APPENDIX G:
Production Cost simulation and Economic Assessment Detailed Results

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G. Production Cost Simulation and Economic Assessment Detailed Results

G.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 transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each cycle's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan.

G.2 Technical Study Approach and Process

G.2.1 ISO ratepayer benefit in TEAM methodology

Different components of ISO ratepayer 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 relied upon by the ISO includes three components of ISO ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues.

Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy 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 a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource. In addition to the production and capacity benefits, any other benefits under TEAM — where applicable and quantifiable — can also be included. All categories of benefits identified in the TEAM document[1] and how they are addressed in the economic study process are summarized and set out in detail in Table G.2-1.

Table G.2-1: Summary of TEAM Benefit Categories

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.	In addition to production cost benefits themselves, focusing on ISO net ratepayer benefits;	Benefits focused on ISO net ratepayer benefits through production cost modeling.
	2.5.2 Transmission loss saving benefit (AND IN CAPACITY BENEFITS FOR CAPACITY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	Energy-related savings are reflected in production cost modeling results.
Capacity benefits: Benefits resulting from increased importing capability into the ISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.	2.5.1 Resource adequacy benefit from incremental importing capability A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously: • The upgrade increases the import capability into the ISO's controlled grid in the study years. • There is capacity shortfall from RA perspective in ISO BAA in the study years and beyond. • The existing import capability has been fully utilized to meet RA requirement in the ISO BAA in the study years. • The capacity cost in the ISO BAA is greater than in other BAAs to which the new transmission connects.	These benefits are considered where applicable; note that local capacity reduction benefits are discussed below.
	2.5.2 Transmission loss saving benefit (AND IN PRODUCTION BENEFITS FOR ENERGY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	These benefits are considered, where applicable.
	2.5.3 Deliverability benefit Transmission upgrade can potentially increase generator deliverability to the region under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in Section 2.5.1 in TEAM (and in this table), such deliverability benefit can only be materialized when	This is primarily considered if the renewables portfolios identify the need for additional deliverability (as deliverability is used in TEAM and in ISO planning and generator interconnection studies) in which case the benefits may be policy benefits that

[1] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	have already been addressed in the development of portfolios, and further project development for this purpose for reducing local needs at this time is considered separately below.
	2.5.4 LCR benefit Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the ISO-controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.	LCR benefits are assessed, and valued according to prudent assumptions at this time given the state of the IRP resource planning at the time – and supported by the CPUC.
Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas, or by avoiding over-build.	2.5.5 Public-policy benefit If a transmission project increases the importing capability into the ISO-controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas. When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.	With the current coordination of resource portfolios with the CPUC and CEC in place, these issues are addressed in the course of the portfolio development process.
Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.	2.5.6 Renewable integration benefit As the renewable penetration increases, it becomes challenging to integrate renewable generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs. A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy. A transmission upgrade that creates a new tie or increases the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S	This can be considered as applicable, particularly for interregional transmission projects. Re-dispatch benefits would be included in the production cost savings in any event.

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	requirement may help relieving over-supply issue and curtailment of renewable resources. It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the ISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter. However, such a type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.	
Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.	2.5.7 Avoided cost of other projects If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project. Full assessment of the benefit from avoided costs is on a case-by-case basis.	This can be considered on a case by case basis, where applicable.

G.2.2 Production cost benefit n TEAM methodology

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.

Such an approach is consistent with the requirements of tariff Section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail below.

In the production benefit assessments, the ISO calculates ISO ratepayer's benefits[2] as follows:

- ISO ratepayers' production benefit = (ISO Net Payment of the pre-upgrade case) – (ISO Net Payment of the post-upgrade case)
- ISO Net Payment = (ISO load payment) – (ISO generator net revenue benefiting ratepayers) – (ISO transmission revenue benefiting ratepayers)

[2] WECC-wide societal benefits are also calculated to assess the overall reasonableness of the results and to assess the impact of the project being studied on the rest of the WECC-wide system, but not as the basis for determining whether the proejct is in the interests of the ISO ratepayer to proceed with. The WECC-wide societal benefits are assessed according to the following formula: *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*

The above calculation reflects the benefits to ISO ratepayers – offsetting other ISO ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to ISO ratepayers. These include:

- PTO owned transmission
- Generators owned by the utilities serving the ISO's load
- Wind and solar generation or other resources under contract with an ISO load-serving entity to meet the state renewable energy goal, and
- Other generators under contracts where information available for the public may be reviewed for consideration of the type and the length of contract.

How ISO ratepayer benefits relate to (and differ from) the ISO production cost benefits are shown in Figure G.2-1.

