4.10 Summary and Recommendations

The production cost simulation was conducted in this economic planning study and grid congestion was identified and evaluated. Detailed congestion investigation and production benefit assessment were conducted for the selected congestions that showed as potential economically-driven projects because of either recurring congestion, high congestion cost, or relatively low capital cost of potential mitigations. Other benefits, particularly local capacity benefits, were assessed for two study areas. Table 4.11-1 summarized the overall economic planning study results in 2017~2018 planning cycle.

Table 4.10-1 Summary of economic assessment in 2017-2018 planning cycle

| **Congestion or study area** | **Production benefit ($M)** | **Capacity benefit ($M)** | **Estimated total cost ($M)** | **Economic justification** |
|---|---|---|---|---|
| S-Line | 40 | 85~110 | 46~72 | Yes |
| Bob SS-Mead S | 180 | Not applicable | 37 | Yes |
| San Diego North | 27 | Not applicable | 101~116 | No |
| South Bay-Moss Landing area | Not applicable | 400-600 MW LCR benefit | $14 | Yes |

In summary, four upgrades[97] were found to be needed as economic-driven projects in the 2017-2018 planning cycle. They are the S-Line Upgrade, the Bob SS to Mead S 230 kV Line Upgrade, and the South Bay-Moss Landing enhancements comprising of the San Jose-Trimble 115 kV series reactor and the Moss Landing–Panoche 230 kV Path Upgrade.

Several paths and related projects will be monitored in future planning cycles to take into account improved hydro modeling, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals.

[97] The Moorpark-Pardee 4th Circuit found to be needed in this transmission plan can also be considered an economic-driven project, but has been included as part of the more comprehensive reliability-driven requirements discussion set out in chapter 2 for the Moorpark Sub-area. Section 24.4.6.7 of the ISO tariff states: *"…the CAISO will conduct the High Priority Economic Planning Studies selected under Section 24.3.4 and any other studies that the CAISO concludes are necessary to determine whether additional transmission solutions are necessary to address: …(b) Local Capacity Area Resource requirements;"*

# Chapter 5

# 5 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are either set out in the ISO tariff or forming part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy studies, both short term and long term, and the long-term congestion revenue rights (LT CRR) simultaneous feasibility test studies.

## 5.1 Reliability Requirement for Resource Adequacy

Section 5.1.1 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 as well as additional analysis supporting long term planning processes, being the local capacity technical analysis and the resource adequacy import allocation study. 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 2018. Upgrades that are being recommended for approval in this transmission plan have therefore not been taken into account in these studies.

### 5.1.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2017. A short-term analysis was conducted for the 2018 system configuration to determine the minimum local capacity requirements for the 2018 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on May 1, 2017.

For detailed information on the 2018 LCR Report please visit:
http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2022 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively.

The 2022 LCR Report was published on May 3, 2017 and for detailed information please visit:

http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf

The ten-year LCR studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide indication whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and per agreement between agencies they are done on every other year cycle. The most recent ten-year LCR study was prepared in last year's 2016-2017 transmission planning process.

For detailed information about the 2026 long-term LCT study results, please refer to the stand-alone report in the Appendix D of the 2016-2017 Transmission Plan.

As shown in the LCT reports and indicated in the LCT manual, 11 load pockets are located throughout the ISO-controlled grid as shown in and illustrated in Table 5.1-1 and Figure 5.1-1.

Table 5.1-1: List of LCR areas and the corresponding PTO service territories within the ISO Balancing Authority Area

| No | LCR Area | PTO Service Territory |
|---|---|---|
| 1 | Humboldt | PG&E |
| 2 | North Coast/North Bay | |
| 3 | Sierra | |
| 4 | Stockton | |
| 5 | Greater Bay Area | |
| 6 | Greater Fresno | |
| 7 | Kern | |
| 8 | Los Angeles Basin | SCE |
| 9 | Big Creek/Ventura | |
| 10 | Greater San Diego/Imperial Valley | SDG&E |
| 11 | Valley Electric | VEA |

Figure 5.1-1: 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 160 MW. In contrast, the requirements of the Los Angeles Basin are approximately 8,000 MW. The short- and long-term LCR needs from this year's studies are shown in Table 5.1-2.

Table 5.1-2: Local capacity areas and requirements for 2018, 2022 and 2026

| **LCR Area** | **LCR Capacity Need (MW)** | | |
|---|---|---|---|
| | **2018** | **2022** | **2026** |
| Humboldt | 169 | 169 | 171 |
| North Coast/North Bay | 634 | 440 | 547 |
| Sierra | 2,113 | 1,967 | 1,004 |
| Stockton | 719 | 702 | 516 |
| Greater Bay Area | 5,160 | 5,315 | 5,732 |
| Greater Fresno | 2,081 | 1,860 | 1,474 |
| Kern | 453 | 123 | 392 |
| Los Angeles Basin | 7,525 | 6,022 | 7,234 |
| Big Creek/Ventura | 2,321 | 2,597 | 2,528 |
| Greater San Diego/Imperial Valley | 4,032 | 4,643 | 4,649 |
| Valley Electric | 0 | 0 | 0 |
| **Total** | **25,207** | **23,838** | **24,247** |

Notes:

1) For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.[98]
2) For more information about the 2018 LCT study results, please refer to the report posted on the ISO website.
3) For more information about the 2022 LCT study results, please refer to the report posted on the ISO website.
4) For more information about the 2026 LCT study results, please refer to the Appendix D of the 2016-2017 Transmission Plan.

### 5.1.2 Resource adequacy import capability

The ISO has established the maximum RA import capability to be used in year 2018 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[99]. The entire import allocation process[100] is posted on the ISO website.

The ISO also confirms that all import branch groups or sum of branch groups have enough maximum import capability (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 2027.

[98] "Final Manual 2018 Local Capacity Area Technical Study," December 2016, http://www.caiso.com/Documents/2018LocalCapacityRequirementsFinalStudyManual.pdf.

[99] "California ISO Maximum RA Import Capability for year 2018," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2018.pdf.

[100] *See* general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2017-2026.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2021 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The 10-year increase in MIC from current levels out of 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, and, for the ISO system, on the West of Devers upgrades in particular. The increase to the target level is expected to take place when the West of Devers upgrades are completed and depends on all necessary upgrades being completed in both the ISO and IID areas. The ISO also notes that upgrades proposed to the IID-owned 230 kV S Line will increase deliverability out of the Imperial area overall and including from IID. The allocation of that deliverability in the future will be available to support deliverability of generation connecting either to the ISO controlled grid or the IID system based on the application of the ISO's tariff and business practices.

## 5.2 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff sections 24.1 and 24.4.6.4

### 5.2.1 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the 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.

### 5.2.2 Data Preparation and Assumptions

The 2016 LT CRR study leveraged the base case network topology used for the annual 2016 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2017-2018 Transmission Plan.

In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). All applicable constraints that were applied during the running of the original LT CRR market 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 representing the transmission ownership rights and merchant transmission were also set to 60 percent. All earlier LT CRR market awards were set to 100 percent, since they were awarded with the system capacity already reduced to 60 percent. For the study year, the market run was set up for four seasons (with season 1 being January through March, season 2 April through June etc.) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted 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.

The ISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. 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 60 percent of enforced branch rating;
- there are overall improvements on the flow of the monitored transmission elements.

### 5.2.3 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 regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

### 5.2.4 Conclusions

The SFT studies involved eight market runs that reflected four three-month seasonal periods (January through December) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned.  In compliance with section 24.4.6.4 of the ISO tariff, ISO followed the LTCRR SFT study steps outlined in section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed.  Based on the results of this analysis, the ISO determined in May 2017 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2017-2018 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

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# Chapter 6

# 6 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's tariff described above, the ISO has also pursued in past transmission planning studies a number of additional "special studies" in parallel with the tariff-specified study processes, to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not the basis for identifying needs or mitigations for ISO Board of Governor approval. In the 2016-2017 planning cycle, the ISO undertook a particularly aggressive number of these studies, recognizing that the initiatives or issues they addressed would likely need additional consideration and effort in future cycles or in other processes implemented to address those issues. Accordingly, the special study work undertaken in this planning cycle largely focused on further efforts in those same areas, with the approach varying on a case by case basis for each study.

The special studies undertaken in this planning cycle and the issues driving those studies are discussed in the following sections and are listed below:

*Addendums performed as extensions of the 2016-2017 transmission planning cycle:*

- Interregional Transmission Project (ITP) Evaluation and 50% RPS Out-of-State Portfolio Assessment (section 6.1)
- Risks of early economic retirement of gas fleet (section 6.2)
- Large scale storage benefits (section 6.3)

*Further study work conducted as part of the 2017-2018 transmission planning cycle:*

- Continuation of frequency response efforts through improved modeling (section 6.4)

*Further study work moving into specific regulatory processes:*

- Gas/electric reliability coordination (section 6.5)
- Slow response resources in local capacity areas (section 6.6)

The special studies discussed in this chapter have not been addressed elsewhere in the transmission plan.

## 6.1 Interregional Transmission Project (ITP) Evaluation and 50% RPS Out-of-State Portfolio Assessment

The ISO conducted studies in the 2017-2018 planning timeline that were in essence a continuation of the studies conducted in the 2016-2017 planning cycle and a supplemental effort to further assess the feasibility of delivering representative 50% RPS out-of-state portfolios from Wyoming and New Mexico to corresponding injection points within the ISO Balancing Authority Area. Those studies relied on the base cases, production cost modeling, and assumptions from that planning cycle, and the completed results were documented as an addendum to the 2016-2017 transmission plan to avoid confusion with analysis derived from the 2017-2018 planning process. A brief summary of the background, development of those studies, and results are provided herein for convenience.

*PREVIOUS INVESTIGATIONS OF IMPACTS OF MOVING BEYOND 33% RPS FOCUSED ON EVALUATING TRANSMISSION INFRASTRUCTURE WITHIN CALIFORNIA.*

During the 2016-2017 planning cycle the ISO undertook a 50% RPS special study (2016-2017 50% RPS study) to focus on a broader investigation into the feasibility and implication of moving beyond 33% RPS from a transmission system perspective. The intent of the 2016-2017 50% RPS study was to build on the 50% studies performed as part of the ISO's 2015-2016 planning cycle to assess 50 percent California RPS portfolios under full capacity deliverability and energy only arrangements. The 2016-2017 50% RPS study also expanded the scope of the initial study effort to acquire general information on system requirements within California that might be needed to import wind resources from Wyoming and New Mexico, and:

1. Investigated the impacts of moving beyond 33% RPS on California's transmission system
2. Tested the transmission capability estimates used in RPS calculator v6.2 and where appropriate, provided updates to these transmission capability estimates; and
3. Carried out a preliminary examination of transmission implications of meeting part of California's 50 percent RPS requirement by assuming California's procurement of 2000 MW of wind resources in Wyoming and 2000 MW of wind resources in New Mexico.

This effort, and the consideration of out-of-state renewable resources in particular, provided a framework for ISO and other western planning regions to coordinate their consideration of those Interregional Transmission Projects that were submitted through the FERC Order No. 1000 interregional coordination process.

While there is considerable interest in exploring how the benefits of interregional transmission projects could help California move beyond 33 percent RPS towards a 50 percent RPS goal, the policy direction is not in place at this time to consider interregional transmission projects as policy-driven transmission. However, recognizing California's interest in examining different possibilities to achieve a 50 percent RPS goal, the ISO chose to consider an interregional coordination effort as an extension of the 50 percent RPS special studies that were being conducted inside the 2016-2017 transmission planning cycle. This capitalized on the first opportunity to employ the biennial interregional coordination process developed by the ISO and neighboring planning regions in compliance with FERC Order No. 1000, which always commences on even-numbered years. As such, during the 2016-2017 planning cycle the ISO worked with the other western planning regions to coordinate an assessment of the interregional project proposals as a means to connect out-of-state renewable resources with California.

The results of that analysis are documented in Section 6.3 of the ISO 2016-2017 Transmission Plan[101].

***Drivers behind this Interregional Transmission Projects (ITP) Evaluation and 50% RPS Out-of-state Assessment***

1. Based on insights gained from 2016-2017 50% RPS special study and consequent stakeholder feedback regarding the out-of-state portfolio assessment, the ISO decided to embark on a supplemental effort this year to further assess the feasibility of delivering the 50% RPS out-of-state portfolio from Wyoming and New Mexico to corresponding injection points within the ISO Balancing Authority Area (BAA).

2. As part of the interregional coordination efforts, the ISO also embarked on an extensive outreach to the Western Planning Regions (WPRs) to refine assumptions that were crucial to evaluate the out-of-state renewable portfolio. This outreach pointed to significant transmission topology assumption refinements that were warranted for the system outside of California owing to the fact that each Western Planning Region (WPR) assesses the 'firmness' of planned transmission projects using different criteria.

*DRIVERS BEHIND THIS ASSESSMENT EMERGED FROM THE INSIGHTS OBTAINED FROM THE PREVIOUS 50% RPS SPECIAL STUDIES AND THE CONSEQUENT STAKEHOLDER INPUT.*

3. The ISO decided to leverage this work being done on the out-of-state portfolio modeling to test the framework to compare effectiveness of ITPs that were submitted as part of the 2016 ITP request window.

4. The ISO also received feedback from stakeholders that production cost simulations and power flow analyses do not entirely capture the challenges with procuring adequate transmission service in order to be able to "count on" out-of-state renewable resources. This prompted an investigation into Available Transmission Capacity (ATC) along the representative paths from Wyoming to California and from New Mexico to California.

The results of the further analysis were presented to stakeholders at the ISO's September 21st and 22nd Stakeholder Session 3 associated with the 2017-2018 planning cycle, and subsequently documented in a separate supplemental report[102] on the 2016-2017 Transmission Planning Process web page on the ISO website.

[101] "2016-2017 Transmission Plan," ISO Board Approved, March 17, 2017, http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf.

[102] "Interregional Transmission Project (ITP) Evaluation and 50% RPS Out-of-State Portfolio Assessment," January 4, 2018, http://www.caiso.com/Documents/InterregionalTransmissionProjectITPEvaluationand50RPSOut-of-StatePortfolioAssessment.pdf.

### 6.1.1 Objectives

The overarching intent was to identify key insights about the transmission impact of out-of-state renewable resources identified by the CPUC as part of the 50% RPS out-of-state portfolio and to leverage this assessment to test-drive a framework to evaluate ITPs. The assessment was designed to meet the following four specific objectives:

1. Refine the out-of-state resource modeling and transmission topology modeling
2. Identify Available Transfer Capability that can be used by the wind resources in WY and NM in order to be delivered to CA
3. Identify transmission constraints outside of CA while trying to meet part of the 50% RPS obligation by relying on a large amount of wind resources in WY and NM
4. Test effectiveness of ITPs in mitigating observed transmission issues outside of CA and test a framework for comparing ITPs

While the above objectives were communicated openly, this initiative also sparked inevitable stakeholder interest in the observations the ISO could draw from the analysis regarding comparisons between the challenges in accessing resources in potentially alternative out of state regions. This also translated into interest in comparisons between alternative interregional transmission projects as potential policy-driven transmission should future state policy direction lead to the need for greater access into the study areas.

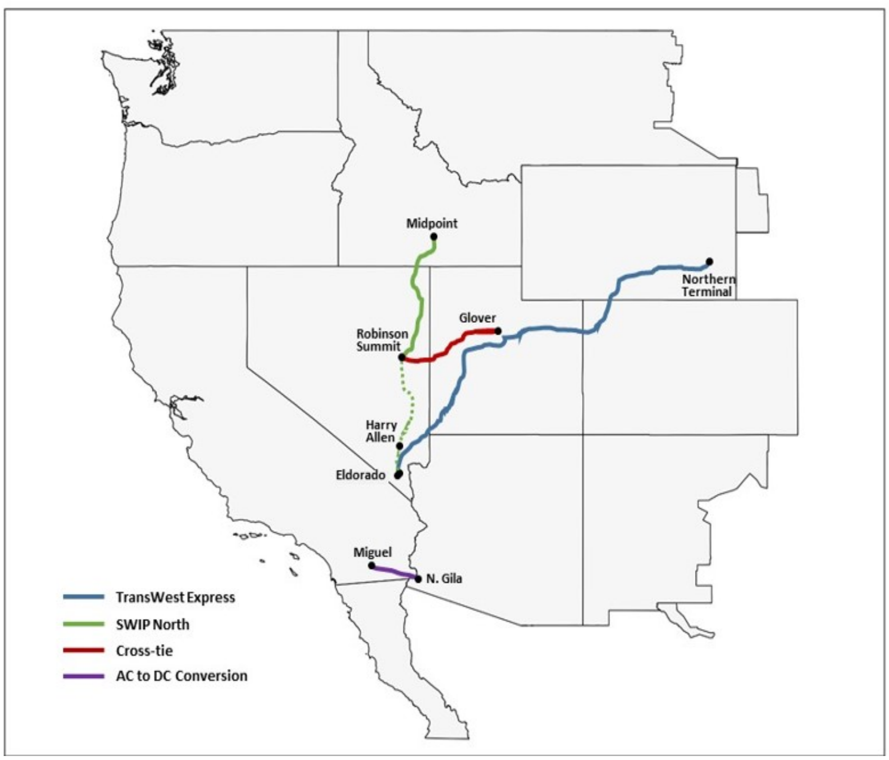
As with the previous analysis, the assessment is strictly for informational purposes. The results should not be construed as reflecting the direction of future inter-regional transmission, renewable generation development or policy direction in California and outside of California nor will this study be a basis for procurement/build decisions in 2016-2017 TPP cycle or 2017-2018 TPP cycle.

#### 6.1.1.1 *Interregional Coordination Background*

During the ISO's 2016-2017 planning cycle, the ISO continued to participate and advance interregional transmission coordination along with the other western planning regions within the broader landscape of the western interconnection. January 1, 2016 marked the initiation of the 2016-2017 western planning region interregional coordination cycle. During the earlier part of 2016 the western planning regions continued to refine aspects of their regional processes that resulted in the development of guiding principles that provided a common framework for an annual exchange and coordination of planning data and information.

As defined by the Common Interregional Tariff Language[103] among the western planning regions, the ISO hosted its interregional transmission project submission period during the first quarter of 2016. Four interregional transmission projects were submitted to the ISO, NTTG, and WestConnect in the submission window. The general location of the projects are shown in Figure 6.1-1 and generally described in Table 6.1-1.

Figure 6.1-6.1-1: Interregional Transmission Projects Submitted to the ISO




[103] *See* the Western Interconnection's Order No. 1000 Interregional Compliance Filings, FERC Docket No. ER13-1470, May 10, 2013, http://www.caiso.com/Documents/May10_2013TariffAmendment-Order1000Phase2%20InterregionalER13-1470-000.pdf.

Table 6.1-6.1-1: Interregional Transmission Project Descriptions

| **Proposed Project** | **Description** |
|---|---|
| TransWest Express Transmission Project | The TransWest Express Transmission Project (TWE Project) is a proposed 730-mile, phased 1,500/3,000 MW, ±600 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada. The Relevant Planning Regions are the ISO, NTTG, and WestConnect. |
| Southwest Intertie Project North | The Southwest Intertie Project (SWIP) is a proposed 275 mile 500kV single circuit AC line that connects the Midpoint 500 kV substation to the Robinson Summit 500 kV substation. The SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. The Relevant Planning Regions are NTTG and WestConnect. (Note that this project was also submitted into the ISO's regional planning process as a potential regional – e.g. ISO – economic driven project.) |
| Cross-Tie Project | The Cross-Tie Transmission Line (Cross-Tie) project is a 213 mile 500 kV HVAC transmission project that will be constructed between central Utah and east-central Nevada. The Cross-Tie Project is expected to have a rating of approximately 1500 MW. The Relevant Planning Regions are NTTG and WestConnect. |
| AC to DC Conversion Project | The AC to DC Conversion Project proposes to convert a portion of the 500 kV Southwest Powerlink (SWPL) to a multi-terminal, multi-polar HVDC system with terminals at North Gila (500 kV), Imperial Valley (500 kV), and Miguel Substations (230 kV). The Relevant Planning Regions are the ISO and WestConnect. |

All four project proposals met the screening requirements of the ISO, NTTG, and WestConnect and were included in the regional planning processes of these regions. Subsequent to meeting the screening requirements the ISO coordinated the development of project evaluation process plans with the other relevant planning regions. These process plans were shared with the project sponsors and ISO stakeholders[104].

A common theme among all projects was a possible role in providing access to out-of-state renewable generation to move California beyond the 33 percent RPS toward a 50 percent RPS

[104] The process plans are available on the ISO's website http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=EAEBC2EA-AE8D-4F8D-A7A6-E477B2ACD085.

goal. As Relevant Planning Regions the ISO, NTTG, and WestConnect were required to develop to coordinate planning data and information related to the interregional transmission projects to ensure that this information was common in all of the regional studies being conducted by the planning regions. As part of this coordination effort, the ISO worked with NTTG and WestConnect to develop a common methodology for scheduling renewable resources in Wyoming and New Mexico to California. The ISO provided NTTG and WestConnect specific details on how these resources should be sinked to California. Alternatively, NTTG and WestConnect provided the ISO with renewable resource information in Wyoming and New Mexico that was modeled in the ISO's studies. It was recognized during the 2016-207 planning cycle that out-of-state RPS studies would continue on beyond the 2016-2017 planning cycle.

### 6.1.2 Study components and methodology

The assumptions, scenarios and portfolios are documented in the 2016-2017 Transmission Plan and the supplemental report referenced above.

The assessment methodology comprised of three main components – (i) Production cost model (PCM) simulations, (ii) Power flow assessment and (iii) Available Transfer Capacity (ATC) assessment.

***PCM simulations***

*A THREE-PRONGED ASSESSMENT INVOLVED PRODUCTION COST MODELING SIMULATIONS, POWER FLOW ASSESSMENT AND ATC ASSESSMENT.*

The PCM simulations were intended to provide insight into:

- Extent of curtailment of out-of-state renewables
- Identification of transmission constraints outside of California that may results in significant amount of congestion when delivering wind resources from WY and NM to the ISO BAA
- Stressed snapshot identification for the purpose of power flow studies
- Impact of ITPs on PCM results

***Power flow assessment***

The intent of the power flow assessment was to –

- Identify additional transmission limitations that may not be captured by PCM studies
- To confirm the transmission system limitations identified by PCM simulation
- Capture the reliability impact of ITPs

The 8,760 hours of power system simulation created during the PCM analysis were used to identify high transmission system usage patterns to be tested using the power flow models for the reliability assessment. A contingency assessment was performed with a focus on the system outside of California.

***Available Transmission Capacity (ATC) assessment***

As part of the ATC assessment the ISO tested if adequate ATC exists for delivering the renewable resources from Wyoming and New Mexico to the ISO BAA. At a conceptual level, this exercise can also provide us with an insight into the 'deliverability' of these out-of-state resources. However, the ISO believes that it is reasonable to assume that large out-of-state resource installations serving California load would not be viable without long-term firm transmission service from the point of receipt to the ISO BAA boundary.

### 6.1.3 Key insights

The key insights garnered in this supplemental effort from the production cost simulation, power flow studies and Available Transmission Capacity (ATC) assessment are as follows:

1. **Impact of transmission development outside of California:** Assumptions about transmission development outside of California (e.g. Gateway Energy Project) have a significant impact on system performance while delivering renewable resources in Wyoming and New Mexico to California. Different planning regions having different criteria for judging "firmness" of planned transmission creates challenges in formulation of unified study assumptions.

2. **Primary driver behind renewable curtailment:** Production cost simulations indicate that transmission constraints are not the primary drivers behind renewable curtailment observed in Wyoming and New Mexico. This conclusion can be drawn from the fact that the total ISO renewable curtailment (including the Wyoming and New Mexico renewables) was almost entirely eliminated when the Net ISO Export limit was relaxed.

3. **Impact of ITPs on renewable curtailment:** ITPs are effective at reducing the renewable curtailment in Wyoming and New Mexico that is observed when the Net ISO Export Limit of 2,000 MW is enforced in production cost simulations. Under this scenario the curtailment of Wyoming and New Mexico renewables is 7% to 8% of the total potential. The two ITPs that are based on building AC lines resulted in lower renewable curtailment than the curtailment observed in scenarios that model Trans West Express HVDC (TWE).

4. **Transmission constraints that must be mitigated:** The southwestern Wyoming system showed severe overloads on the 230 kV local network. These constraints will have to be mitigated in order for any ITP to realize its full potential benefits.

5. **Reliability benefit comparison of ITPs;** The reliability impact based on thermal relief provided by each of the three ITPs aiming to deliver Wyoming wind to California i.e. TWE, Southwest Intertie Project – North (SWIP-N) with Gateway West and Cross-Tie with Gateway South is comparable. REX HVDC project does not greatly impact reliability performance based on thermal relief for delivering resources from New Mexico to California.

- *Inadequate ATC is the biggest hurdle that could be eliminated by development of ITPs.*
- *Renewable curtailment is primarily driven by factors other than transmission limitations.*
- *All the ITPs provide similar thermal loading relief for the bulk transmission system outside*

6. **Severe lack of ATC:** ATC assessment revealed a severe shortage of available contractual transmission capacity to deliver new Wyoming and New Mexico renewables to California. TWE would provide ~1,500 MW of ATC, and is the only ITP that would provide ATC from southwestern Wyoming to southern CA without having to rely on other transmission facilities not owned by the project sponsor. All the other ITPs would have to rely on other existing or planned transmission facilities not owned by the project sponsor in order to provide this level of incremental ATC from Wyoming to California and from New Mexico to California.

Table 6-6.1-2: Summary of directional insights about ITPs

Total ISO renewables including WY and NM wind

Impact on only WY and NM wind curtailment

↓ Reduction in curtailment or overload

— No impact relative to baseline

| | SWIP-N with Gateway West* | Cross-Tie with Gateway South* | TransWest Express | REX HVDC with SunZia |
|---|---|---|---|---|
| ISO renewable curtailment** | — | — | — | — |
| WY wind curtailment** | ↓↓↓ | ↓↓ | ↓ | — |
| NM wind curtailment** | — | — | — | ↓↓ |
| Curtailment (No ISO Export Limit) | — | — | — | — |
| Thermal Overload Performance | ↓↓ | ↓↓ | ↓↓ | — |
| Planning Level Cost*** | $2B - $3.9B | $1.5B - $2.1B | $2.4B – 3.2B | $1.9B - $4.6B |

** SWIP-N and Cross-Tie without certain segments of Gateway were studied and were found to be decisively inadequate for the purpose of delivering Wyoming resources to California*
*** Curtailment under 2,0000 MW Net ISO Export Limit*
**** Based on (i) the request window submittals and (ii) cost information specified in RETI 2.0 Western Outreach Project Report – (http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf)*

| ATC Assessment |
|---|
| • The ISO's examination of yearly, firm, point-to-point ATC data from the Western OASIS points to a severe lack of scheduling capability to deliver Wyoming and New Mexico wind to California<br>• None of the ITPs except TWE will create sufficient long-term, firm ATC from the renewable resource area all the way to the ISO without relying on other transmission not owned by the project sponsor. Note the proponent of the SWIP North project cites having pre-existing arrangements to secure transmission rights on the One Nevada Transmission Line (ON Line), addressing one of two transmission paths needing ATC on other transmission. |

**Observations informative for next steps**

As noted earlier, this initiative also sparked inevitable stakeholder interest in the observations the ISO could draw from the analysis regarding comparisons between the challenges in accessing resources in potentially alternative out of state regions. This also translated into interest in comparisons between alternative interregional transmission projects as potential policy-driven transmission should future state policy direction lead to the need for greater access into the study areas.

A review of the data collected to prepare the analysis as well as the study results themselves do not provide a clear and unequivocal conclusion as to which out of state resource zone is superior, and which interregional transmission project is superior in providing access to out of state resources. A number of attributes that were identified through stakeholder discussion as requiring further consideration given the differing nature of the projects and dependencies:

- How would procurement take place – interregional project, regional project, or as a component of generation procurement – and how would that influence a selection process?
- How will the plans of the ISO out of state neighbors work to support or create challenges for the different alternatives?
- What arrangements with other non-ISO transmission owners for capacity and for development of non-ISO transmission need to be considered and how would those arrangements be developed?
- How will successful project sponsors be selected, and how will cost responsibility be assigned?
- How will staging and sequencing of transmission and generation resources be managed to ensure effective use of resources and periods of underutilization of capacity?

As well, stakeholders commented on the potential for ATC possibly available in the future through the retirement of existing out of state coal-fired generation. While coal fired generation retirements are expected into the future, with the pace driven by economic if not policy reasons, the use for which that capacity will be available will depend on a number of issues, especially the resource plans of the neighboring planning regions.

These issues suggest that further transmission planning analysis alone will not be determinative; that broader consideration through resource policy and resource procurement processes may be necessary before further transmission analysis will be useful. It is very challenging for a transmission planning process to unilaterally land on a preference for the source of out of state renewable resources, or the transmission to access those resources, given the attributes that need to be considered in such a selection. These views were taken into account in developing the recommendations and next steps set out below.

### 6.1.4 Recommendations and Next Steps

The exploratory nature of this effort led to the following recommendations pertaining to next steps that will inform the ongoing IRP proceeding and will refine the ITP evaluation framework in preparation of future planning cycles:

1. Provide the insights obtained from this assessment into CPUC's ongoing IRP proceeding for creation of future RPS portfolios. This will supplement the information already provided by the ISO as part of 2016-2017 TPP 50% special study and RETI 2.0.
2. Continue with preparatory and foundational steps to ensure that the ISO is positioned to support the anticipated policy and procurement activities that in turn will inform future transmission planning activities. These include:
   - Create a framework for accounting for interdependencies of ITPs and other non-ITP infrastructure projects while evaluating ITPs.
   - Incorporate ATC assessment as part of the ITP evaluation framework for future ITP request window submittals. Create a repeatable process to coordinate with the respective Transmission Providers (TPs) to retrieve the most accurate ATC data on the requested paths in a timely manner.

Continue to explore the other attributes that would be taken into account in selecting a "preferred" project to access out of state wind resources. These would include attributes such as how transmission would be procured, arrangements with non-ISO transmission owners for capacity, staging and sequencing of transmission and generation resources.

## 6.2 Risks of early economic retirement of gas fleet

The ISO conducted studies in the 2017-2018 planning timeline that were a continuation of the studies conducted in the 2016-2017 planning cycle and a supplemental effort to update the analysis and conduct additional sensitivities of potential risks to system reliability if similarly economically-situated generators retire more or less simultaneously.

Those studies relied on the base cases, production cost modeling, and assumptions from that planning cycle, and the completed results were documented as an addendum to the 2016-2017 transmission plan to avoid confusion with analysis derived from the 2017-2018 planning process. A brief summary of the background, development of those studies, and results are provided herein for convenience.

The results of the further analysis were presented to stakeholders at the ISO's September 21st and 22nd Stakeholder Session 3 associated with the 2017-2018 planning cycle, and subsequently documented in a separate supplemental report[105] on the 2016-2017 Transmission Planning Process web page on the ISO website.

### 6.2.1 Background

During the 2016-2017 planning cycle the ISO undertook a preliminary analysis of potential risks to system reliability if similarly economically-situated generators retire more or less simultaneously. The study and results were documented in Section 6.1 of the 2016-2017 Transmission Plan.

The significant amount of new renewable generation capacity being added to the grid is also putting economic pressure on the existing gas-fired generation fleet, especially for those generators not obtaining resource adequacy contracts. Further, the bulk of the grid-connected renewable generation developed to date has been "deliverable", e.g. capable of providing capacity towards the state's resource adequacy program, leaving more uncertainty as to the future of system resource adequacy compensation availability for the existing gas-fired generation fleet. Compensation for provision of flexibility services can also be uncertain, with the gas-fired generation fleet facing competition from other sources.

As generation owners are independently assessing market conditions and their own particular circumstances, the ISO undertook preliminary analysis of potential risks to system reliability if similarly economically-situated generators retire more or less simultaneously.

This analysis focused on two aspects of reliability:

- Are there localized areas of the grid transmission system where the retirement of a number of similarly situated generators would create reliability issues or other negative impacts on the operation of the transmission system, and,

[105] "Supplemental Sensitivity Analysis: Risks of early economic retirement of gas fleet", January 4, 2018, http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-Risksofearlyeconomicretirementofgasfleet.pdf.

- Are system-wide reliability requirements, e.g. load following, operating reserves and regulating reserve levels, unduly compromised?

To study the second aspect regarding system-wide reliability, the study relied upon Energy Exemplar's PLEXOS production simulation package and approach consistent with the methodologies employed by the ISO in participating in the CPUC's long term procurement plan (LTPP) proceeding. It used the Base Case that is discussed in section 6.5 "Benefits Analysis of Large Energy Storage" of the ISO 2016-2017 Transmission Plan.[106]

In the course of that process, the need for additional sensitivity studies was identified, which were conducted in 2017.

### 6.2.2 Objectives of Further Study

The assumptions, scenarios and portfolios are documented in the 2016-2017 Transmission Plan and the supplemental report referenced above. Building on assumptions, scenarios and portfolios, this additional sensitivity analysis consisted of two sensitivity cases:

The first sensitivity case focused on the impacts of additional achievable energy efficiency (AAEE) forecast:

- The Base Case considered in the 2016-2017 analysis had the SB350 AAEE assumption that the 2015 IEPR Mid-AAEE forecast will be doubled by 2030
- This sensitivity replaced that SB350 AAEE assumption with the 2015 IEPR Mid-AAEE forecast, aligning with other 2016-2017 plan results

The second sensitivity explored the impact of various combinations of CCGT or GT retirement, based on the first sensitivity case described above (e.g. also relied upon the 2015 IEPR Mid-AAEE forecast):

- Evaluated the effects of retirement of 2,000 MW of CCGT or GT, or the combination of the two types of resources

### 6.2.3 Summary of Results

The study results from the 2016-2017 – the base case - analysis and the results of the latest sensitivity analysis are summarized below.

*<u>Base Case</u>*

The results of the Base Case were discussed in Section 6.1.3.3 of the ISO 2016-2017 Transmission Plan. From the study, it was concluded that:

- Unlimited renewable curtailment masks the need for flexible capacity during downward ramping in the morning and upward ramping in the afternoon;

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[106] "2016-2017 Transmission Plan," ISO Board Approved March 17, 2017, http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf.

- The shortfalls in load-following and reserves reflect the insufficiencies of capacity;
- Capacity insufficiencies occur in early evening after sunset, which is the new peak (net) load time; and,
- Capacity insufficiency started to emerge with between 4,000 to 6,000 MW of retirement, considering some uncertainties in the modeling assumptions, and in particular, with the SB350 AAEE assumption that the 2015 IEPR Mid-AAEE forecast will be doubled by 2030.

*Supplemental Sensitivity Cases*

In the first sensitivity case, with the AAEE reduced to the 2015 IEPR Mid-AAEE forecast, only 1,000 to 2,000 MW gas-fired generation capacity could be retired without causing capacity insufficiency reliability issues.

In the second sensitivity case, the three combinations of CCGT and GT capacity retirement showed different impacts. In the case of retiring 2,035 MW of CCGT the ISO needed to use more import and GT generation to replace the "baseload" CCGT generation. That increased CO2 emissions for both California and WECC. On the other hand, with 2,031 MW of GT retirement, the ISO lost flexibility of its generation fleet and needed to use less flexible CCGT to follow load. The direct impact was that more renewable generation was curtailed to reduce the needs for ramping capability. The combination of the two, retiring 1,010 MW CCGT and 1,017 MW GT, provided a more balanced outcome.

## 6.3 Benefits Analysis of Large Energy Storage

The ISO conducted studies in the 2017-2018 planning timeline that were a continuation of the studies conducted in the 2016-2017 planning cycle and a supplemental effort to assess the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves towards higher renewable generation levels by considering additional sensitivities.

Those studies relied on the base cases, production cost modeling, and assumptions from that planning cycle, and the completed results were documented as an addendum to the 2016-2017 transmission plan to avoid confusion with analysis derived from the 2017-2018 planning process.

A brief summary of the background, development of those studies, and results are provided herein for convenience.

As discussed in more detail below, the 2016-2017 Base Case assumptions generally leaned to underestimate the value the large scale storage would reasonably be able to provide, leading to the additional sensitivity analysis performed in 2017.

It must also be noted that the planning assumptions included in the additional sensitivity analysis were finalized in early 2017. This analysis does not reflect ongoing evolution of the CPUC's Integrated Resource Planning proceeding, or changes in planning assumptions being made through that process.

The results of the further analysis were presented to stakeholders at the ISO's September 21st and 22nd Stakeholder Session 3 associated with the 2017-2018 planning cycle, and subsequently documented in a separate supplemental report[107] on the 2016-2017 Transmission Planning Process web page on the ISO website.