Figure G.2-1: Ratepayer Benefits vs. Production Cost Savings

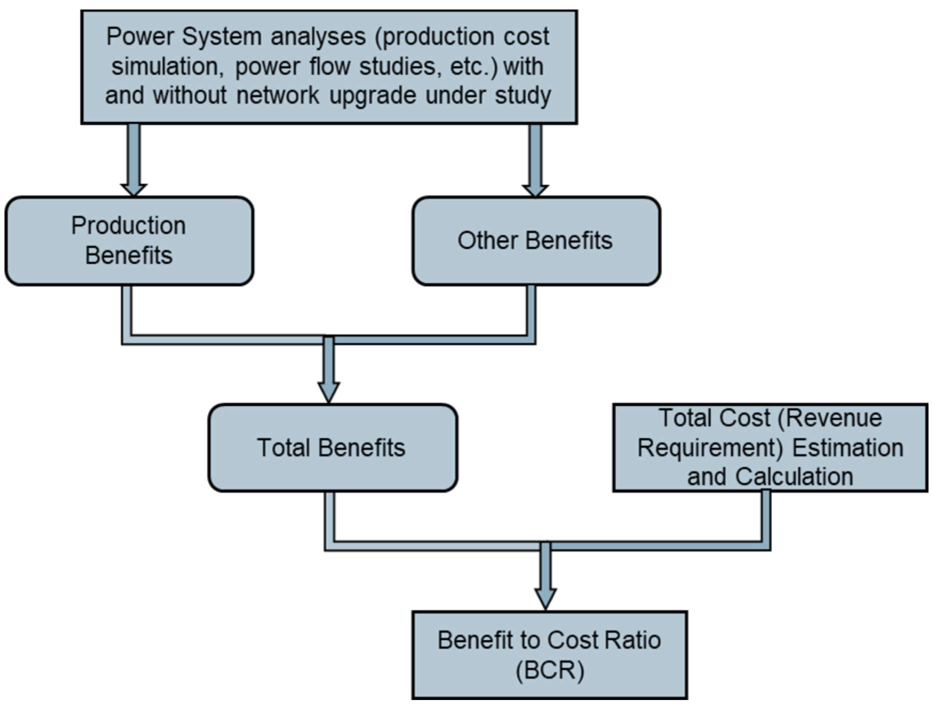
ISO Net Ratepayer Benefits from Production Cost Simulations are the sum of:	Types of Revenues and Costs calculated in Production Cost Studies	ISO "Production Cost" Savings are the sum of:
	Load Payments at Market Prices for Energy	
Yes	Reductions in ISO Ratepayer Gross Load Payments	
	Generation Revenues and Costs	
Yes	Increases in generator profits inside ISO for generators owned by or under contract with utilities or load serving entities, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
	Increases in merchant (benefits do not accrue to ratepayers) generator profits inside the ISO, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
Yes	Increases in profits of dynamic scheduled resources under contract with or owned by utilities or load serving entities, being the sum of:	
	Increases in these dynamic scheduled resource revenues	
	Decreases in these dynamic scheduled resource costs	
	Transmission-related Revenues	
Yes	Increases in transmission revenues that accrue to ISO ratepayers	
	Increases in transmission revenue for merchant (e.g. non-utility owned but under ISO operational control) transmission	

G.2.3 Technical study process

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement of the project under study, as described in the TEAM. To justify a proposed transmission solution, the ISO ratepayer benefit must be considered relative to the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. 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 transmission solution.

The technical approach of the economic planning study is depicted in Figure G.2-2. 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 G.2-2: Technical approach of economic planning study



G.2.4 Congestion revenue allocation in production cost benefit calculation

In the current TEAM methodology, congestion revenue is allocated based on transmission ownership as discussed in section G.2.2. This congestion revenue allocation approach has been used in CAISO's transmission economic assessment since the TEAM methodology was adopted by CAISO in 2005. The market operation evolved in many ways in the past two decades and power market footprints experienced significant expansion in the Western Interconnection. The resulting changing flow patterns triggered the consideration of potential revisions to the congestion revenue allocation approach in the stakeholder meeting on November 19, 2025. The proposed potential changes were:

- Congestion revenue is allocated to areas that have net positive flow contribution to constraints
- Allocation is based on net generation distribution factors of area to constraint
- This approach can be applied to congestion within the ISO or the entire WECC system

With the revised flow contribution-based approach, congestion revenue on ISO internal constraints is only partially allocated to ISO's ratepayers, even though ISO's PTOs may have 100% ownership on the transmission lines.

In this planning cycle, production cost benefit calculations were performed on the current ownership-based congestion revenue allocation approach and the revised approach. The ISO considered these results on a case by case basis to understand the implications on the viability of economic-driven projects.

G.3 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 potential transmission solutions. In these studies, all costs and benefits are expressed in 2024 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

G.3.1 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 transmission solution, when necessary, the financial parameters listed in Table G.3-1 are used. The net present value of the costs (and benefits) is calculated using a social discount rate of 7% (real) with sensitivities at 5% as needed.

Table G.3-1: 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	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 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 assessment is 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio set out in the ISO's TEAM documentation[3] that was based on prior experiences of the utilities in the ISO. The update reflects changes in federal income-tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced on a case-by-case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be compared to the annual benefits identified for those projects. This has the effect of the same comparative outcome, but adapts to both the shorter lifespans of battery storage and

[3] The ISO expects to update the TEAM documentation dated November 2, 2017 to reflect this change.

the varying lifespans of different major equipment within a battery storage facility that impact the levelized cost of the facility.

G.3.2 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 transmission solution. 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.[4]

In general, when detailed analysis of a high priority study area is required, production-cost simulation and subsequent benefits calculations are conducted for the 10th planning year. For years beyond the 10th planning year the benefits are estimated by extending the 10th year benefit with an assumed escalation rate. In this planning cycle, however, as indicated in section 4.5, the 10th year and the 15th year- in this case, the 2035-year and the 2040-year, load forecast and resource assumption were used in the planning PCM cases. Accordingly, the 15th year case, i.e. the 2040-year case was used as the main case for economic assessment.

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 2040 = 0% (real), and
- Benefits discount rate = 7% (real) with sensitivities at 5% as needed.

G.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined, a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, 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. As discussed in the

[4] Discount of yearly benefit into the present worth is calculated by $b_i = B_i / (1 + d)^i$, where b_i and B_i are the present and future worth respectively; d is the discount rate; and i is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7%. 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.

previous section, the traditional ISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects can be assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the ISO must also assess any other risks, impacts, or issues.

G.3.4 Valuing Local Capacity Requirement Reductions

As noted in Chapter 1 and earlier in this Appendix, the ISO recognizes that additional coordination on the long-term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. This is particularly important in considering how to assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas where, based on current planning assumptions, the gas-fired generation is sufficient to meet local capacity needs. If there are sufficient gas-fired generation resources to meet local capacity needs over the planning horizon, there is not a need for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, it cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources. While future IRP efforts are expected to provide more guidance and direction regarding expectations for the gas-fired generation fleet at a policy level, without that broader system perspective available at this time, the ISO has taken a conservative approach in assessing the value of a local capacity reduction benefit when considering a transmission reinforcement or other alternatives that could reduce the need for existing gas-fired generation providing local capacity.

In this planning cycle, the capacity costs in the 2023 CPUC Resource Adequacy Report[5], which is the most recently available report at the time, were used in assessing local capacity reduction benefit.

G.4 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

[5] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf

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:

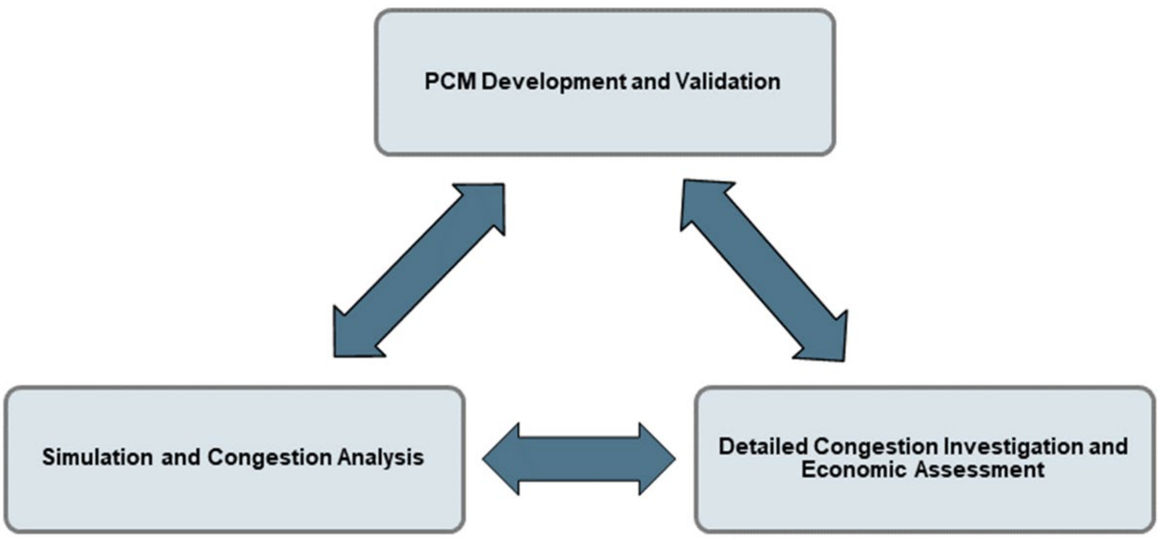
1. Network model (transmission topology, generator location, and load distribution).
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, energy storage model, renewable profiles, and renewable curtailment and price model.
4. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers.
5. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission cost and assignment, fuel price and assignment, 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 lines 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 purposes, 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 transmission solution 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 transmission solution provides sufficient economic benefits 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 G.4-1 shows these components and their interaction.

Figure G.4-1: Steps of production cost simulation in Economic planning



G.5 Production cost simulation tools

The ISO primarily used the software tools listed in Table G.5-1 for this economic planning study.

Table G.5-1: Economic Planning Study Tools

Program name	Version	Functionality
Hitachi GridView™	10.4.8	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 (8784 hours for leap year)

G.6 ISO Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) 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 final.