### 6.3.1 Background

During the 2016-2017 planning cycle, the ISO undertook further study of the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves from the 33 percent RPS to a 50 percent RPS. This analysis began in the 2015-2016 transmission planning cycle with a 40 percent RPS-based analysis that was later updated to a 50 percent RPS-based analysis.[108] The 2016-2017 study used the same methodology as the previous ones and provided a further update using the latest assumptions and load forecasts, and assessed the benefits in reduction of renewable generation curtailment, $CO_2$ emission and production cost as well as the financial costs to achieve the benefits. The ISO also expanded the study scope to consider potential locational benefits.

The study and results were documented in Section 6.5 of the 2016-2017 Transmission Plan.

107 "Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage", January 4, 2018, http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf.

108 "2015-2016 Transmission Plan," ISO Board Approved March 28, 2016, http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf and "A Bulk Energy Storage Resource Case Study update from 40% to 50% RPS," http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf.

The study was provided on an information-only basis and the results are dependent on the assumptions made in the study. The methodology, assumptions, and results of the study are set out in this section.

*Initial Base Case in 2016-2017 Analysis*

The 2016-2017 special study was conducted based on the 50 percent RPS "in-state portfolio with full capacity deliverability" portfolio the CPUC provided for the ISO 2016-2017 50 percent RPS special studies. The 50 percent RPS Base Case was developed based on the Default Scenario of the CPUC 2016 LTPP/TPP Assumptions and Scenarios.[109] The assumptions have some major changes compared to that of the last 50 percent RPS based bulk energy storage study in the 2015-2016 transmission planning cycle. The changes are mostly in the following areas:

- The retirement of non-dispatchable generation resources;
- Dispatchability of CHP resources;
- Energy forecast and Additional Achievable Energy Efficiency (AAEE);
- Renewable energy needed to achieve the 50 percent RPS target (no curtailment included); and
- The prices for renewable curtailment.

Table 1 below has the comparison of these changes.

[109] "Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for use in the California Independent System Operator's 2016-2017 Transmission Planning Process and Future Commission Proceedings," issued in the *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans,* Proceeding No. R.13-12-010, May 17, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF.

Table 6.3-1: Comparison of Assumptions with Major Changes

| Assumption | 2016-2017 TPP 50% RPS Study | 2015-2016 TPP 50% RPS Study |
|---|---|---|
| Changes in non-dispatchable generation resources | Diablo Canyon nuclear plant (2,300 MW) is retired<br>2,786 MW CHP in operation | Diablo Canyon in operation<br><br>4,684 MW CHP in operation |
| Dispatchability of CHP resources | 50% of the 2,786 MW CHP is dispatchable | All 4,684 MW CHP is non-dispatchable |
| California load forecast | 64,009 MW 1-in-2 No AAEE non-coincident peak load<br>301,480 GWh energy | 70,763 MW 1-in-2 No AAEE non-coincident peak load<br>322,218 GWh energy |
| California AAEE | 9,418 MW non-coincident peak impact<br>39,779 GWh energy<br>CEC provided hourly profiles that usually have higher values in the late afternoon and early evening | 5,713 MW non-coincident peak impact<br>24,535 GWh energy<br>No hourly profile, offsetting load proportionally to the hourly load values |
| California RPS Portfolio | 36,776 MW installed capacity<br>110,288 GWh energy | 40,986 MW installed capacity<br>125,307 GWh energy |
| Price of renewable generation curtailment | -$15/MWh for the first 200 GWh, -$25/MWh for additional 12,400 GWh and -$300/MWh thereafter | -$300/MWh for all curtailment |
| Hydro condition | 2005 hydro generation | 2005 hydro generation |
| ISO maximum net export capability | 2,000 MW | 2,000 MW |

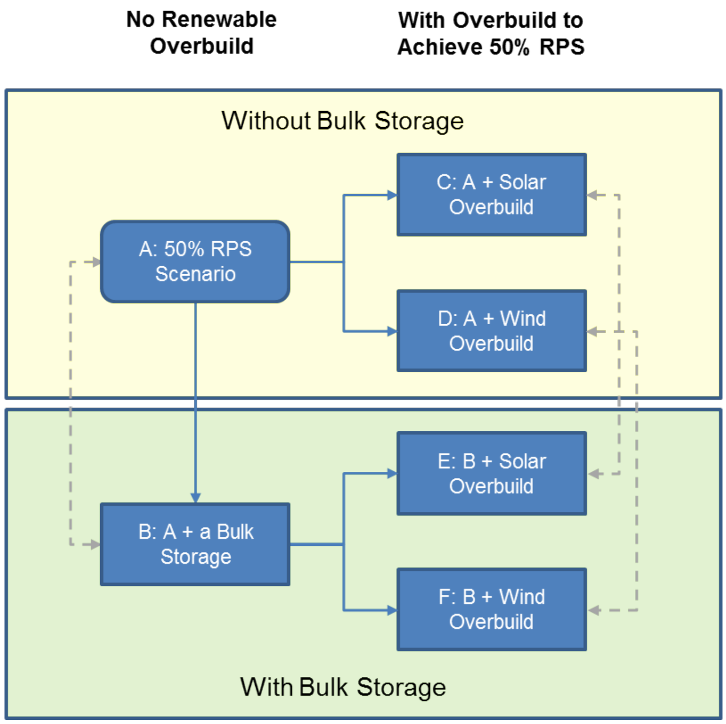
Two new bulk energy storage resources – a 500 MW and a 1400 MW resource – were added in turn to the 50 percent RPS scenario production simulation model to evaluate its contribution to reduction of renewable curtailment, CO2 emission, and production cost.

*Initial Study Cases*

Consistent with the studies the ISO did in the 2015-2016 transmission planning process, the study was based on production simulations – for each size of resource – of the original case and five new cases, as shown in Figure 1, as a simple comparison of two production cost simulations – with and without the bulk energy storage resource – does not determine the full benefits the resource may provide, as the presence of the storage resource may lead to different levels of success of various renewable resource mixes in achieving the 50 percent RPS target.

The five cases were all derived from the 50 percent RPS scenario Base Case, which was designated as case **A** in this study. In all cases, renewable curtailment remains unlimited. Case **B** is case **A** with the new bulk energy storage resource added. As expected, the actual renewable generation did not initially meet the state's 50 percent renewable portfolio standard (RPS) goal in the production simulations due to the amount of curtailment. In case **B** the 50 percent RPS target was still not achieved due to curtailment. In the other four cases (case **C**, **D**, **E** and **F**), additional renewable generation resources were added to the renewables portfolio of case **A** and case **B** until the actual renewable generation met the 50 percent RPS requirement despite the curtailment. The additional renewable resources are in effect the renewable overbuild needed to achieve the 50 percent RPS target and overcome the curtailment impacts on total renewable energy production.

Figure 1: Definition of Study Cases




In this study the renewable overbuilds used two alternative resources; solar and wind. Solar and wind have very different generation patterns (hourly profiles). In the 50 percent RPS scenario (case **A**), installed solar capacity was 55% of the total RPS portfolio and wind was 32%, excluding the distributed solar PV. Solar generation peaks in the midday and causes curtailment when the generation is more than the system can utilize. Solar overbuild further increased the solar dominance in the RPS portfolio and added more generation in the hours already having curtailment in case **A**. That portion of solar generation was then all curtailed. On the other hand, wind generation in California usually spreads over the whole day, with lower output in the midday than solar. Therefore, wind overbuild improved the diversification of the RPS portfolio. It has less generation to be curtailed than solar does. The needed wind overbuild was expected to be less than solar overbuild. Also the capital cost (per kW) of wind is lower than that of solar (see Table 2). As shown in Figure 1, the four cases with renewable overbuild were constructed to have either solar (case **C** and **E**) or wind (case **D** and **F**) overbuild. The purpose was to establish two bookends in term of quantity (MW) and capital cost of the overbuild. As a solution to renewable curtailment, the actual renewable overbuild should be combinations of solar and wind, as well as other types of renewable resources.

Table 2: Assumptions for Revenue Requirements and RA Revenue

| Item | Generation & Transmission Costs (2016$/kW-year) [110] | NQC Peak Factor [111] | RA Revenue ($/kW-year)[112] |
|---|---|---|---|
| Large Solar In-State | 242.19 | 47% | 16.53 |
| Large Solar Out-State | 183.17 | 47% | 16.53 |
| Small Solar In-State | 334.80 | 47% | 16.53 |
| Solar Thermal In-State | 551.55 | 90% | 31.66 |
| Wind In-State | 239.14 | 17% | 5.98 |
| Wind Out-State | 223.88 | 45% | 15.83 |
| Pumped Storage In-State | 407.91 | 100% | 35.18 |

*Need for additional analysis*

The Base Case assumptions generally leaned to underestimate the value the pumped storage is reasonably able to provide. They provided a starting point of the studies, however, to help focus further study. As a result, the ISO committed to analyze additional sensitivity cases to assess the costs and benefits of the bulk energy storage resource in supporting integration of high penetration renewable energy in the ISO market, which is the subject of this addendum. These parameters do not affect the consideration of locational benefits of the various sites considered in the 2016-2017 Transmission Plan analysis; locational benefits did not receive further study in this sensitivity analysis.

### 6.3.2 Objectives of Further Study in 2017

The objective of the further study conducted in 2017 was to address the additional sensitivity analysis identified as needed in the 2016-2017 transmission planning process.

First, the Default Scenario was updated after the initial results were presented to the stakeholders in the 2016-2017 transmission planning process, changing the import from out-of-state RPS resources:

[110] "Resolve Model," prepared by Energy & Environmental Economics, Inc., Version 2.0, last updated December 5, 2016, available on the CPUC's website at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/DRAFT_RESOLVE_Inputs_2016-12-21.xlsx; "2014 WECC Capital Cost Model," prepared by Energy & Environmental Economics, Inc., May 15, 2014, available on WECC's website at https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm; and "Capital Cost Review of Power Generation Technologies – Recommendations for WECC's 10-and 20-Year Studies," March, 2014, https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.

[111] "2012 TAC Area Factors," for wind and solar, available from the ISO at https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls, and *see* WECC's 2024 Common Case, Version 1.5, (April 9, 2015), https://www. wecc.biz/Reliability/2024-Common-Case.zip.

[112] "The 2015 Resource Adequacy Report," by CPUC Energy Division, January 2017, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221.

- The study assumes that 70% of out-of-state RPS generation needs to be imported into the ISO
- The Default Scenario in 2016-2017 TPP allows the import to be exported back
- This update changes the RPS import into Category 1 and 2 RPS, which has to stay in the ISO
- The change reduces allowed net export when there is curtailment of renewable generation in the ISO.

Those additional sensitivity analyses focused on the following assumptions:

- Dispatchability of CHP resource (The updated Default Scenario assumed 50% of CHP resources are dispatchable – this sensitivity assumes all CHP is non-dispatchable.)
- Level of AAEE (The updated Default Scenario assumed the 2015 IEPR Mid-AAEE will be doubled in 2030 – this sensitivity assumes the 2015 IEPR Mid-AAEE forecast for 2026)
- Prices of renewable curtailment (the updated Default Scenario assumed that the first 200 GWh renewable will be curtailed at -$15/MWh, additional 12,400 GWh renewable will be curtailed at -$25/MWh, the rest at -$300/MWh. The curtailment in the Default case did not go beyond 3,000 GWh, so the -$300/MWh curtailment was never triggered.) This sensitivity assumes 4 tiers of curtailment price as noted below:

Table 6.3-2: Curtailment prices

| | Tier 1 | Tier 2 | Tier 3 | Tier 4 |
|---|---|---|---|---|
| Curtailment Price ($/MWh) | -15 | -25 | -50 | -150 |
| Max Curtailment (GWh) | 200 | 1,300 | 500 | All the rest |

So the effective renewable curtailment prices in this sensitivity case is lower than that in the Default Scenario.

### 6.3.3 Summary of System Benefit Results

The study results from the 2016-2017 analysis – with the update to the Default Scenario and the results of the further sensitivity analysis are set out in the supplemental report referenced above.

Based on the results of the initial study and further analysis, it can be concluded that:

- The new pumped storage resources brought significant benefits to the system, including reducing renewable curtailment and renewable overbuild needed to meet the 50% RPS target;
    - making use of the recovered renewable energy from curtailment as well as low cost out-of-state energy during hours without renewable curtailment;

  - o providing lower cost energy during the net peak hours in early evening and flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes; and,
  - o lowering system production cost to serve the load.
- The new pumped storage resources also took advantage of low cost out-of-state energy during hours without renewable curtailment. They also resulted in higher net import to California and slightly increased CO2 emissions[113] within California footprint.
- Pumped storage was more effective with a high solar concentration renewables portfolio than with a more diversified renewables portfolios. However a more diversified renewables portfolio has more system benefits, resulting in overall lower costs through lower curtailment, production cost and revenue requirement.
- Compared to the study with 50% RPS in 2015-2016 TPP, results of this study show significantly lower renewable curtailment, mainly due to the following assumptions:
  - o Retirement of Diablo Canyon and non-dispatchable CHP resources;
  - o Dispatchability of 50% of CHP resources; and
  - o Lower load forecast together with higher AAEE, and the resulted lower renewable energy needed to achieve the 50% RPS target
- Because of low renewable curtailment, the effectiveness of the pumped storage resources in reducing renewable curtailment, renewable overbuild, and production costs was limited in this study.
- The net market revenue of the pumped storage resources provided only a portion of the levelized annual revenue requirements. Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions.
- The results of the study are sensitive to the assumptions, especially the dispatchability of the CHP resources, the level and AAEE, and the prices of renewable curtailment. The conclusions about the benefits and costs of the pumped storage resources will change should the assumptions change.
- When all CHP resources are assumed to be non-dispatchable, the renewable curtailment as well as the needed renewable overbuild to meet the 50% RPS target increased significantly, as do the production costs. The pumped storage resources were able to take advantage of the higher curtailment and increased their net market revenue and benefits to the system. However, the sum of net market revenue and system benefits still fell short to meet the levelized revenue requirements of the pumped storage resources.
- With the AAEE reduced to the 2015 IEPR forecasted level (see Table 1), retail sales of electricity increases and more renewable energy is needed to meet the 50% RPS target. Then more solar is added to the RPS portfolio. As a result, more solar generation was curtailed in the simulations and more overbuild was needed. The production cost also

[113] The slightly increased CO2 emissions result from the assumptions regarding the GHG adder relied upon in the study and the assumption that the pumped storage would pump when low cost energy is available regardless of source. Higher GHG adders or other restrictions on these pumping opportunities would mute this impact, albeit with some corresponding impact on benefits.

increased because more flexible non-renewable resources were utilized to support the renewable generation. The pumped storage resources were able to take advantage of more renewable curtailment to increase their net market revenue and their contribution to the system.

- With lower renewable curtailment prices, renewable curtailment was reduced, so was the needed renewable overbuild, the system production cost, the pumped storage resources' net market revenue and their benefits to the system.

### 6.3.4 Locational benefits

The initial 2016-2017 planning cycle analysis included preliminary assessments of the locational benefits of known potential large energy storage sites; Lake Elsinore, Eagle Mountain, and San Vicente. The additional sensitivity analysis did not revisit locational benefits. The analysis approach for each site was designed to capture the expected potential locational benefits for that particular site.

The 2016-2017 Transmission Plan provides a more detailed discussion. Summarizing the results of that analysis:

- Eagle Mountain was considered for potential congestion benefits as it is located in the Riverside renewable zone, and renewable generation from that zone must be transmitted over 100 miles across major transmission paths to the coastal load areas to the west. The Riverside renewable zone could be potentially congested due to a large amount of renewable development in the area.
- The amount of congestion in these models affecting the Riverside renewable generation was minimal, and the Eagle Mountain storage project did not materially reduce any of the identified congestion. The ISO also performed a loss benefit analysis, and a marginal transmission line loss improvement was observed as a result of adding the Eagle Mountain storage project to the model.
- As the Lake Elsinore and San Vicente storage projects are located in the San Diego load center, and this area requires local generation capacity to reliability serve the San Diego area load both projects could provide local capacity benefits. The San Vicente storage projects would be interconnected at a location that would be effective providing local resource adequacy capacity into San Diego. The Lake Elsinore project has several interconnection configurations that have been considered, but for the purposes of this study it was assumed that this project would be connected to the San Diego area because this configuration would be capable of providing local capacity benefits. The ISO did not attempt to quantify the economic benefit of the local capacity resources.
- No line loss benefits were identified for either project.

## 6.4 Frequency Response Assessment – Generation Modeling

As penetration of renewable resources increases, conventional generators are being displaced with renewable resources. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. Many of these concerns relate directly or indirectly to the “duck curve”, highlighting the need for flexible ramping generation but also for adequate frequency response to maintain the capability to respond to unplanned contingencies as the percentage of renewable generation online at any time climbs and the percentage of conventional generation drops.

Over past planning cycles, the ISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in our analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

The ISO has therefore been conducting studies and model collection and validation efforts over the past several years to identify priority areas for improving generation modeling in power flow and stability analysis. This effort is critical both due to identified areas of concern with the models and data presently available, as well as the increasing requirements in NERC mandatory standards.

The efforts conducted in the time frame of the 2017-2018 planning cycle have focused primarily on data collection and model validation, and that effort has experienced a number of challenges in that regard. In the subsections below, the progress achieved and issues to be considered going forward has been summarized, as well as the background setting the context for these efforts.

### 6.4.1 Frequency Response and Over generation issues

The ISO’s most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in the 2015-2016 ISO Transmission Plan built on the analysis.

**Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting)**

On January 16, 2014 FERC approved Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard created a new obligation for balancing authorities, including the ISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined obligation. Compliance with BAL-003-1 began December 1, 2016.