G.6.1 Starting database

The 2025-2026 transmission planning process PCM development started from the ADS 2034 PCM. Using this databases, the ISO developed the base cases for the ISO 2025-2026 transmission planning process production cost simulation. These base cases included modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section, and validated incremental changes in the ADS PCM.

It is worth noting that the ADS PCM is an evolving product, so the ISO's planning PCM only incorporated ADS PCM changes that were approved and validated before a cut-off date. In this planning cycle, the changes in the ADS 2034 PCM after November 12, 2025 were not included in the ISO's planning PCM.

G.6.2 Study years

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 an optional 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.

In this planning cycle, the CPUC provided the 2035 and 2040 IRP portfolios to the ISO for transmission planning study. The 2035 base portfolio and sensitivity portfolio PCM cases and the 2040 base portfolio PCM cases were developed for congestion analysis. The 2040 base portfolio PCM case was used for detailed economic assessment.

G.6.3 Generation resources

Generator locations and installed capacities in the 2035 and 2040 PCM cases are consistent with the reliability and policy assessment power flow cases for 2035 and for 2040, respectively, including both conventional and renewable generators. Chapter 3 and Appendix F provides more details about the renewables portfolios.

The CPUC IRP base and sensitivity portfolios included out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC IRP portfolios expected to require new transmission, while some rely on existing transmission, to deliver their wind energy to the ISO load. For the out-of-state wind resources that require new transmission, the CPUC IRP portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

In the planning PCM in this planning cycle, New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona, which is consistent with the last planning cycle. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus.

The CPUC IRP portfolios included out-of-state wind in Wyoming areas and in Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, the Wyoming wind was modeled associated with the TransWest Express project, and the Idaho wind was modeled associated with the SWIP North project, as baseline assumption.

G.6.4 Transmission Network

The ADS PCM uses a nodal model to represent the entire WECC transmission network. However, the network model in the ADS PCM is based on a power flow case that is different from the ISO's reliability and policy power flow cases developed in the current planning cycle. The ISO took a more comprehensive approach and modified the network model for the ISO system to exactly match the policy 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 policy 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 policy assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

G.6.5 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 ADS PCM 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 ADS PCM 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 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, 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 ISO transmission grid at lower voltage than 230 kV are enforced.

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.

G.6.6 Load

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 conditions across the ISO system. The CEC California Energy Demand Updated Forecast for 2035 and 2040, consistent with the demand forecast in the reliability assessment as described in Chapter 2, were used to develop the planning PCM cases. Load modifiers, including DR, BTM PV, AAEE, AATE, AAFS, and Data Center load were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

G.6.7 Fuel price and CO2 price

The forecast of Natural Gas prices, Coal prices, and CO2 prices were the same as in the ADS 2034 PCM. All prices are in 2024 real dollars.

G.6.8 Renewable curtailment price model

The PCM in this planning cycle continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh, as shown in Table G.6-1

Table G.6-1: Multi-blocks renewable model

Block	Price ($/MWh)
1	-23
2	-24
3	-25
4	-26
5	-27

G.6.9 Battery cost model and depth of discharge

The ISO also refined its modeling of battery storage through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the cycle life (i.e. the number of cycles) and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost. Cycle life represents available cycles until remaining energy is equivalent to average DoD, as further clarified in the updated DOE report for the storage cost forecast prepared by PNNL in 2022[6]. Based on this clarification of the cycle file definition, the battery's operation cost is calculated using the following equation:

$$Average\ Cost = (1 - DoD) * \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

The baseline assumptions for battery parameters in this planning cycle were also based on the 2030 forecast in the same DOE/PNNL report:

- DoD: 80%
- Cycle life: 2640 cycles

[6] https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

- Per unit replacement cost: $109,450/MWh

With the above parameters, the average cost was $5.18/MWh.

G.6.10 Co-located and hybrid resource model

Starting with this planning cycle, co-located and hybrid resource were modeled in the planning PCM. A co-located or hybrid resource normally includes battery components and solar components and can also be combination of battery and other types of resources such as wind or thermal generators. Except for where a hybrid resource has a single market ID and a co-located resource may have multiple market IDs, there are a lot of similarities between the hybrid and co-located resources from operation and modeling perspectives, although there may be differences in financial and operational requirements. As the policy and operation requirements for co-located and hybrid resources are still under development, the planning PCM in this planning cycle used the same approach to model co-located and hybrid resources.

To model co-located and hybrid resources in PCM, two constraints that are similar to the P_{max} and P_{min} constraints of any other generators can be added:

- P_{max} constraint

$$P_{solar} + P_{battery} + REGUP_{battery} + LFUP_{solar} + LFUP_{battery} + SPIN_{battery} + FR_{battery} \leq Pmax \quad (1)$$

- P_{min} constraint (charging constraint)

$$P_{solar} + P_{battery} - REGDOWN_{battery} - LFDOWN_{solar} - LFDOWN_{battery} \geq Pmin \quad (2)$$

The $Pmax$ is normally the allowed maximum output at the point of interconnection of the generator. The $Pmin$ can be negative if the co-located or hybrid resource can charge from the grid, or equal to zero if the battery component is not expected to charge from the grid. $P_{battery}$ is positive when the battery is discharging, and negative when the battery is charging. Ancillary services and operating reserves are considered in the P_{max} and P_{min} constraints, including regulation up and down (REGUP and REGDOWN), load following up and down (LFUP and LFDOWN), spinning reserve (SPIN), and frequency response (FR).