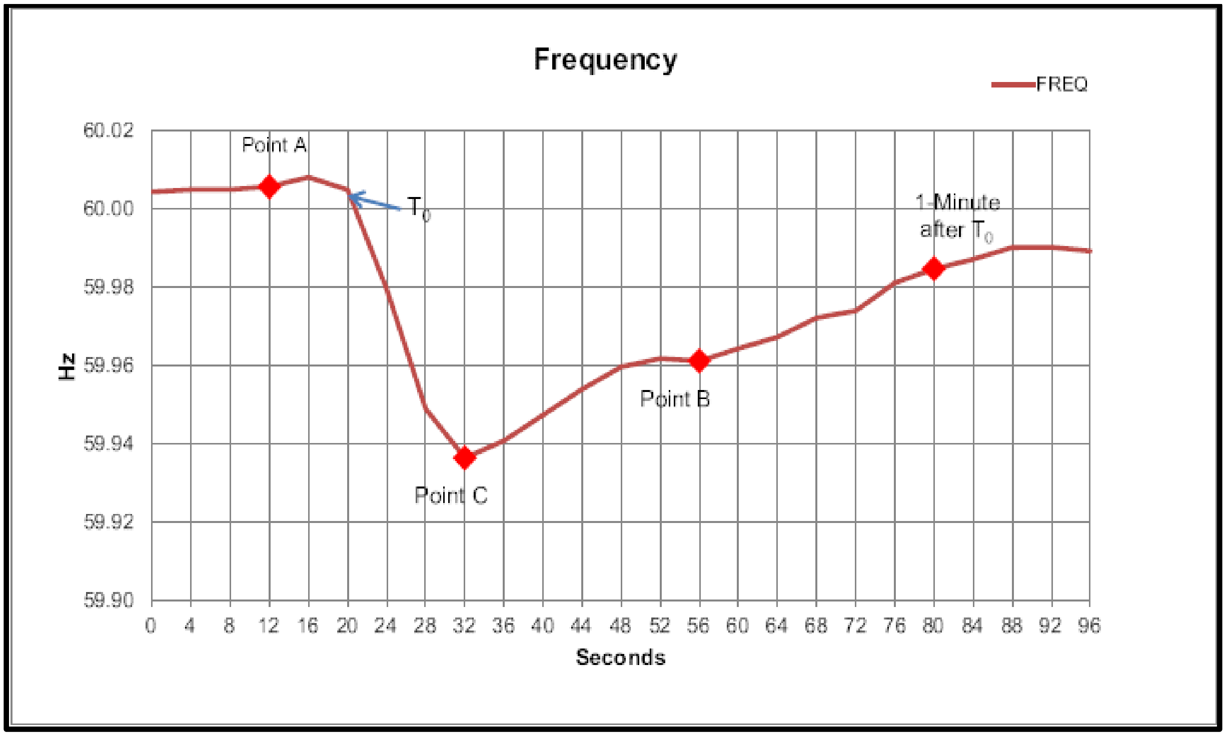
NERC has established a methodology for calculating frequency response obligations (FRO). A balancing authority’s FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the Interconnection Frequency Response Obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC

Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde Nuclear Generation Station (2,626 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

To assess each balancing authority's frequency performance, NERC selects at least 20 actual disturbances involving drop in frequency each year, and measures frequency response of each balancing authority to each of these disturbances. Frequency response is measured in MW per 0.1 Hz of deviation in frequency. The median of these responses is the balancing authority's Frequency Response Measure (FRM) for the year. It is compared with the balancing authority's FRO to determine if the balancing authority is compliant with the standard. Thus, the BAL-003-1 standard requires the ISO to demonstrate that its system provides sufficient frequency response during disturbances that affected the system frequency. To provide the required frequency response, the ISO needs to have sufficient amount of frequency-responsive units online, and these units need to have enough headroom to provide such a response. Even though the operating standard measures the median performance, at this time planners assume that the performance should be targeted at meeting the standard at all times, and that unforeseen circumstances will inevitably lead to a range of outcomes in real time distributed around the simulated performance.

Figure 6.4-1 illustrates a generic system disturbance that results in frequency decline, such as a loss of a large generating facility. Pre-event period (Point A) represents the system frequency prior to the disturbance with $T_0$ as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.4-1: Illustration of Primary Frequency Response




The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

Frequency response of the Interconnection's Frequency Response Measure or FRM) is calculated as

$$FR = \frac{\Delta P}{\Delta f}\left[\frac{MW}{0.1Hz}\right]$$

Where ΔP is the difference in the generation output before and after the contingency, and Δf is the difference between the system frequency just prior to the contingency and the settling frequency. For each balancing authority within an interconnection to meet the BAL-003-1 standard, the actual Frequency Response Measure should exceed the FRO of the balancing authority. FRO is allocated to each balancing authority and is calculated using the formula below.

$$FRO_{BA} = FRO_{Int} \frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. The studies performed by the ISO in 2015 used the WECC FRO for 2016 that was determined as 858 MW/0.1 Hz and being on a conservative side, assumed that the ISO's share is approximately 30 percent of WECC, which is 258 MW/0.1 Hz. It remained the same for 2017. For 2018, the Western Interconnection FRO was calculated as 895 MW/0.1 Hz, thus the ISO share will be 268.5 MW/0.1 Hz.

The NERC frequency response annual analysis report that specifies Frequency Response Obligations of each interconnection can be found on the NERC website[114].

The transition to increased penetration of renewable resources and more conventional generators being displaced with renewable resources does affect the consideration of frequency response issues. Most of the renewable resources coming online are wind and solar photovoltaic (PV) units that are inverter-based and do not have the same inherent capability to provide inertia response or frequency response to frequency changes as conventional rotating generators. Unlike conventional generation, inverter-based renewable resources must be specifically designed to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their output in response to a decline in frequency. While a frequency response characteristic can be incorporated into many inverter-based generator designs, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has upward ramping headroom remaining. To provide this inertia-like frequency response, wind and solar resources would have to have the necessary controls incorporated into their designs, and also have to operate below their maximum capability for a certain wind speed or irradiance level, respectively, to provide frequency response following the loss of a large generator. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-1 for all operating conditions.

The most critical conditions when frequency response may not be sufficient is when a large amount of renewable resources is online with high output and the load is relatively low, therefore many of conventional resources that otherwise would provide frequency response are not

[114] "2017 Frequency Response Annual Analysis," November 2017, http://www.nerc.com/comm/oc/bal0031_supporting_documents_2017_dl/2017_fraa_final_20171113.pdf.

committed. Curtailment of renewable resources either to create headroom for their own governor response, or to allow conventional resources to be committed at a minimum output level is a potential solution but undesirable from an emissions and cost perspective.

**Generation Headroom**

Another metric that was evaluated was the headroom of the units with responsive governors. The headroom is defined as a difference between the maximum capacity of the unit and the unit's output. For a system to react most effectively to changes in frequency, enough total headroom must be available. Block loaded units and units that don't respond to changes in frequency (for example, inverter-based or asynchronous renewable units) have no headroom.

The ratio of generation that provides governor response to all generation running on the system is used to quantify overall system readiness to provide frequency response. This ratio is introduced as the metric Kt; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt is not standardized.

For the ISO studies, it was defined as the ratio of power generation capability of units with governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch.

**2014-2015 and 2015-2016 Transmission Plan Study Results**

The ISO assessed in the 2014-2015 and in 2015-2016 transmission planning processes the potential risk of oversupply conditions – a surplus of renewable generation that needs to be managed - in the 2020-2021 timeframe under the 33 percent renewables portfolio standard (RPS) and evaluated frequency response during light load conditions and high renewable production. Those studies also assessed factors affecting frequency response and evaluated mitigation measures for operating conditions during which the FRO couldn't be met.

The ISO 2014-2015 Transmission Plan[115] in section 3.3 and the ISO 2015-2016 Transmission Plan[116] in section 3.2 discuss reliability issues that can occur during oversupply conditions when inverter-based renewable generation output is high, and also describe frequency performance metrics and study results.

Studies performed in the previous transmission planning processes showed that the total frequency response from WECC was above the interconnection's frequency response obligation, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant. When the study results and, in particular, response of some individual generation units was compared with the real time measurements during frequency disturbances, the results of the simulations did not match the actual measurements showing higher response

[115] "2014-2015 Transmission Plan," ISO Board Approved March 27, 2015, http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf.

[116] "2015-2016 Transmission Plan," ISO Board Approved March 28, 2016, http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

to frequency deviations. Thus, the study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed.

### 6.4.2 New NERC Standards MOD-032 and MOD-033 Modeling Requirements

NERC standards MOD- 032 and MOD -033 also set direction for improved generator modeling.

According to the NERC Standard MOD-032, each Balancing Authority, Planning Authority and Planning Coordinator should establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. The NERC MOD-032 standard is related to the NERC Standard MOD-033. The MOD-032 standard requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by FERC recommendations and directives.

Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner and Planning Coordinator according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner. If the Planning Coordinator or Transmission Planner has technical concerns regarding the data, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall either provide the updated data or explain the technical basis for maintaining the current data. Each Planning Coordinator shall make available models for its planning area reflecting the provided data to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide cases that include the Planning Coordinator's planning area. For the ISO, Transmission Planners and generation owners are responsible for providing the data, and the ISO is responsible for the model validation.

The purpose of the NERC Standard MOD-033-1 is to establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

The focus of validation in this standard is not Interconnection-wide phenomena, but events on the Planning Coordinator's portion of the existing system, although system-wide disturbances can also be used for model validation. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

The MOD-033-1 standard requirements include comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other real-time data sources. Such model validation has to be done at least once in the 24 months. The standard includes guidelines needed to be used to determine unacceptable difference in the model's performance. The standard states that each Reliability Coordinator and Transmission Operator shall provide actual system behavior data to any Planning Coordinator performing validation such as, state estimator case or other real-time data necessary for actual system response validation.

The reliability standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. In accordance with the MOD-033 standard, the ISO developed a Power System Model Validation Process in 2017 that includes guidelines on how to perform model validation. It also includes a methodology of comparison of the ISO performance in planning power system model and dynamic stability response simulations to actual system behavior. These guidelines explain how to determine unacceptable differences in the evaluated performances for the planning power flow and dynamic model and how to resolve them. The Model Validation Process is followed by Reliability Coordinators, Transmission Operators and Transmission and Generation Owners.

### 6.4.3 Generator Modeling Issues observed in past ISO studies

While performing power flow and dynamic stability studies in past processes, the ISO encountered the following potential generator modeling issues.

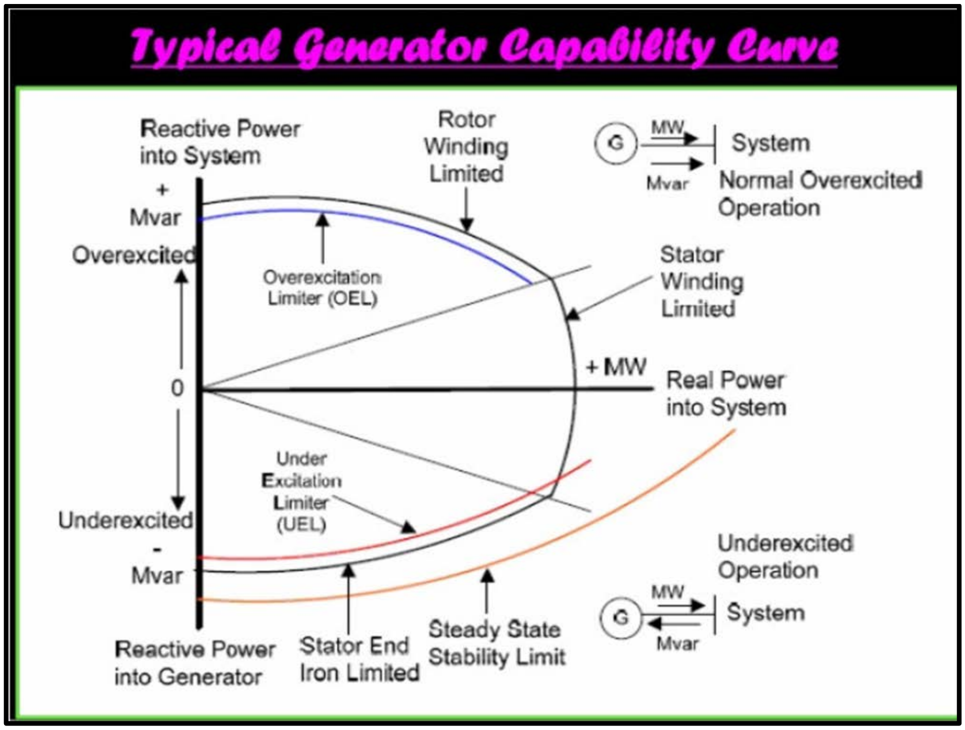
**Possible inadequate reactive capability modeling**

This issue is more applicable to the new renewable units, when it is not clear if the unit is capable of regulating voltage. Thus, power flow model may not match dynamic stability model. Generation owners of inverter-based and induction generation units need to provide accurate data of their units' reactive capability, and it needs to be modeled consistently both in power flow and dynamic stability. Accurate data is needed, since reactive capability of inverter-based generation may have significant impact on the system performance.

Generation owners of synchronous units need to provide reactive capability curves for their units, and these curves should be adequately modeled. The latest version of the GE PSLF program allows modeling of the whole reactive capability curves, and not just maximum and minimum reactive capability. Having the whole reactive capability curve modeled, will allow more accurate results in voltage stability and reactive margin studies.

Figure 6.4-2 illustrates typical reactive capability curve of a synchronous generator.

Figure 6.4-2: Reactive Capability Curve of a Synchronous Generator




### Absence of models

Often new generation developers haven't determined, when applying for interconnection, which type of inverters and control system settings will be used. Therefore, in the generation interconnection studies, generic models with typical parameters are often used. Although WECC requires generation testing prior to the start of commercial operation, often this is not done, and the typical generic data included in the dynamic database is not being updated. Also, some models of new and existing generation in the dynamic database have missing components, such as control systems, governors, or generation protection.

### Errors in dynamic models

After screening the dynamic database, numerous potential errors were identified. For example, some existing wind generators were modeled as thermal, solar PV units were modeled as wind, and induction generators modeled as inverters. Also, there were some erroneous model values or inadequate tuning of parameters that in dynamic stability simulations may result in oscillations or criteria violations, for example, due to excessively high gains of exciters or inadequately tuned power system stabilizers. Additional errors which may be difficult to identify are also expected to exist in the data base. These errors can lead to incorrect study results. In these cases, oscillations and criteria violations observed in dynamic stability simulations, are results of model errors, and they are not indicators of the problems in the system performance. On the other hand, these errors can result in failing to show oscillations and criteria violations that could occur if the models were accurate.

### Missing models of collector systems and step-up transformer for solar and wind farms

In the power flow cases, some solar PV or wind power plants are modeled as one or several aggregated units connected to a high voltage bus at the Point of Interconnection. At the same time, collector systems and step-up transformers between individual units and the collector system, and between the collector system and high voltage buses are not modeled. Such simplified modeling may provide inaccurate results in voltage stability, as well as in dynamic stability studies.

Figure 6.4-3 illustrates a schematic of a collector system of a wind farm or solar photovoltaic plant and Figure 6.2-4 shows a correct equivalent model of such generation project.

Figure 6.4-3: Configuration of a Wind Farm (or solar PV plant)

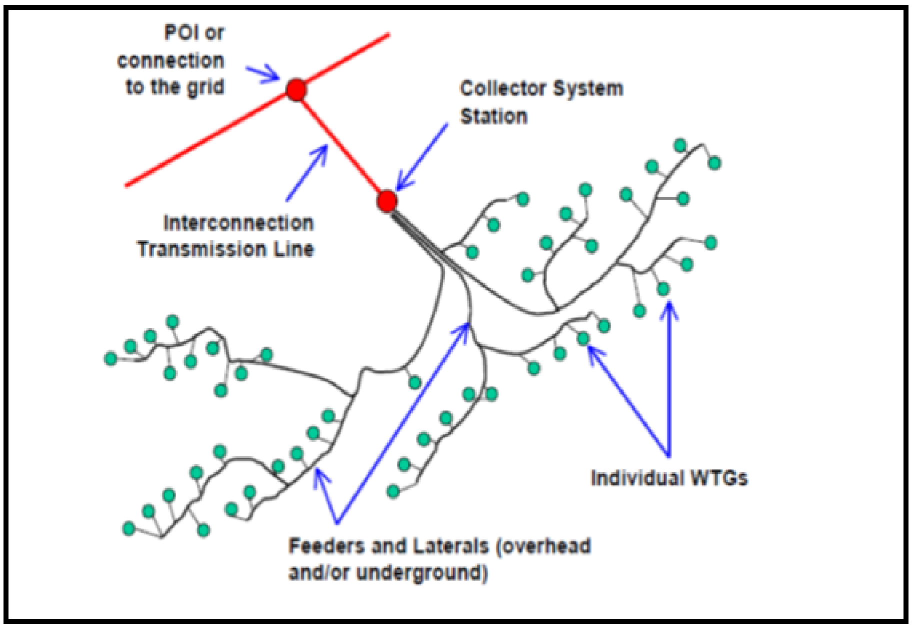
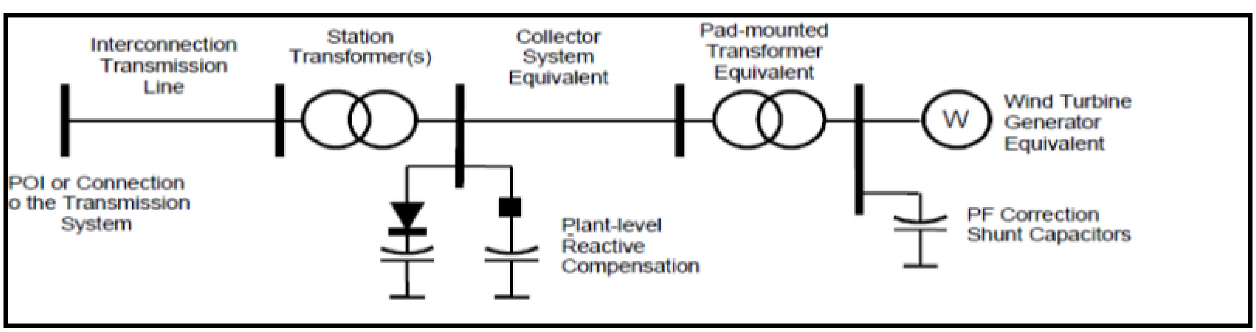



Figure 6.4-4: Equivalent model of a wind farm or solar PV plant for use in power flow and dynamic stability studies.



**Inadequate models of frequency response**

The frequency response studies performed by the ISO showed higher frequency response from the ISO than what was actually observed during disturbances. The reasons for these discrepancies may be, among others, blocked governors on some units that are not modeled as blocked in the simulations, errors in governor models when the models show higher response than the response during actual disturbances, or actual governor withdrawal that is not reflected in the models.

**Mismatch between simulation results and real-time measurements**

Since the studies and real time measurements showed discrepancies in the system performance, especially in the generation output, these discrepancies need to be investigated. More detailed analysis of the measurements and the simulation results will promote more accurate models.

### 6.4.4 Generator Modeling Upgrades and Validation Study – 2016-2017

The ISO's Generator Modeling Upgrades and Validation Study was scoped and initiated in the 2016-217 transmission planning process to address the modeling issues identified above, and the studies of the 2016-2017 transmission planning process therefore concentrated on the modeling issues rather than on frequency response studies.

The following goals were developed for this Generator Modeling Upgrades and Validation Study:

- identify missing models or missing model components
- identify models that have deficiencies and require upgrades
- point to generators that are modeled with generic models with typical parameters and obtain more accurate models of the units

The models that have deficiencies would be identified by comparison of the real time measurements and the simulation results. Where real time measurements are not available, model deficiencies would be identified based on assessments of unrealistic performance of the models in the dynamic stability simulations.

The ISO would work with the PTOs who in turn would contact generation owners, and request that they provide modeling data updates. The updated models will be tested in dynamic stability simulations and compared with the real-time measurements.

### 6.4.5 2016-2017 Progress

#### 6.4.5.1 *Model Validation with the WECC Dynamic Stability Masterfile*

The ISO reviewed the ISO portion of the WECC Dynamic Stability Masterfile, which is the database containing dynamic stability models of all WECC existing and future generation units. Generators with missing models or models that needed updates were identified.

This list included missing or seemingly incorrect models identified from the review of the Masterfile and also the models that caused issues in the dynamic stability studies previously performed by the ISO. The list of missing models included models of the components that were not represented in the Masterfile, for example, excitation systems of synchronous machines, control systems of inverter-based generation, speed governors of synchronous generators, or protection relays on both synchronous and inverter-based units.

The models that needed updates included the following:

- Generators represented in the Masterfile according to the ISO knowledge as a wrong type, for example, wind farms modeled as thermal units, or existing wind plants modeled not as the their actual type, such as induction generators modeled as inverter-based, and also solar plants modeled as wind and vice versa,
- Existing generators modeled with typical generic parameters instead of being modeled with parameters based on testing,
- Generators modeled with obsolete models that are not used and not approved by WECC anymore, and,
- Models with parameters that needed to be checked, such as models of control systems of the inverters and renewable projects that had conflicting control settings, or models of excitation systems with unusually high gains, or governors of the synchronous machines with unusually high or low droop settings, or conflicting parameters of the synchronous generators' saturation.

Other dynamic stability models included in the list of the models that seemed to be incorrect were the ones that showed unexpected performance in dynamic stability simulations previously performed by the ISO. These models included governors that showed unusually high frequency response, control systems of the renewable generation that showed spikes in voltage or frequency and as a result were tripped by frequency or voltage protection, and also models that were the cause of undamped oscillations with faults where such oscillations were not expected.

The ISO sent the list of generators that had missing models or models that needed updates to the PTOs with the explanations of what was missing and which data seemed to be incorrect. The ISO initially identified more than 400 generators with suspicious dynamic model. In coordination with the PTOs, the list was reduced as some generating units have retired or been canceled.

The ISO then worked with the PTO's on contacting generator owners to address the identified issues. According to the Standard MOD-032, generation owners have 90 days to respond. The ISO and PTOs have received responses from many generation owners, but are still working with most of them to obtain the requested data.

#### 6.4.5.2 *Model Validation with Online Dynamic Security Assessment*

The ISO is involved in a continuous model validation effort using real-time snapshots from ISO's online DSA (Dynamic Security Assessment). Voltage, frequencies and flows are compared with those observed in PMU and SCADA data. Model validation efforts have led to correction of baseload flags in the input dynamic data for DSA and modification of initialization rules to accommodate wind and solar models that are at very low or zero output in the state estimation solutions. Model validation is a continuous effort that is being conducted in collaboration with Peak Reliability.

The ISO also performed dynamic stability analysis of the disturbance that occurred on March 3, 2016 that caused the WECC–wide frequency to drop to about 59.84Hz.

The simulation results generally matched the measurements. The simulated frequency nadir was higher than the measured, which indicates that the simulated frequency response of the generators is too optimistic. Due to lack of measurements at generating plants, it could not be determined which generator models cause the discrepancy between the simulation and actual performance. The results demonstrated the need to perform field testing to verify generator dynamic models, and installing PMUs at the generating plant would greatly improve the model validation.

The work on the model validation using the March 3, 2016 disturbance continued in the 2017-2018 TPP cycle.

#### 6.4.5.3 *Conclusions drawn in 2016-2017 Cycle*

*From the work performed by the ISO on the update and validation of dynamic stability models, the following conclusions were made.*

- Due to the discrepancies between dynamic stability simulations and actual system performance, dynamic stability models need to be updated and validated.
- The ISO identified many models that need updating and is working with the PTOs on the update of the models
- Not having PMU with high resolution on the generating plants appears to be a significant obstacle in validating dynamic stability models and in obtaining correct models. Installing more PMUs will improve the validation process.
- The ISO needs to continue the work on model validation and on updating dynamic stability models.

### 6.4.6 2017-2018 Progress and Concerns:

6.4.6.1 Work with Transmission Owners on Models Update

The ISO has continued to work with Transmission Owners to collect the needed information from generators, and this effort has raised a number of challenges. The various standards requirements obligating the provision of validated data are complex:

- NERC requires all generators connected to the Bulk Electric System and greater than 20 MVA (single unit) or 75 MVA (generating plant) comply with NERC data standards, and provide updated data at least every 10 years. However the NERC dynamic data validation standards only apply to generating units that are greater than 75 MVA, which appears to capture about 80% of grid-connected generation in the ISO footprint.
- The WECC generating unit validation policy applies to generators greater than 10 MVA, which would address a further 17%.
- The ISO also has certain tariff rights to generator information, but limited mechanisms to ensure compliance for those that are not NERC-jurisdictional.

The ISO and PTOs are actively requesting validated modeling data from all generators. Of 177 letters sent to generators thus far, 130 have replied and many with the intention to provide data but very few provided completed sets of validated data, generally citing validation cost concerns. For the NERC-jurisdictional generators, the ISO and the PTOs will continue to work with them while also stressing the need for the generators to comply with NERC mandatory standards.

For the non-NERC-jurisdictional generators, the ISO will continue to prioritize particular generators that are perceived to pose particular concern, and will also be moving in 2018 to improve its tariff framework for ensuring compliance with tariff provisions for data collection through a stakeholder process and subsequent tariff modifications.

#### 6.4.6.2 Work on Model Validation Process

In 2017, the ISO transmission planning department performed the following activities related to the NERC MOD-033-1 model validation process:

- Worked with Peak RC to obtain a list of major disturbance events that occurred within the WECC in the previous year;
- Selected an event to be studied as part of the MOD-033-1 validation process (a March 3, 2016 event was selected for the study) and continued the work started in the 2016-2017 cycle on analysis of this event;
- Obtained power flow and dynamic data related to the abovementioned event from the Peak RC and the WECC for the study;
- Performed power flow and transient stability study to validate power flow and dynamic models.

During the contingency event of March 3, 2016, two 500 kV transmission lines in Northwest: Ashe-Slatt and Buckley-Slatt tripped. Remedial Action Scheme tripped 1491 MW of generation in Northwest after the outage of the second line. BPA RAS also inserted reactive support and worked as designed. About 28 seconds after the Northwest generation was tripped, two Navajo generation units in Arizona also tripped due to a different reason.

Comparison of the simulation results and actual measurement during the March 3, 2016 event showed that the models still need improvement. The comparison of the simulation and measurements is shown in Figure 6.4-5 through Figure 6.4-7. These results are preliminary, and the ISO continues its work on studies and model validation during the March 3, 2016 contingency.

Figure 6.4-5 Voltage on the Devers 500 kV Substation during the March 3, 2016 contingency event

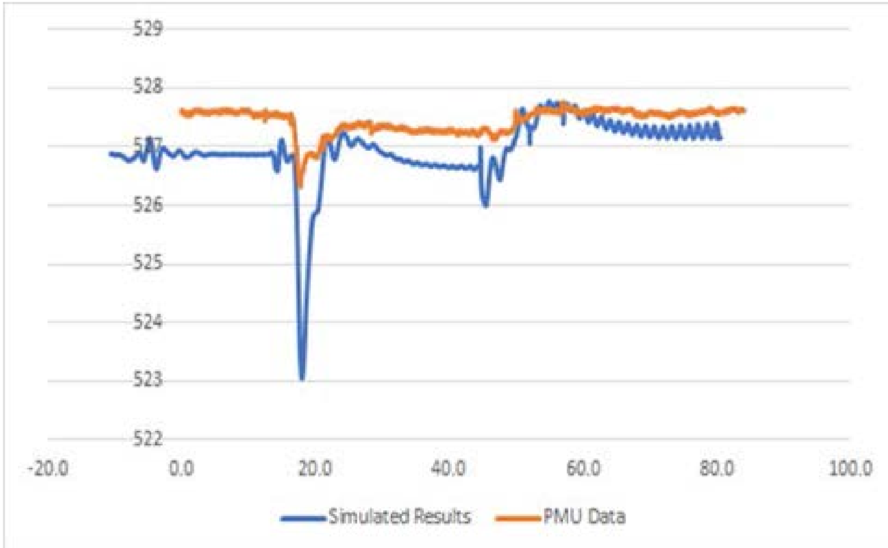



Figure 6.4-6 Frequency on the Devers 500 kV Substation during the March 3, 2016 contingency event

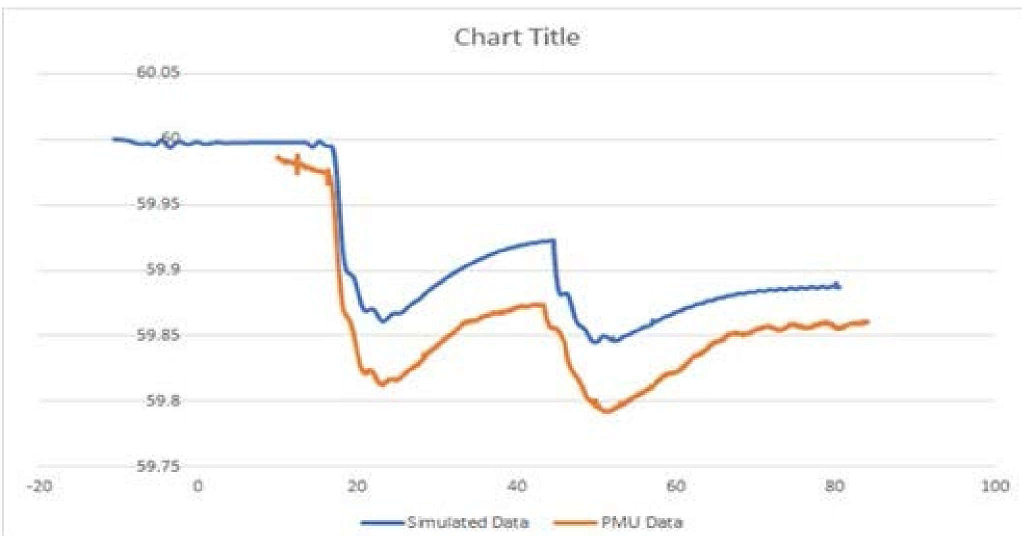
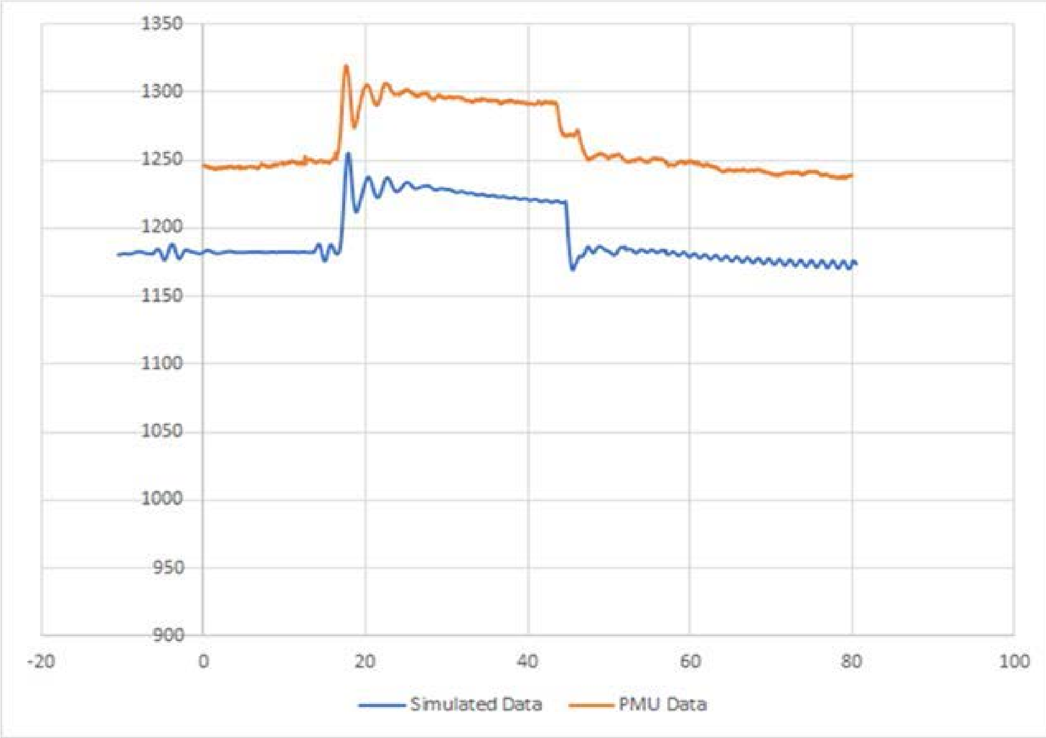


Figure 6.4-7 Devers – Valley 500kV total line flow (2 lines) during the March 3, 2016 contingency event




In addition to the above efforts, the ISO reviewed the data obtained from the phasor measurement units that are installed within the ISO Balancing Authority Area. The ISO proposed, at the transmission planning stakeholder meeting on November 16, 2017, that PMUs be added to all ISO intertie transmission faculties to other balancing areas to demonstrate compliance with the NERC Reliability Standard BAL-003-1.1, which requires that the ISO must meet frequency response obligation based on net actual interchange measurements. The ISO's median score in response to NERC designated frequency events for the compliance year must meet or exceed its frequency response obligation.

In addition to the above proposal, the ISO also reviewed the PMU data quality and its availability. Further discussions are on-going in an effort to improve the PMU network bandwidth.

### 6.4.6.1 *Next steps:*

*Efforts will continue to collect modeling data. After all the responses from the generation owners are received, the dynamic database will be updated. The ISO and the PTOs will perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance. After the models are validated, they will be sent to WECC so that the WECC Dynamic Masterfile can be updated, and the updated models will be used in the future.*

*Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.*

*Further work will also investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.*

## 6.5 Gas/Electric Coordination Special Study

### 6.5.1 Gas/Electric Coordination Transmission Planning Studies for Southern California

In 2017, the ISO participated in the CPUC's Order Instituting Investigation (OII) to determine the feasibility of minimizing or eliminating the use of Southern California Gas Company (SoCal Gas)'s Aliso Canyon natural gas storage facility while still maintaining energy and electric reliability for the Los Angeles Basin. The CPUC opened the Aliso Canyon OII proceeding (I.17-02-002) on February 9, 2017 in compliance with Senate Bill 380.[117]

The purpose of the proceeding is to examine the long-term viability of the Aliso Canyon gas storage facility. The scope of the proceeding is to perform studies to determine the long-term feasibility of minimizing or eliminating the use of the facility while still maintaining energy and electric reliability for the Los Angeles region, consistent with maintaining just and reasonable rates.

The Senate Bill 380 required the CPUC to open this proceeding no later than July 1, 2017, and to consult with the State Energy Resources Conservation and Development Commission, the California Independent System Operator, the local publicly owned utilities that rely on natural gas for electricity generation, the Division of Oil Gas and Geothermal Resources in the Department of Conservation (DOGGR), and relevant government entities, and others in making its determination.

On June 26, 2017, the CPUC posted the Proposed Scenarios Framework for the Aliso Canyon OII proceeding.[118] In its proposal, the CPUC Energy Division plans to undertake three studies to inform the investigation: hydraulic modeling, production cost modeling, and economic modeling. The studies are intended to estimate how reducing or eliminating use of Aliso Canyon gas storage would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs, respectively. Each model will be run independently of the others (i.e. with its own inputs and outputs un-connected to the others), with the exception of having the production cost model output of time series profiles of natural gas usage at the gas-fired power plants. This profile of natural gas usage will be an input to the hydraulic modeling.

The ISO provided comments[119] to the CPUC regarding the proposed studies on March 13, 2017, supporting the Energy Division staff's considerable efforts in preparing the Scenarios Framework. The ISO's comments primarily focus on the Commission's proposed production cost modeling

[117] CPUC News Release "CPUC to Consider Future of Aliso Canyon Natural Gas Storage Facility," February 9, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M175/K467/175467112.PDF.

[118] "Proposed Scenarios Framework: I.17-02-002," issued as *Attachment A* to the "Administrative Law Judge's Ruling Requesting Informal Feedback on Energy Division's Initial Proposed Phase 1 Scenarios and Noticing Workshop, CPUC Proceeding No. I.17-02-002, June 26, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M191/K054/191054394.PDF (Scenarios Framework).

[119] "Informal Comments of the California Independent System Operator Corporation," CPUC Proceeding No. I.17-02-002, July 24, 2017, available from the CPUC's website at http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Version1Comments_CAISO.pdf, also available from the ISO's website http://www.caiso.com/Documents/Jul24_2017_InformalComments-ProposedScenariosFramework-AlisoCanyonNaturalGasStorageFacility_I17-02-002.pdf.

analysis, which is capable of modeling hourly electric grid operations performance of the gas-fired generating facilities. In addition, the ISO provided suggestions regarding how the Commission should incorporate the ISO's power flow modeling results into the Commission's production cost modeling analysis. The Scenarios Framework indicates that Commission's proposed production cost modeling will be conducted with a "bubble-type" model "where geographic granularities inside bubbles are not enforced as they are in the power flow simulations used for transmission planning."[120] The ISO understands this limitation in the production cost modeling, but maintains that there are local reliability requirements and transmission constrains that must be recognized in the production cost modeling. As a result, the ISO recommended that the Commission use ISO power flow studies as inputs into the production cost modeling to capture local requirements and transmission constraints. The ISO proposed to conduct power flow modeling and make the assessments and results available for the Commission to incorporate into its production cost modeling analysis. The results from both the LCR and the bulk transmission reliability assessments should be used as inputs for minimum generation requirements in the production cost modeling study. The minimum generation requirements in the LA Basin and San Diego areas should be modeled as nomograms in the production cost modeling study. The ISO has reached out to LADWP for future collaboration on power flow analyses as the study area encompasses both the ISO and LADWP Balancing Authority Areas.

The CPUC held the first workshop for the Aliso Canyon OII on August 1, 2017 in Los Angeles.[121] At this workshop, the Commission presented high-level study scopes for the production cost, hydraulic and economic modeling. The next workshop is yet to be scheduled, pending the Commission finding and retaining consultants needed for the hydraulic and economic modeling.