It is noted that the P_{min} constraint was not used in this planning cycle, because there is a lack of clarity of charging requirement for co-located and hybrid resources. It will be considered in future planning cycles when there is additional clarity for the charging requirement.

G.6.11 Dynamic line rating

Dynamic Line Rating (DLR) refers to transmission line rating varying based on local conditions, such as ambient air temperature, wind speed, cloud cover, solar heating, and precipitation, etc., rather than a static rating assumption. DLR can provide additional capacity for a transmission line. FERC order 1920[7] requires transmission providers to consider more fully the alternative transmission technologies of dynamic line ratings in long-term transmission planning.

In CAISO's production cost simulation, many congestions were observed happening in the evening time or in the months when temperature is not high. Such congestion can be potentially mitigated or reduced by adopting dynamic line ratings for the lines.

In this planning cycle, dynamic line ratings were not modeled in PCM cases, since it not only requires operational history data of weather conditions and line ratings, but also requires software and modeling enhancements to accommodate the data in PCM. CAISO will coordinate with CAISO's PTOs, WECC, and the software vendor of GridView, to explore the feasibility and possibility of implementing dynamic line rating in PCM model in future planning cycles.

G.7 Production Cost Simulation Results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of the ISO transmission network was performed to identify which facilities in the ISO-controlled grid were congested. Renewable curtailment and generation utilization were also summarized based on the production cost simulation results.

G.7.1 2035 Base Portfolio PCM Congestion Results

The results of the congestion assessment in the 2035 base portfolio PCM are listed in Table G.7-1. Columns "Cost Forward" and "Duration Forward" are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns "Cost Backward" and "Duration Backward" are the cost and duration of congestion, respectively, when flow is in backward direction.

Table G.7-1: Congestion in the ISO-controlled grid in the 2035 base portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	922,923	3,177	922,923	3,177
2	Path 15 Corridor	MANNING-MN_GT_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	483,219	2,929	483,219	2,929

[7] https://www.ferc.gov/media/e1-rm21-17-000

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
3	Path 26 Corridor	P26 Northern-Southern California	393	11	264,817	2,440	265,210	2,451
4	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	164,073	4,737	164,073	4,737
5	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	90,893	630	90,893	630
6	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	76,043	780	76,043	780
7	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	58,468	642	58,468	642
8	Path 15 Corridor	GATES-GT_MW_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	54,422	570	54,422	570
9	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	51,555	586	51,555	586
10	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	48,295	725	250	42	48,545	767
11	East of Pisgah-GLW/VEA	GAMEBIRD-PAHRUMP 138 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	0	0	32,712	3,457	32,712	3,457
12	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	32,091	1,932	0	0	32,091	1,932
13	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	32,049	283	32,049	283
14	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	29,124	562	29,124	562
15	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	26,747	64	26,747	64
16	SDG&E/CFE	P45 SDG&E-CFE	4,869	890	14,964	597	19,832	1,487
17	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	14,143	204	14,143	204
18	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	13,858	79	13,858	79
19	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	13,013	187	13,013	187
20	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	10,761	174	10,761	174
21	COI Corridor	P66 COI	4,352	97	5,573	45	9,925	142
22	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	7,921	95	7,921	95
23	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	6,406	322	6,406	322
24	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	5,952	68	5,952	68
25	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	5,722	250	0	0	5,722	250
26	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	5,488	575	5,488	575
27	PG&E Kern 230 kV	GATES D-CALFLATSSS 230 kV line #1	0	0	4,884	810	4,884	810
28	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	4,437	473	4,437	473
29	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-1 Tesla-Tracy 500kV #1	3,665	163	0	0	3,665	163
30	SCE Lugo - Rancho Vista 500 kV	LUGO-RANCHVST 500 kV line, subject to SCE N-2 Lugo-Mira Loma 500 kV	3,663	214	0	0	3,663	214
31	TWE	TWE-IPP-TWE-SC1A 500 kV line #1	0	0	3,592	40	3,592	40
32	PG&E Fresno 115 kV	LPRNJCTSS-GWFHANFORDSS 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	3,461	511	0	0	3,461	511
33	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	3,199	806	0	0	3,199	806
34	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	3,161	1,133	0	0	3,161	1,133