**Joint-agency Reports on Aliso Canyon Risk Seasonal Reliability Assessments**

In 2017, the staff from the Aliso Canyon Technical Assessment Group from the CPUC, CEC, ISO and LADWP, with inputs from SoCal Gas Company, prepared two seasonal reliability assessment reports related to Aliso Canyon gas storage unavailability risk: the Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment[122] and the Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement.[123]

Mitigation measures[124] developed during the 2016-2017 winter and the 2016 summer improved the outlook for energy reliability for the 2017 summer. The measures included changing the gas balancing rules to encourage customers to buy natural gas to meet their demand on a daily basis

[120] Scenarios Framework, at p. 9.

[121] "Event Details," from the CPUC's website http://cpuc.ca.gov/calEvent.aspx?id=6442454005.

[122] "Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment," CEC Docket No. 17-IERP-11, May 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217639_20170519T104800_Aliso_Canyon_Risk_Assessment_Technical_Report_Summer_2017_Asses.pdf.

[123] "Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement," CEC Docket No. 17-IERP-11, November 28, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221863_20171128T103411_Aliso_Canyon_Winter_Risk_Assesment_Technical_Report_201718_Supp.pdf.

[124] "Aliso Canyon Mitigation Measures," CEC Docket No. 17-IERP-11, May 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217640_20170519T104801_Aliso_Canyon_Mitigation_Measures__May_19_2017.pdf.

rather than relying on gas storage, the possible use of existing natural gas at Aliso Canyon, operational coordination, customer conservation, and identifying steps to increase gas supply.[125]

Initial 2017-2018 winter assessment indicated curtailment risk to noncore gas customers would be higher than the previous 2016-2017 winter assessment due to three major gas transmission line outages (i.e., Line 3000, Line 4000, Line 235-2) that reduced firm receipt into the Northern Zone from 1590 mmcfd to 550 mmcfd. However, on January 9, 2018, the inter-agency Aliso Canyon Technical Assessment Group posted an updated "Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement: January Situational Update".[126] The updated report indicated that with November's warm temperatures continuing throughout December, SoCalGas continued to be able to serve a large portion of demand using receipts of pipeline gas instead of relying on gas from underground storage. The updated report concluded that with the warm conditions experienced in November and December that have significantly contributed to SoCalGas avoiding the need to withdraw the quantities of gas it would in a normal (i.e., cold) temperature winter. Furthermore, assuming no additional gas system or electric transmission system outages and full gas supplies would arrive at the pipeline receipt points, the concern that SoCalGas would need to curtail natural gas service to noncore customers in December 2017 was considered to be moot and the risk of gas service curtailments in January 2018 appears to be significantly reduced.

Moving forward, the ISO will continue to participate and to provide support to the CPUC in the Aliso Canyon OII process by participating in future workshops after the CPUC selects the consultants for the hydraulic and economic modeling and study. The ISO will support the CPUC OII process by providing the results of the power flow study for inputs to the CPUC's production cost model. The ISO will also engage and collaborate with LADWP on the power flow study case development, as well as the study as the impacted area encompasses both the ISO and LADWP's balancing authority areas.

### 6.5.2 Northern California Gas-Electric Coordination

Based on the previous transmission planning cycle's assessment comparing forecasted gas demand and gas facility capacities, the gas system in Northern California seems to have adequate capacity to supply peak winter and summer forecasted demands under both normal and plausible constrained conditions. The high capacity doubly built backbone pipelines and storage facilities – which are scattered but located close to the backbone pipelines - add redundancy and flexibility in supplying gas to power plants in the area. The assessment based on local capacity requirements for critical local capacity areas and its dependency on local thermal fleet for meeting LCR identified all critical local capacity areas, except for the Pease subarea, with no significant risk of not meeting its local capacity requirement due to plausible gas constrained conditions. The ISO will continue to work with the PG&E gas operation group and other stakeholders in future

[125] The CPUC issued a directive on May 8, 2017 to SoCalGas to increase storage injections to the Honor Rancho and La Goleta storage fields to maintain reliable delivery to customers during peak summer days, available at https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5208-A.pdf.

[126] "Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement: January Situational Update," CEC Docket No. 17-IERP-11, January 8, 2018, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN222118_20180109T094720_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report_201718_Sup.pdf.

cycles to identify plausible gas constrained condition, including the impact of new DOGGR regulation that could significantly impact generation from gas-fired power plants in Northern California. To the point such conditions are identified, the ISO will perform studies to identify if such conditions impose any adverse impact to electric system reliability.

## 6.6 Characteristics of Slow Response Local Capacity Resources

This section provides a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs. While the emphasis has been on meeting the needs in local capacity areas, the ISO considers preferred resources as possible mitigations for reliability issues across the ISO footprint, not just in local capacity areas that have already been identified and included in the CPUC's resource adequacy processes. In that context, the ISO believes that there needs to be broader consideration of stakeholder consultation, development of methodologies as opposed to "absolute" metrics, and incorporation of those methodologies into other assessment frameworks.

Thus, the ISO's study efforts on this issue began as a special study in the 2016-2017 planning cycle to consider the viability of these resources, and those efforts have transitioned into joint industry and CPUC efforts that will ultimately need to be enshrined in other processes such as the CPUC's Resource Adequacy proceeding and ISO-documented methodologies for assessing preferred resources in transmission planning assessments and local capacity technical studies. As these assessment methodologies have coalesced, therefore, the ISO expects that future ISO documentation of slow response local capacity resources will be captured in preferred resource assessment methodologies and annual study plans rather than through special study documentation.

While the ISO considers that the methodology for establishing characteristics in local capacity areas has been adequately designed, implementation details on how the resources will be accessed through market and dispatch operation remain to be finalized.

### 6.6.1 Background

Historically, the necessary characteristics for demand response resources to meet local capacity performance requirements had not been consistently applied across the industry. Over the last several years, especially stemming from the more detailed analysis in addressing the early retirement of the San Onofre Nuclear Generating Station, a more urgent need arose for greater alignment between reliability requirements, the procurement rules for local resource adequacy capacity developed by the CPUC, and how the ISO can rely on demand response resources to meet reliability requirements and comply with NERC mandatory standards. This was especially true for energy-limited slow-response resources – those resources that cannot respond quickly enough after a contingency to allow the ISO to prepare the system for the next contingency – and how the ISO can plan and operate these resources to meet NERC mandatory standards.

Stemming from stakeholder concerns expressed with the changes the ISO proposed to the ISO's business practice manual for reliability requirements (PRR854) to provide greater clarity on current technical needs, the ISO initiated a new stakeholder process to address implementation issues and outstanding stakeholder questions related to the pre-contingency dispatch of resources for local reliability needs, and provide broader visibility of the analysis being conducted inside the transmission planning process that was already underway.

ISO staff were encouraged to focus on developing creative solutions to allow energy-limited, slower responding demand response resources to count toward local capacity requirements by enabling the ISO to use the resources prior to a first contingency, rather than relying only on those resources capable of fast response after a first contingency event.

As part of this new stakeholder process, the ISO conducted a series of joint workshops with the CPUC to address how energy-limited, slow response demand response resources can help the ISO effectively address NERC, WECC and ISO reliability standards applicable to local areas. The ISO encouraged participation from all stakeholders involved, and believes that collaboration with the CPUC is fundamental to advancing our shared interests in integrating preferred resources and ensuring electric system reliability.

As noted earlier, the stakeholder process was expected to rely on and carry forward with the special study work to examine resource requirements already underway as part of this special study being conducted in the 2016-2017 transmission planning process. The ISO conducted a conference call on April 26, 2016 to begin scoping the technical study work necessary to establish energy requirements for resources dispatched pre-contingency for local reliability requirements. The preliminary results were presented at a joint ISO/CPUC workshop on October 3, 2016 and in the transmission planning process stakeholder session 2 held on September 21st and 22nd, 2016. The ISO received comments that identified the need for additional analysis. In particular, the IOUs raised concerns with the methodology they employed to scale their load shapes.

In the 2016-2017 Transmission Plan, the ISO documented the preliminary results presented in those sessions 2016 stakeholder events, and the ISO carried on with additional coordination and analysis that culminated in revised methodologies and results presented at a joint ISO-CPUC workshop on October 4, 2017.

### 6.6.2 How Slow Response Resources can help meet Local Capacity Needs

Local capacity resources must enable the ISO to readjust the system within 30 minutes following a first contingency to prepare the system for a potential second contingency pursuant to Section 40.3.1.1(1) of the ISO tariff, California ISO Planning Standards and NERC standards for stability limits. Resources can provide this capability by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and re-dispatch resources to effectively reposition the system within 30 minutes after the first contingency as illustrated in Figure 6.6-1 or (2) having sufficient energy available for frequent dispatch on a pre-Contingency basis to ensure the operator can meet minimum online commitment constraints to reposition the system within 30 minutes after the first contingency occurs as illustrated in Figure 6.6-2. The number of dispatches in the latter case is anticipated to be materially higher than in the former case.

Figure 6.6-1: Post-contingency Dispatch of Fast-response Resources

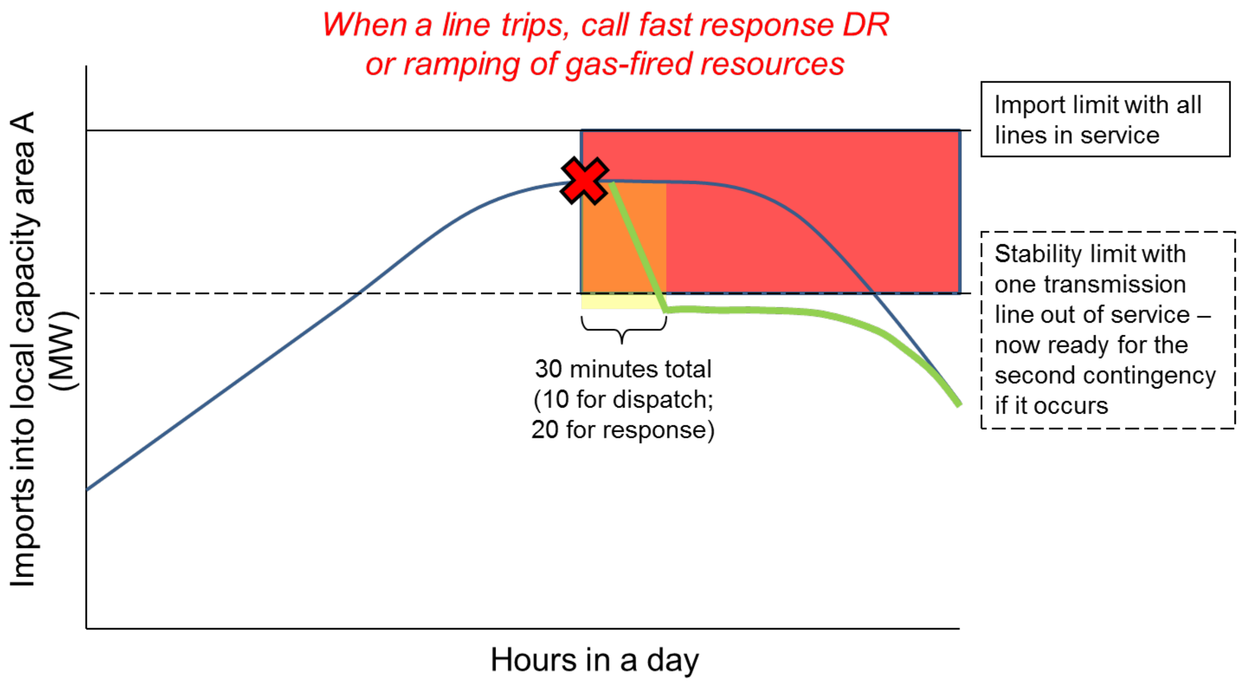
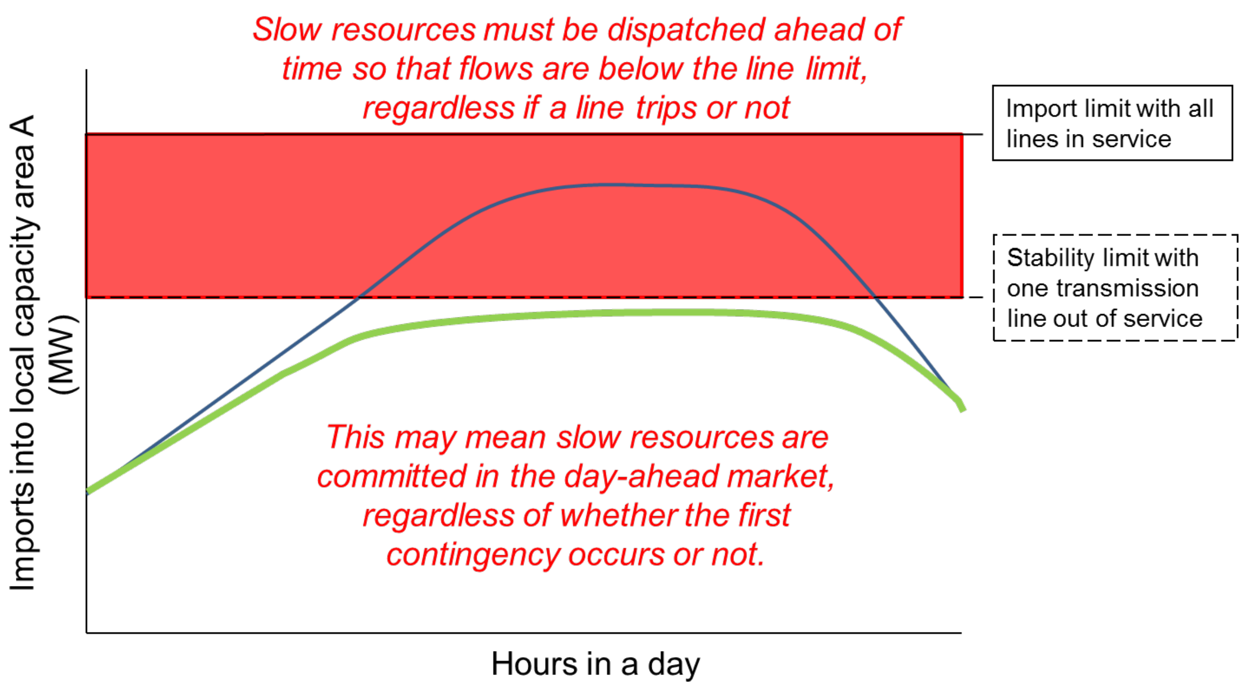



Figure 6.6-2: Pre-contingency dispatch of slow-response resources



The ISO's studies examine the required availability for slower response resources to be considered for local resource adequacy on the basis of pre-contingency dispatch. While the studies also evaluated increased amounts of generic slow-response resources, the initial focus of the ISO studies was on existing slow-response demand response (DR) resources.

The availability characteristics evaluated are based on the characteristics of existing slow-response DR programs and include:

- Annual, monthly and daily event hours;
- Number of events per month, day and consecutive days; and,
- Operating times (time of year, days of the week, hours of the day, etc.)

The ISO's study methodology does not consider other factors that could require upward availability adjustments to the requirements for local reliability resources, and it is expected that these, if necessary, will be addressed directly by the utility/PTO such as responses to:

- Prices or triggers other than local capacity related reliability events
- System events or by PTOs for distribution system issues
- Planned outages and unforeseen events

### 6.6.3 Demand response participation in the ISO market and operations

The ISO has introduced two products to enable wholesale demand response resource participation in the ISO market and operations. Reliability Demand Response Resource (RDRR) allows emergency responsive demand response resources to integrate into the ISO market. Proxy Demand Resource (PDR) participates in the ISO comparable to a supply resource. Table 6.6-1 provides some of the characteristics of RDRR and PDR that are relevant to how these resources are considered in this study.

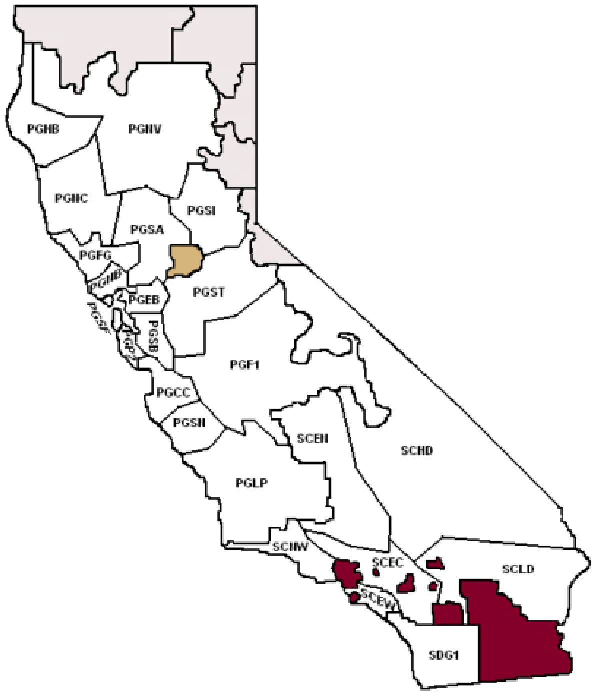
Table 6.6-1: RDRR and PDR characteristics

| Market model | Services | Market dispatch | Maximum response time | Maximum run time | Minimum availability (for reliability-only use) |
|---|---|---|---|---|---|
| RDRR | Energy | Economic day-ahead, reliability real-time (any remaining uncommitted capacity) | ≤ 40 minutes | >4 hours | 15 events and /or 48 hours per term[127] (June –September & October – May) |
| PDR | Energy, non-spin, residual unit commitment (RUC) | Economic day-ahead and real-time | N/A | N/A | N/A |

Demand response resource aggregations are required to be within a single sub-Load Aggregation Point (LAP) which were developed initially for congestion revenue rights (CRRs). A sub-LAP is an ISO-defined subset of pricing nodes (Pnodes) within a default LAP. The 24 sub-LAPs shown in Figure 6.6-3 were created to reflect major transmission constraints within each utility service territory. Each sub-LAP is designed to fall entirely within a single Local Capacity Area (LCA). However, multiple sub-LAPs can reside within a LCA which may not be aligned with local capacity sub-areas.

[127] Economic participation of RDRR in the day-ahead market will not reduce availability limits for the term. Real-time RDRR dispatches in the event of imminent or actual system or transmission emergency are counted against total RDRR eligible availability limits.

Figure 6.6-3: Sub-LAPS




Note that the sub-laps were updated on January 1, 2017 and restructured into 25 sub-laps as of January 1, 2017.

### 6.6.4 Study Methodology and Assumptions

The initial methodology developed in the 2016-2017 cycle is documented below.

The following changes were subsequently identified and presented at a joint ISO-CPUC workshop[128] held on October 4, 2017, that together with the initial methodology represent the final methodology:

- Hourly load scaling method changed. Only five days around the peak are now scaled to CEC 1-in-10 forecast. Remaining 360 days are scaled to 1-in-2.
- 2013 recorded data was replaced with 2016 data (SCE & SDGE).
- SDG&E existing slow-response DR amount updated from 10 MW to 52 MW. Increased scenarios studied to include 2 percent, 5 percent and 10 percent of peak.
- ISO Step 2 analysis performed for the 5 percent scenario in addition to 2 percent scenario.

[128] Slow Response Local Capacity Resource Assessment," CAISO-CPUC Joint Workshop, October 4, 2017 (updated October 11, 2017), available on the ISO's website at http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

- Refined ISO Step 2 power flow analysis, i.e. reduced reactive power capability proportionally when reducing active power output of a generator.

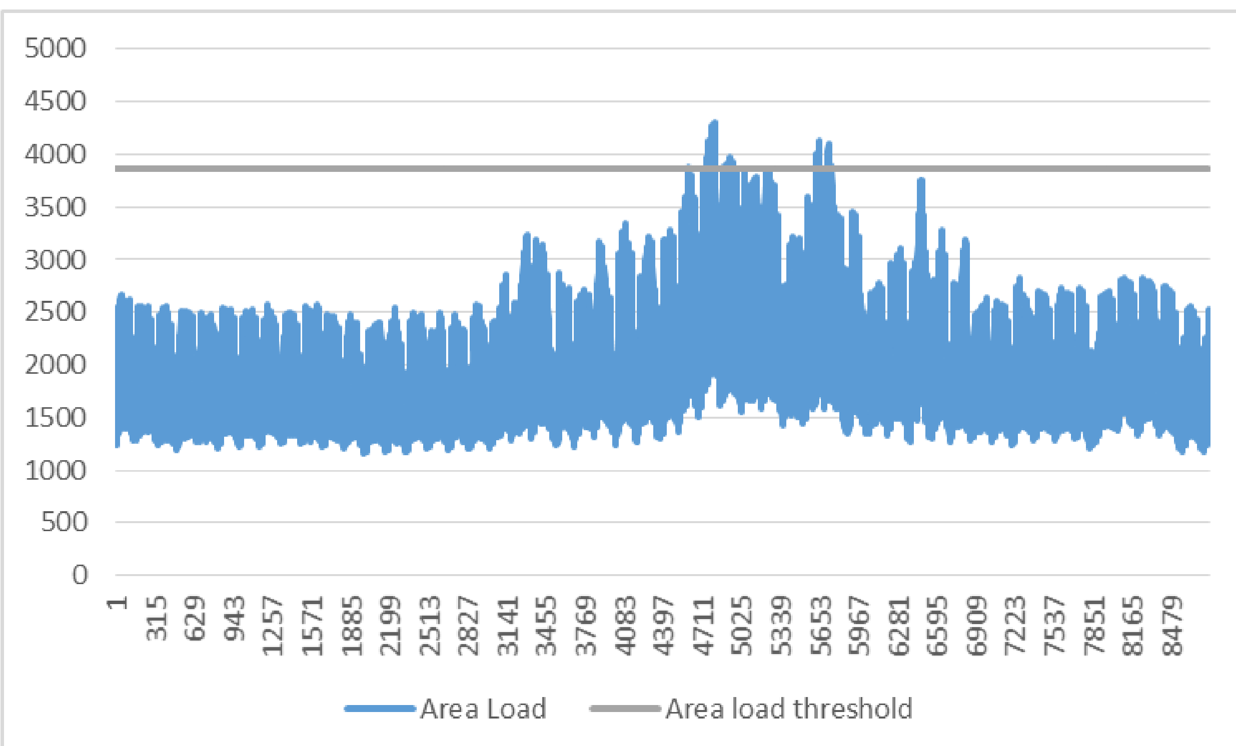
**2016-2017 Methodology**

The basic study methodology involves determining an area load threshold, which is shown as a grey line in Figure 6.6-4 which slow-response local capacity resources must be dispatched to maintain reliability of the transmission system, and then identifying the hours where the forecast hourly load, which is shown in blue, exceeds the threshold.

**Study steps**

- Develop hourly forecast load data for the LCR area or sub-area under consideration
- Determine the area load threshold as described below
- Using a spreadsheet, identify instances where the forecast hourly load for the area exceeds the area load threshold obtained in step 2 and record relevant data.
- Repeat the above steps for the slow-response resource amounts and study areas to be assessed

Figure 6.6-4: Study Methodology



### Determination of area load threshold

Two approaches were identified to determine the area load threshold. The first approach ("Step 1") is a simplified approach which assumes active power from all resources within the study area are equally effective and neglects reactive power capability impacts. In this approach the area load threshold is calculated as the difference between the forecast area peak load and the slow response resource amount.

The second approach ("Step 2") tests locational and reactive power impacts and is more reliable compared to Method 1 in particular for voltage stability limited areas. In this approach the area load threshold is determined as follows:

- Starting from the final marginal LCR base case for the study area reduce online generation in the LCR area by the amount of slow response resource
- Apply the limiting contingency, which should cause loading, voltage, etc. violation
- Reduce area load proportionally until the loading, voltage, etc. is acceptable. Record the resulting area load as the area load threshold.

### Assumptions

The study methodology assumes:

- Slow-response resources are called last and therefore have the lightest possible duty.
- Slow response resources that are the subject of this study will not be utilized for events beyond the planning standards such as unavailability of multiple generating units which can occur during non-peak load hours.
- Demand response capacity value is assumed to be constant throughout the 8760 hours of the year.
- Perfect forecast and dispatch capabilities to call resources only when and where they are needed.
- DR availability in not impacted by dispatch frequency.
- The local area or sub-area is not resource-deficient.

The study assesses dispatch calls related to local resource adequacy and does not account for other non-coincident uses such as:

- In response to price or triggers other than local capacity related reliability events
- For system events or by PTOs for distribution system issues
- Due to planned outages and unforeseen events
- For program evaluation

### Projected hourly load data

Going forward, hourly load data will take into account the new CEC hourly load forecasting data to the greatest extent possible.

For the initial methodology developed for 2017, hourly load data for each local capacity study area for year 2017 was developed by the respective load serving entity (LSE) from recorded hourly load data for the area. In the absence of better hourly load forecast, hourly load values for 2017 were obtained by multiplying recorded load for the hour by the ratio of the 2017 forecast 1-in-10 peak load to the recorded peak load for the historical year. Three sets of 2017 hourly data produced using recorded data for 2013 to 2015 were used in the study.

This approach has the following shortcomings:

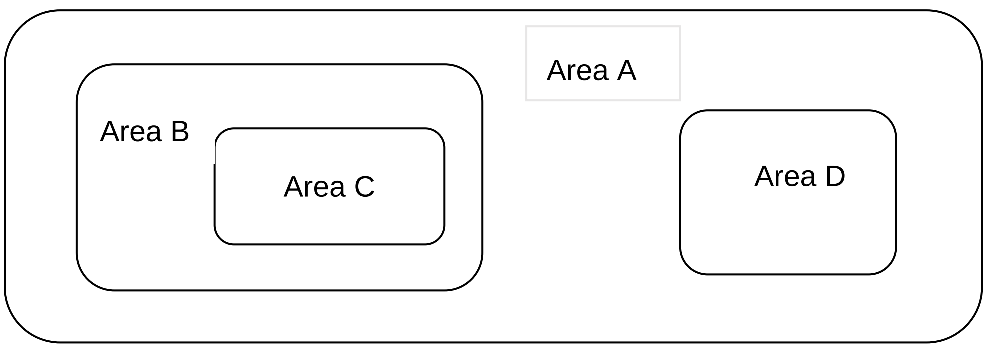
- All load hours are scaled in proportion to the forecast 1-in-10 peak load.
- Since the forecast is based on simply scaling historical load profiles, it does not capture future changes in load shape due to increasing DER such as BTM PV.

The study may be updated when improved hourly forecasts are available.

**Non-coincident dispatch calls among overlapping areas**

A resource located in a sub-area can be called to address local capacity need in the sub-area or in overlapping areas. Non-coincident calls in overlapping areas must be included in the sub-area results. For example in Figure 6.6-5 below non-coincident dispatch calls for Area A and Area B must be included in the results for Area C in addition to dispatch calls for Area C itself. Similarly, non-coincident calls for Area A must be included in the results for Area B and Area C.

Figure 6.6-5: Dispatch calls in overlapping areas




**Local capacity areas and resource amounts assessed**

Table 6.6-2 summarizes the local capacity areas and resource amounts assessed. The study areas were selected by the respective LSE. The ISO expects availability studies will be performed for those local capacity areas and sub-areas not covered by the current study before slow-response DR and other similarly use-limited resources can be counted for local resource adequacy in those areas. In addition to current slow-response DR amounts, additional amounts of generic slow-response resources were studied as shown as a percentage of study area load.

Table 6.6-2: Local Capacity Areas and Resource Amounts to Consider

| **Load Serving Entity** | **Areas studied** | **Slow-response resource amounts to consider** |
|---|---|---|
| | Method 1 | |
| SCE | - All LCAs,<br>- All sub-areas | - Existing DR (Slow Response)<br>- 2% of study area load<br>- 5% of study area load<br>- 10% of study area load |
| PG&E | - All LCAs | - Existing DR (Slow Response)<br>- 2% of study area load<br>- 5% of study area load<br>- 10% of study area load |
| SDG&E | - San Diego sub-area | - Existing DR (Slow Response)<br>- 1% of study area load<br>- 3% of study area load |
| | Method 2 | |
| ISO | - Main local capacity areas and voltage stability limited sub-areas in southern California | - Existing DR (Slow Response) |

**Conclusions from 2017-2018 Analysis Effort**

From the analysis and results conducted in the 2017-2018 planning cycle, the methodology and preliminary results for assessing the characteristics of slow response local capacity resources have been reasonably determined, which will be incorporated into future reliability analyses.

Implementation issues will continue to be addressed through other processes outside of the transmission planning process.

# Chapter 7

# 7 Transmission Project List

## 7.1 Transmission Project Updates

Table 7.1-1 and Table 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 | Expected In-Service Date |
|---|---|---|---|
| 1 | Estrella Substation Project | NEET West | May-19 |
| 2 | Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor | PG&E | Canceled |
| 3 | Borden 230 kV Voltage Support | PG&E | Feb-19 |
| 4 | Caruthers – Kingsburg 70 kV Line Reconductor | PG&E | Canceled |
| 5 | Cascade 115/60 kV No.2 Transformer Project and Cascade – Benton 60 kV Line Project | PG&E | Jul-20 |
| 6 | Cayucos 70 kV Shunt Capacitor | PG&E | Canceled |
| 7 | Christie 115/60 kV Transformer No. 2 | PG&E | Completed |
| 8 | Clear Lake 60 kV System Reinforcement | PG&E | Dec-22 |
| 9 | Contra Costa Sub 230 kV Switch Replacement | PG&E | Dec-18 |
| 10 | Cooley Landing 115/60 kV Transformer Capacity Upgrade | PG&E | Apr-18 |
| 11 | Cortina No.3 60 kV Line Reconductoring Project | PG&E | Jun-18 |
| 12 | Diablo Canyon Voltage Support Project * | PG&E | On hold |
| 13 | East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV | PG&E | Apr-21 |

| | | | |
|---|---|---|---|
| | Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved) | | |
| 14 | Estrella Substation Project | PG&E/NEET West[129] | May-19 |
| 15 | Evergreen-Mabury Conversion to 115 kV | PG&E | Canceled |
| 16 | Fulton 230/115 kV Transformer | PG&E | Canceled |
| 17 | Fulton-Fitch Mountain 60 kV Line Reconductor | PG&E | Dec-19 |
| 18 | Glenn #1 60 kV Reconductoring | PG&E | Canceled |
| 19 | Glenn 230/60 kV Transformer No. 1 Replacement | PG&E | Jun-19 |
| 20 | Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade | PG&E | May-18 |
| 21 | Helm-Kerman 70 kV Line Reconductor | PG&E | Mar-18 |
| 22 | Ignacio – Alto 60 kV Line Voltage Conversion | PG&E | Dec-23 |
| 23 | Jefferson-Stanford #2 60 kV Line * | PG&E | On hold |
| 24 | Kern – Old River 70 kV Line Reconductor Project | PG&E | Completed |
| 25 | Kern PP 230 kV Area Reinforcement | PG&E | Dec-20 |
| 26 | Kearney-Caruthers 70 kV Line Reconductor | PG&E | Apr-19 |
| 27 | Kearney – Hearndon 230 kV Line Reconductoring | PG&E | Mar-19 |
| 28 | Lemoore 70 kV Disconnect Switches Replacement | PG&E | Jun-18 |
| 29 | Lodi-Eight Mile 230 kV Line | PG&E | Aug-18 |
| 30 | Los Banos-Livingston Jct-Canal 70 kV Switch Replacement | PG&E | Jun-18 |
| 31 | Los Esteros-Montague 115 kV Substation Equipment Upgrade | PG&E | Canceled |

[129] NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

| | | | |
|---|---|---|---|
| 32 | Maple Creek Reactive Support | PG&E | Dec-20 |
| 33 | McCall-Reedley #2 115 kV Line | PG&E | Canceled |
| 34 | Metcalf-Evergreen 115 kV Line Reconductoring | PG&E | May-19 |
| 35 | Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade | PG&E | Apr-22 |
| 36 | Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase | PG&E | Apr-20 |
| 37 | Midway-Temblor 115 kV Line Reconductor and Voltage Support | PG&E | Apr-22 |
| 38 | Missouri Flat – Gold Hill 115 kV Line | PG&E | May-18 |
| 39 | Monta Vista 230 kV Bus Upgrade | PG&E | Sep-20 |
| 40 | Moraga-Castro Valley 230 kV Line Capacity Increase Project | PG&E | Mar-21 |
| 41 | Morro Bay 230/115 kV Transformer Addition Project * | PG&E | On hold |
| 42 | Mosher Transmission Project | PG&E | Nov-19 |
| 43 | Napa – Tulucay No. 1 60 kV Line Upgrades | PG&E | Canceled |
| 44 | North East Kern Voltage Conversion Project | PG&E | Canceled |
| 45 | North Tower 115 kV Looping Project | PG&E | Dec-21 |
| 46 | NRS-Scott No. 1 115 kV Line Reconductor[130] | PG&E | Apr-19 |
| 47 | Oakhurst/Coarsegold UVLS | PG&E | Completed |
| 48 | Oro Loma – Mendota 115 kV Conversion Project | PG&E | Canceled |
| 49 | Oro Loma 70 kV Area Reinforcement | PG&E | May-20 |
| 50 | Pease 115/60 kV Transformer Addition and Bus Upgrade | PG&E | Dec-19 |
| 51 | Pittsburg 230/115 kV Transformer Capacity Increase | PG&E | May-22 |

[130] The scope of this project has been modified to include reconductoring of both NRS-Scott #1 & #2 115 kV lines. Cost responsibility between PG&E and SVP has not been resolved – ISO approval does not pre-suppose the outcome of the dispute process underway at FERC.

| | | | |
|---|---|---|---|
| 52 | Ravenswood – Cooley Landing 115 kV Line Reconductor | PG&E | Dec-20 |
| 53 | Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects) | PG&E | Dec-21 |
| 54 | Reedley 115/70 kV Transformer Capacity Increase | PG&E | Revised and Completed[131] |
| 55 | Reedley-Dinuba 70 kV Line Reconductor | PG&E | Canceled |
| 56 | Reedley-Orosi 70 kV Line Reconductor | PG&E | Canceled |
| 57 | Rio Oso – Atlantic 230 kV Line Project | PG&E | Canceled |
| 58 | Rio Oso 230/115 kV Transformer Upgrades | PG&E | Jun-22 |
| 59 | Rio Oso Area 230 kV Voltage Support | PG&E | Jun-22 |
| 60 | Ripon 115 kV Line | PG&E | Dec-18 |
| 61 | San Bernard – Tejon 70 kV Line Reconductor | PG&E | Apr-18 |
| 62 | San Mateo – Bair 60 kV Line Reconductor | PG&E | Canceled |
| 63 | Semitropic – Midway 115 kV Line Reconductor | PG&E | May-19 |
| 64 | Series Reactor on Warnerville-Wilson 230 kV Line | PG&E | Feb-18 |
| 65 | South of San Mateo Capacity Increase | PG&E | Jan-19 & Mar-26 |
| 66 | Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation) | PG&E | May-23 |
| 67 | Stagg – Hammer 60 kV Line | PG&E | Canceled |
| 68 | Stockton ‘A’ –Weber 60 kV Line Nos. 1 and 2 Reconductor | PG&E | Jun-19 |
| 69 | Table Mountain – Sycamore 115 kV Line | PG&E | Canceled |
| 70 | Vierra 115 kV Looping Project | PG&E | Apr-23 |
| 71 | Warnerville-Bellota 230 kV line reconductoring | PG&E | Jan-24 |

[131] Revised scope for the Reedley 115/70 kV Transformer Capacity Increase project excludes replacement of the Reedley 115/70 kV transformer. The associated terminal equipment work to increase the rating of the transformer is already completed. With this, the Reedley 115/70 kV Capacity Increase project is complete.