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
35	SCE Northern	PARDEE-VINCENT 230 kV line, subject to SCE N-2 Vincent2-SClara #1 and Antelope-Pardee #1 230 kV	0	0	2,574	287	2,574	287
36	PG&E GBA	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	2,515	101	2,515	101
37	PG&E Fresno 115 kV	MANCHSTR-HERNDON 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	1,916	37	1,916	37
38	TWE	TWE-SC1B-TWE-CRYS 500 kV line #1	0	0	1,903	26	1,903	26
39	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-OtayMesa-Miguel and BayBlvd-OtayMesa-Miguel 230kV	0	0	1,711	149	1,711	149
40	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	1,438	90	1,438	90
41	SCE North of Lugo	INYO 115/115 kV transformer #1	696	4,064	720	4,129	1,416	8,193
42	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	1,401	103	0	0	1,401	103
43	Path 41 Sylmar transformer	P41 Sylmar to SCE	1,313	139	0	0	1,313	139
44	SCE Metro	BARRE-LEWIS 230 kV line #1	0	0	1,287	263	1,287	263
45	Path 46 WOR	P46 West of Colorado River (WOR)	1,189	37	0	0	1,189	37
46	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	1,146	29	1,146	29
47	TWE	INTERMT-TWE-IPP 345 kV line #1	0	0	1,104	15	1,104	15
48	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	1	1,088	111	1,088	112
49	SCE Eastern	J.HINDS-MIRAGE 230 kV line #1	887	205	0	0	887	205
50	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	875	21	0	0	875	21
51	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	833	71	0	0	833	71
52	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	601	18	601	18
53	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	0	0	489	80	489	80
54	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	431	15	0	0	431	15
55	PG&E GBA	SANJOSEB230 230/115 kV transformer #1	404	142	0	0	404	142
56	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-2 Tesla-Tracy 500kV #1 and Tracy-LosBanos 500kV #1	384	26	0	0	384	26
57	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	366	22	366	22
58	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	359	29	0	0	359	29
59	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	298	38	0	0	298	38
60	PG&E GBA	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	296	82	0	0	296	82
61	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line #1	280	26	0	0	280	26
62	East of Pisgah	P61 Lugo-Victorville 500 kV Line	0	0	243	99	243	99
63	SCE Metro	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	0	0	240	31	240	31
64	East of Pisgah-GLW/VEA	VEA_PST_2-IS TAP 138 kV line #1	230	60	0	0	230	60
65	SDG&E Bulk	IMPRLVLY WST 230/500 kV transformer #3	202	203	0	0	202	203
66	TWE	INTERMT-TWE-IPP 345 kV line #2	0	0	200	7	200	7
67	COI Corridor	FR_TM_22-FERNROADSS 500 kV line #2	145	13	0	0	145	13

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
68	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	0	1	141	35	141	36
69	Path 25 PACW-PG&E 115 kV	CASCADE-DELTAP 115 kV line #1	0	0	133	10	133	10
70	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	124	99	124	99
71	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	120	21	120	21
72	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	110	99	110	99
73	SCE Eastern	DVRS_RB_11-DVRS_RB_12 500 kV line #1	0	0	87	3	87	3
74	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	83	8	83	8
75	SDG&E Bulk	IMPRLVLY 500/500 kV transformer #3	0	0	80	76	80	76
76	SCE Eastern	JHINDMWD-EAGLEMTN 230 kV line #1	65	9	0	0	65	9
77	SCE Northern	VINCNT2-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	64	16	0	0	64	16
78	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	62	7	0	0	62	7
79	SCE Vincent - MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	56	25	56	25
80	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	0	0	54	15	54	15
81	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	42	29	0	0	42	29
82	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	40	13	0	0	40	13
83	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	35	2	0	0	35	2
84	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	34	4	34	4
85	PG&E Kern 230 kV	GATES F-Q1593SWSTA 230 kV line #1	0	0	31	160	31	160
86	PG&E Sierra	P24 PG&E-Sierra	27	8	0	0	27	8
87	PG&E North Valley 230 kV	LAKEVILE-T22_93 230 kV line #1	0	0	26	2	26	2
88	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	25	5	0	0	25	5
89	PG&E GBA	MORAGA-CASTROVL 230 kV line #1	24	5	0	0	24	5
90	SCE Eastern	DEVERS-devers1i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	23	68	0	0	23	68
91	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	23	21	23	21
92	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line #3	0	0	22	9	22	9
93	SDG&E Northern 69 kV	PENDLETN-SANLUSRY 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	19	475	19	475
94	PG&E North Valley 230 kV	T22_93-FULTON 230 kV line #1	0	0	19	4	19	4
95	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	19	22	19	22
96	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	17	1	17	1
97	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	16	16	16	16
98	PG&E Kern 230 kV	Q1593SWSTA-MIDWAY-F 230 kV line #1	0	0	16	246	16	246
99	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line #1	0	0	15	29	15	29