| | | | |
|---|---|---|---|
| 72 | Watsonville Voltage Conversion | PG&E | Canceled |
| 73 | West Point – Valley Springs 60 kV Line | PG&E | Oct-19 |
| 74 | Wheeler Ridge Voltage Support | PG&E | Dec-20 |
| 75 | Wheeler Ridge-Weedpatch 70 kV Line Reconductor | PG&E | Apr-19 |
| 76 | Wilson 115 kV Area Reinforcement | PG&E | Dec-23 |
| 77 | Wilson-Le Grand 115 kV line reconductoring | PG&E | Dec-20 |
| 78 | Panoche – Ora Loma 115 kV Line Reconductoring | PG&E | Dec-20 |
| 79 | Bellota 230 kV Substation Shunt Reactor | PG&E | Jan-19 |
| 80 | Cottonwood 115 kV Substation Shunt Reactor | PG&E | Nov-19 |
| 81 | Delevan 230 kV Substation Shunt Reactor | PG&E | Dec-19 |
| 82 | Ignacio 230 kV Reactor | PG&E | May-19 |
| 83 | Los Esteros 230 kV Substation Shunt Reactor | PG&E | Oct-19 |
| 84 | Wilson 115 kV SVC | PG&E | Dec-19 |
| 85 | 2nd Escondido-San Marcos 69 kV T/L | SDG&E | Dec-20 |
| 86 | 2nd Pomerado - Poway 69kV Circuit | SDG&E | Jun-18 |
| 87 | Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously-approved New Sycamore - Bernardo 69 kV line) | SDG&E | Feb-19 |
| 88 | Miguel 500 kV Voltage Support (aka Miguel VAR Support) | SDG&E | Completed |
| 89 | Miramar-Mesa Rim 69 kV System Reconfiguration | SDG&E | May -19 |
| 90 | Mission Bank #51 and #52 replacement | SDG&E | Jun-18 |
| 91 | Mission-Penasquitos 230 kV Circuit | SDG&E | Canceled |
| 92 | Reconductor TL663, Mission-Kearny | SDG&E | Nov-18 |

| | | | |
|---|---|---|---|
| 93 | Reconductor TL676, Mission-Mesa Heights | SDG&E | Dec-18 |
| 94 | Reconductor TL692: Japanese Mesa - Las Pulgas | SDG&E | Sep-19 |
| 95 | Rose Canyon-La Jolla 69 kV T/L | SDG&E | Jun-18 |
| 96 | Sweetwater Reliability Enhancement | SDG&E | Jun-20 |
| 97 | TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in) | SDG&E | Completed |
| 98 | TL632 Granite Loop-In and TL6914 Reconfiguration | SDG&E | Dec-20 |
| 99 | TL633 Bernardo-Rancho Carmel Reconductor | SDG&E | Feb-19 |
| 100 | TL644, South Bay-Sweetwater: Reconductor | SDG&E | Jun-20 |
| 101 | TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap) | SDG&E | Dec-19 |
| 102 | TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor | SDG&E | Jan-21 |
| 103 | TL695B Japanese Mesa-Talega Tap Reconductor | SDG&E | Dec-19 |
| 104 | TL 13820, Sycamore-Chicarita Reconductor | SDG&E | Canceled |
| 105 | TL13834 Trabuco-Capistrano 138 kV Line Upgrade | SDG&E | Dec-21 |
| 106 | Upgrade Los Coches 138/69 kV Bank 50 | SDG&E | Completed |
| 107 | 15 Mvar Capacitor at Basilone Substation | SDG&E | Completed |
| 108 | 30 Mvar Capacitor at Pendleton Substation | SDG&E | Completed |
| 109 | Reconductor TL 605 Silvergate – Urban | SDG&E | Jun-18 |
| 110 | Second Miguel – Bay Boulevard 230 kV Transmission Circuit | SDG&E | Jun-19 |
| 111 | TL600: “Mesa Heights Loop-in + Reconductor | SDG&E | Jun-18 |
| 112 | Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap | SCE | Completed |
| 113 | Kramer Reactors | SCE | Completed |

| | | | |
|---|---|---|---|
| 114 | Laguna Bell Corridor Upgrade | SCE | Dec-20 |
| 115 | Lugo Substation Install new 500 kV CBs for AA Banks | SCE | Dec-20 |
| 116 | Method of Service for Wildlife 230/66 kV Substation | SCE | Jun-23 |
| 117 | Path 42 and Devers – Mirage 230 kV Upgrades | SCE | Completed |
| 118 | Victor Loop-in | SCE | Completed |
| 119 | Eagle Mountain Shunt Reactors | SCE | Dec-18 |
| 120 | PDCI Upgrade (to 3220 MW) | SCE | TBD |
| 121 | Lugo – Victorville 500 kV Upgrade (SCE portion) | SCE | Dec-21 |
| 122 | Big Creek Rating Increase Project | SCE | Dec-18 |

Notes:

* The project requires further evaluation in future planning cycles to reassess the need scope of the project. All development activities are recommended to be put on hold until a review is completed.

Table 7.1-2: Status of Previously-Approved Projects Costing $50 M or More

| No | Project | PTO | Expected In-Service Date |
|---|---|---|---|
| 1 | Delaney-Colorado River 500 kV line | DCR Transmission | May-20 |
| 2 | Suncrest 300 Mvar dynamic reactive device | NEET West | May-17[132] |
| 3 | Atlantic-Placer 115 kV Line * | PG&E | On hold |
| 4 | Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project | PG&E | Dec-21 |
| 5 | Gates #2 500/230 kV Transformer Addition | PG&E | Dec-19 |
| 6 | Gates-Gregg 230 kV Line * | PG&E/MAT | On hold |
| 7 | Kern PP 115 kV Area Reinforcement | PG&E | Dec-23 |
| 8 | Lockeford-Lodi Area 230 kV Development | PG&E | Dec-22 |
| 9 | Martin 230 kV Bus Extension | PG&E | Oct-22 |
| 10 | Midway-Andrew 230 kV Project * | PG&E | On hold |
| 11 | Midway – Kern PP #2 230 kV Line | PG&E | Apr-20 |
| 12 | New Bridgeville – Garberville No. 2 115 kV Line | PG&E | On Hold |
| 13 | Northern Fresno 115 kV Area Reinforcement | PG&E | Mar-20 |
| 14 | South of Palermo 115 kV Reinforcement Project | PG&E | Dec-21 |
| 15 | Vaca – Davis Voltage Conversion Project | PG&E | Dec-23 |
| 16 | Wheeler Ridge Junction Substation | PG&E | May-24 |
| 17 | San Luis Rey Synchronous Condensers (i.e., two 225 Mvar synchronous condensers) | SDG&E | Completed |
| 18 | Artesian 230 kV Sub & loop-in TL23051 | SDG&E | Dec-20 |
| 19 | Imperial Valley Flow Controller (IV Phase Shifting Transformer) | SDG&E | Completed |

[132] In service date to be revisited by project sponsor when Environmental Impact Report is completed

| No | Project | PTO | Expected In-Service Date |
|---|---|---|---|
| 20 | 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 | Dec-21 |
| 21 | Sycamore-Penasquitos 230 kV Line | SDG&E | Jun-18 |
| 22 | South Orange County Dynamic Reactive Support – San Onofre (now 1-225 Mvar synchronous condenser)[133] | SDG&E | Apr-18 |
| 23 | South Orange County Dynamic Reactive Support - Santiago Synchronous Condenser - SCE's component (1-225 Mvar synchronous condenser)[134] | SCE | Jun-18 |
| 24 | Alberhill 500 kV Method of Service | SCE | Jun-21 |
| 25 | Harry Allen-Eldorado 500 kV transmission project | DesertLink LLC | May-20 |
| 26 | Lugo – Eldorado series cap and terminal equipment upgrade | SCE | Jun-20 |
| 27 | Lugo-Mohave series capacitor upgrade | SCE | Jun-19 |
| 28 | Mesa 500 kV Substation Loop-In | SCE | Jun-21 |

Notes:

* The project requires further evaluation in future planning cycles to reassess the need scope of the project. All development activities are recommended to be put on hold until a review is completed.

[133] The South Orange County Dynamic Reactive Support project was initially approved in the 2012-2013 Transmission Plan and initially awarded to SDG&E as it was expected to be located in the San Onofre area in SDG&E's service territory. In 2014, the project was split due to siting issues, replacing two synchronous condensers at a single site with instead locating one at the San Onofre substation and the second being awarded to SCE and located in the Santiago substation. This was reflected in system modeling and noted on Page 159 and in Table 3.2.6 in the 2014-2015 Transmission Plan, but Table 7.1-2 (line number 5) was inadvertently not updated to reflect the change.

[134] Refer to the preceding footnote.

## 7.2 Transmission Projects found to be needed in the 2017-2018 Planning Cycle

In the 2017-2018 transmission planning process, the ISO determined that 13 transmission projects were needed to mitigate identified reliability concerns, no policy-driven projects were needed to meet the 33 percent RPS. Four economic-driven projects were found to be needed. The summary of these transmission projects are in Table 7.2-1, Table 7.2-2, and Table 7.2-3.

A list of projects that came through the 2017 Request Window can be found in Appendix E.

Table 7.2-1: New Reliability Projects Found to be needed

| No. | Project Name | Service Area | Expected In-Service Date | Project Cost |
|---|---|---|---|---|
| 1 | Lakeville 60 kV Area Reinforcement | PG&E | Dec-21 | $7M |
| 2 | Vaca Dixon-Lakeville 230 kV Corridor Series Compensation | PG&E | Oct-19 | $11M |
| 3 | Newark-Lawrence 115 kV Line Limiting Facility Upgrade | PG&E | Dec-18 | $1.5M-$2M |
| 4 | Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade | PG&E | Jun-19 | $1.5M-$2M |
| 5 | Trimble-San Jose B 115 kV Line Limiting Facility Upgrade | PG&E | Dec-18 | $250K |
| 6 | Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate | PG&E | Feb-19 | $1M |
| 7 | Oakland Clean Energy Initiative | PG&E | TBD | $56-76 |
| 8 | Coburn-Oil Fields 60 kV system project | PG&E | May-22 | $7M-$10M |
| 9 | Herndon-Bullard 115 kV Reconductoring Project | PG&E | Jan-21 | $6M-$8M |
| 10 | Moorpark-Pardee 4th 230 kV circuit | SCE | Dec-20 | $45M |
| 11 | Suncrest 500/230 kV Transformer Rating Increase | SDG&E | Dec-18 | $1M |
| 12 | San Ysidro 69 kV Reconductoring | SDG&E | Dec-20 | $8M |
| 13 | Tie line Phasor Measurement Units | PG&E, SCE, VEA | Dec-20 | $11M |

Table 7.2-2: New Policy-driven Transmission Projects Found to be needed

| No. | Project Name | Service Area | Expected In-Service Date | Project Cost |
|---|---|---|---|---|
| | No policy-driven projects identified in the 2017-2018 Transmission Plan | | | |

Table 7.2-3: New Economic-driven Transmission Projects Found to be needed

| No. | Project Name | Service Area | Expected In-Service Date | Project Cost |
|---|---|---|---|---|
| 1 | San Jose-Trimble 115 kV line limitation and consideration of series reactors | PG&E | May-19 | $6M-$9M |
| 2 | Moss Landing–Panoche 230 kV Path Upgrade | PG&E | Dec-18 | $5M |
| 3 | IID S-Line Upgrade | SDG&E | Dec-21 | $50M |
| 4 | Bob-Mead 230 kV Reconductoring | VEA | Dec-20 | $25M |

## 7.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2017-2018 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

This section summarizes the reliance on preferred resources in the 2017-2018 Transmission Plan.

### 7.3.1 Additional achievable energy efficiency (AAEE) and Behind-the-Meter PV Generation

The ISO conducted sensitivity studies in the 2017-2018 transmission planning process reflecting both high load scenarios that did not rely on AAEE being achieved, and also "peak shift" scenarios considering later-day peak loads emerging as behind-the-meter solar PV generation impacts traditional mid-afternoon peak loads. These assessments are now becoming part of the routine analysis performed by the SIO, and the sensitivity analysis documented throughout chapter 2. In general, the results from the high load sensitivity studies without AAEE exhibited worsening of the reliability concerns identified in the base case; however, in some areas, additional reliability concerns were identified if the AAEE does not materialize as included in the base case assumptions. No mitigation solutions were recommended for these incremental reliability concerns as these were not identified in the analysis of the base case – thus the AAEE is being relied upon to materialize to maintain compliance with planning standards. The results of the sensitivity studies are included in chapter 2 within each of the local planning area sections as well as Appendix C.

Reliance on existing demand response programs are also documented throughout chapter 2.

### 7.3.2 Integrating Transmission Planning with Preferred Resource Procurement

In addition to relying on preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

*LA Basin-San Diego*

Considerable amounts of grid connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Tables 2.7-5 and 2.9-1, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be repurposed within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

*Oakland Sub-area*

As set out in section 2.5.5.4, the reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative".

*Moorpark and Santa Clara Sub-areas*

As set out in section 2.7.5.4, the ISO is recommending the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers as part of a multi-faceted solution to meeting local area needs that will include preferred resources being procured by Southern California Edison as part of SCE's procurement plan for the area submitted to the CPUC Energy Division on December 21, 2017. This plan will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling.

## 7.4 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional 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.

No regional transmission solutions recommended for approval in this 2017-2018 transmission plan are eligible for competitive solicitation.

## 7.5 Capital Program Impacts on Transmission High Voltage Access Charge

### 7.5.1 Background

The purpose of the ISO's internal High Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the 10 Year Transmission Plan on the access charge. The ISO is continuing to update and enhance its model since the tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in October 2013. Additional upgrades to the model have been made reflecting certain of the comments received from stakeholders.

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 tool 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.

The tool does not attempt to break out rate impacts by category, e.g. reliability-driven, policy-driven and economic-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 tariff 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 that was subsequently replaced by the broader policy-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 cost assumptions are appropriate on an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility.

### 7.5.2 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 are 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 are utilized, which necessitates some adjustments to rate base. These adjustments are “back-calculated” such that each PTO’s total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts.

The tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

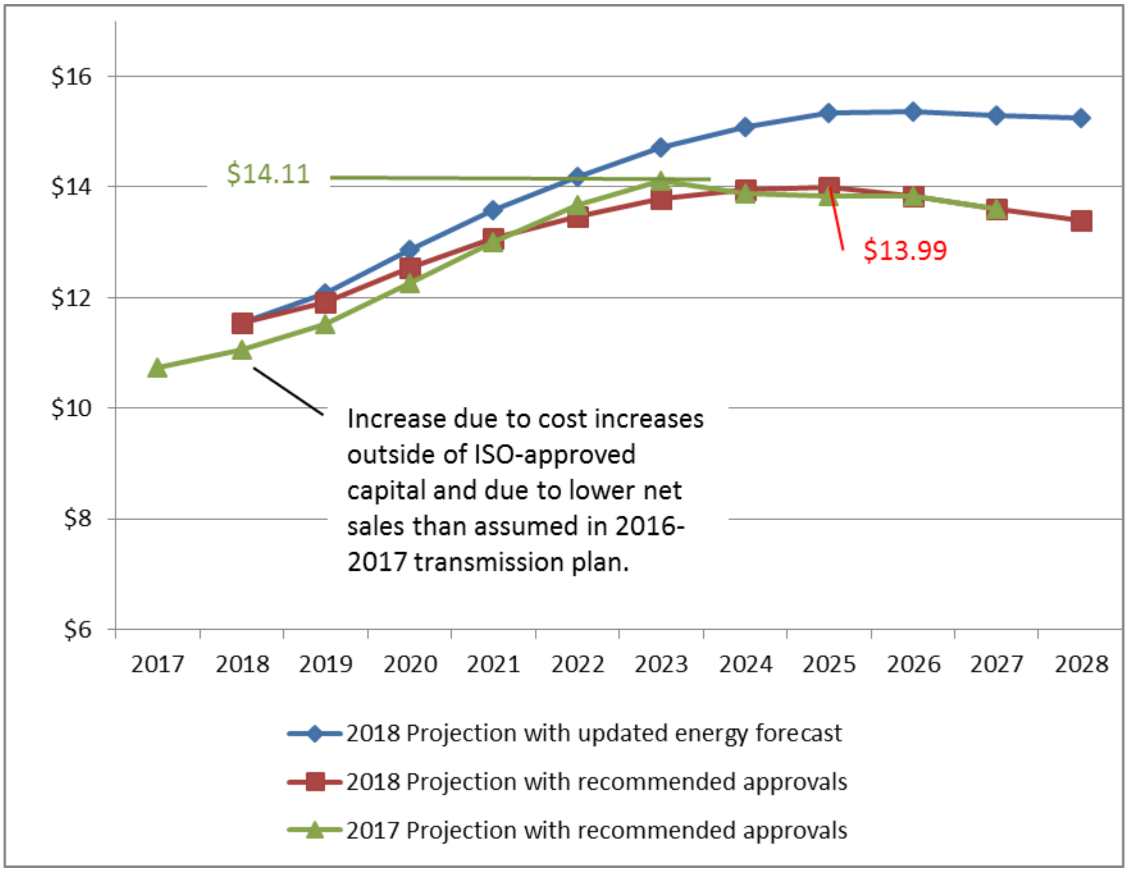
The ISO has also continued the trend commenced in earlier planning cycles in adjusting the long term forecast return on equity assumptions downward. While stakeholders have suggested that a 10% return may be appropriate, the ISO has considered this as a lower bound, and continued to base this year’s analysis of future transmission projects on a more conservative average of 11% in Figure 7.5-1. The overall return values for existing rate base assets are drawn from the PTO’s actual approved revenue requirements. An updated estimate from the 2016-2017 transmission planning process has been provided for comparison.

The estimate provided below reflects the latest updated costs for all previously approved projects and the revised scopes for projects with recommended scope changes. All projects recommended to be canceled have been removed from the estimate, and projects on hold are included in the estimate.

In cycles prior to the 2016-2017 Transmission Plan, adjustments had been made to maintain annual reliability-driven projects approvals above a certain threshold once it had been initially exceeded. However, consistent with the 2016-2017 Transmission Plan, only the cost of approved transmission projects and projects recommended to be approved have been included.

As in past planning cycles, a 1% load growth was assumed in overall energy forecast over which the high voltage transmission revenue requirement is recovered for comparison purposes. However, a sensitivity has also been included reflecting a forecast year over year decrease of 0.31% in energy served, consistent with the CEC's 2016 IEPR forecast[135] . This sensitivity is denoted as the"updated energy forecast" in Figure 7.5-1

Figure 7.5-1: Forecast of ISO High Voltage Transmission Access Charge Trended from First Year of Transmission Plan




In reviewing the latest estimate, several observations can be made. As noted in Figure 7.5-1, the 2018 TAC value for the 2018 projection is higher than the 2018 value from the 2017 projection due to cost increases outside of ISO-approved capital, and also due to lower net sales than assumed in the 2017 projection used in the 2016-2017 Transmission Plan. Further, the highest value reached in the 2018 projection is only slightly lower than the peak value in the 2017 projection despite the significant number of project cancelations and rescoping efforts reflected in this year's planning cycle. While those changes drove TAC increases downward, they were offset by new capital approvals and by higher cost estimates for other previously approved projects. Also, many of the canceled projects and revised projects reduced costs of facilties below 200 kV, which do not affect the regional high-voltage transmission access charge.

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[135] California Energy Demand Update Forecast 2015 - 2027, Mid Demand Baseline Case, Mid AAEE Savings http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN216264_20170227T144018_Corrected_LSE_and_BA_Tables_Mid_Baseline__Mid_AAEE.xlsx, Form 1.5a - Statewide, Line 56