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
100	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	15	155	0	0	15	155
101	PG&E GBA	NRS-TRIMBLE 230 kV line #1	0	0	14	7	14	7
102	PG&E GBA	C.COSTAPPE-WINDMASTERJT 230 kV line #1	13	1	0	0	13	1
103	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	10	1	10	1
104	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	9	46	9	46
105	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line #2	0	0	8	1	8	1
106	SCE North of Lugo	TAP710-INYOKERN 115 kV line #1	8	5	0	0	8	5
107	COI Corridor	RM_FR_11-FERNROADSS 500 kV line #1	5	2	0	0	5	2
108	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	4	2	4	2
109	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	4	2	0	0	4	2
110	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	4	6	0	0	4	6
111	PG&E GBA	WINDMASTERJT-DELTAPMP 230 kV line #1	3	3	0	0	3	3
112	SCE Blythe 161 kV	BLYTHE-BLYTHESC 161 kV line #1	2	1	0	0	2	1
113	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	2	6	0	0	2	6
114	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line #3	0	0	2	1	2	1
115	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-2 LoganCR-Delevn and Delevn-Cortina 230 kV with SPS	2	18	0	0	2	18
116	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	2	2	0	0	2	2
117	PG&E MorroBay 230 kV	MORROBAY-DIABLOCN 230 kV line #1	0	0	1	6	1	6
118	East of Pisgah	BAKER-MTN PASS 115 kV line #1	0	0	1	3	1	3
119	SDG&E Bulk	HASSYAMP-N.GILA 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500kV	1	1	0	0	1	1
120	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-1 Delevn-Cortina 230 kV with SPS	1	9	0	0	1	9

In Table G.7-1, the second column shows the branch group or local area where the congestion is located. The aggregated congestion across specific branch groups and local areas in 2035 was summarized in Table G.7-2, ranked based on the aggregated congestion cost.

Table G.7-2: Aggregated congestion in the 2035 base portfolio PCM

No.	Aggregated congestion	Aggregated Congestion Cost ($M)	Aggregated Congestion Hours
1	Path 15 Corridor	1,779.96	9,899
2	Path 26 Corridor	392.81	4,677
3	Path 65 PDCI	164.07	4,737
4	SCE North of Lugo	36.71	10,936
5	SCE Metro	33.58	577
6	East of Pisgah-GLW/VEA	32.94	3,517
7	SDG&E/CFE	22.83	1,799
8	SCE Northern	14.98	1,052
9	COI Corridor	10.08	157
10	SWIP North	7.92	95
11	TWE	6.80	88
12	SCE Eastern	6.58	808
13	PG&E Fresno 115 kV	5.41	552
14	PG&E Kern 230 kV	4.93	1,216
15	PG&E GBA	4.81	453
16	PG&E Tesla 230 kV	4.05	189
17	SCE Lugo - Rancho Vista 500 kV	3.66	214
18	SCE Antelope 66kV	3.16	1,133
19	PG&E POE - RIO OSO 230 kV	1.40	103
20	Path 41 Sylmar transformer	1.31	139
21	SDG&E 230 kV	1.26	174
22	Path 46 WOR	1.19	37
23	SDG&E Bulk	0.58	318
24	PG&E Sierra	0.52	88
25	Path 25 PACW-PG&E 115 kV	0.49	39
26	East of Pisgah	0.28	112
27	PG&E North Valley 230 kV	0.21	67
28	SCE Vincent - MiraLoma 500kV	0.06	25
29	SDG&E Northern 69 kV	0.03	630
30	PG&E Collinsville corridor	0.03	45
31	Moenkope - Eldorado 500 kV	0.02	5
32	PG&E Fresno 230 kV	0.00	2
33	SCE Blythe 161 kV	0.00	1
34	PG&E MorroBay 230 kV	0.00	6

G.7.2 2035 Base Portfolio PCM Curtailment Results

Table G.7-3 shows the wind and solar generation curtailment in the ISO system in the base portfolio PCM. In this table, the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were not obvious transmission constraints nearby. Renewable curtailment in this planning cycle's PCM results was mainly observed in the areas where transmission congestion occurred. The overall renewable curtailment remained at similar level as in the previous planning cycle.

Table G.7-3: Wind and solar curtailment summary in the 2035 base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	33,596	1,021	34,616	2.95%
NM	27,853	239	28,093	0.85%
SCE Eastern	25,171	172	25,343	0.68%
PG&E Fresno	20,773	843	21,616	3.90%
SDGE East of Miguel	14,834	28	14,861	0.19%
OSW-Diablo Canyon	12,819	1,315	14,134	9.30%
SCE EOP, GLW/VEA	13,899	68	13,967	0.49%
PG&E Kern	13,108	494	13,602	3.63%
WY	11,530	86	11,615	0.74%
SCE NOL	9,398	276	9,675	2.86%
OSW-Humboldt	8,203	0	8,203	0.00%
PG&E Greater Bay Area	6,674	0	6,674	0.00%
NW	4,194	0	4,194	0.00%
AZ	3,078	44	3,122	1.41%
ID	3,043	7	3,050	0.23%
PG&E Central Valley	2,385	0	2,385	0.00%
PG&E N. Valley	1,884	0	1,884	0.00%
IID	1,719	16	1,735	0.91%
NV	667	24	692	3.52%
BANC	408	0	408	0.00%
PG&E N. Coast	379	0	379	0.00%
San Diego	279	0	279	0.00%
SCE Metro	265	0	265	0.10%
PG&E North Bay	67	0	67	0.00%
Total	**216,228**	**4,634**	**220,862**	**2.10%**

G.7.3 2035 Base Portfolio PCM Gas-fired Generator Utilization

The average capacity factors of gas-fired generators by area in the 2035 base portfolio PCM were summarized in Table G.7-4. The capacity factors increased in this planning cycle due to the increase in data center load and battery. The removal of the Del Amo project also contributed to the gas-fired generator capacity factor increase in the southern California areas.

Table G.7-4: Gas-fired generator utilization in the 2035 base portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,259	5,193,219	0.23
PG&E Central Valley	840	1,474,943	0.16
PG&E Fresno	1,230	1,959,366	0.18
PG&E Greater Bay Area	5,680	19,876,578	0.33
PG&E Humboldt	163	186,834	0.13
PG&E Kern	2,972	9,672,012	0.22
PG&E North Valley	1,491	3,723,061	0.24
SCE Blythe	263	1,525,851	0.66
SCE Eastern LA Basin	2,620	4,701,389	0.27
SCE Eldorado	525	1,255,652	0.27
SCE North of Lugo	980	2,574,679	0.33
SCE North of Magunden	56	43,367	0.30
SCE South of Magunden	1,119	2,376,243	0.24
SCE Tehachapi	4	3,372	0.10
SCE Ventura	259	340,055	0.14
SCE Western LA Basin	4,060	9,631,606	0.20
SDG&E Bulk	1,004	2,076,682	0.23
SDG&E San Diego	2,712	3,806,436	0.16
System Total	**27,237**	**70,421,346**	**0.30**

G.7.4 2040 Base Portfolio PCM Congestion Results

The results of the congestion assessment in the 2040 base portfolio PCM were listed in Table G.7-5. Columns "Cost Forward" and "Duration Forward" are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns "Cost Backward" and "Duration Backward" are the cost and duration of congestion, respectively, when flow is in backward direction.

Table G.7-5: Congestion in the ISO-controlled grid in the 2040 base portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	885,359	3,866	885,359	3,866
2	Path 15 Corridor	MANNING-MN_GT_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	536,317	2,921	536,317	2,921
3	Path 26 Corridor	P26 Northern-Southern California	24	11	218,866	2,382	218,890	2,393
4	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	153,204	4,300	153,204	4,300
5	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	132,298	2,785	132,298	2,785

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
6	East of Pisgah-GLW/VEA	GAMEBIRD-PAHRUMP 138 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	0	0	117,924	6,443	117,924	6,443
7	Path 15 Corridor	GATES-GT_MW_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	107,896	679	107,896	679
8	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	102,522	991	102,522	991
9	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	93,224	545	93,224	545
10	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	79,016	1,124	104	24	79,120	1,148
11	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	74,577	809	0	0	74,577	809
12	SCE Lugo - Rancho Vista 500 kV	LUGO-RANCHVST 500 kV line, subject to SCE N-2 Lugo-Mira Loma 500 kV	64,757	996	0	0	64,757	996
13	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	59,820	287	59,820	287
14	SCE Northern	PARDEE-VINCENT 230 kV line, subject to SCE N-2 Vincent2-SClara #1 and Antelope-Pardee #1 230 kV	0	0	49,354	1,792	49,354	1,792
15	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	47,097	5,434	0	0	47,097	5,434
16	PG&E GBA	NRS 230/115 kV transformer #1	45,904	288	0	0	45,904	288
17	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	43,520	406	43,520	406
18	PG&E Moss Landing - Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line #1	0	0	39,457	1,219	39,457	1,219
19	PG&E Fresno 230 kV	KEARNEY-HERNDON 230 kV line #1	36,590	2,185	0	0	36,590	2,185
20	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	31,186	493	31,186	493
21	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	30,444	358	30,444	358
22	PG&E Moss Landing - Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Manning-Metcalf 500 kV with SPS	0	0	28,522	558	28,522	558
23	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-1 Tesla-Tracy 500kV #1	24,113	888	0	0	24,113	888
24	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	21,129	448	21,129	448
25	PG&E GBA	NRS 230/115 kV transformer #2	17,256	45	0	0	17,256	45
26	PG&E GBA	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	16,740	441	16,740	441
27	SDG&E/CFE	P45 SDG&E-CFE	4,545	889	10,414	537	14,959	1,426
28	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	14,528	1,612	0	0	14,528	1,612
29	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	14,144	303	14,144	303
30	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	12,857	204	12,857	204
31	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	11,705	56	11,705	56
32	SCE Metro	BARRE-LEWIS 230 kV line #1	0	0	11,058	938	11,058	938
33	PG&E North Valley 230 kV	BRNY_FST_JCT-PIT 1 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	10,708	614	10,708	614
34	PG&E Fresno 115 kV	MANCHSTR-HERNDON 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	10,562	241	10,562	241
35	PG&E GBA	SANJOSEB230 230/115 kV transformer #1	10,308	1,279	0	0	10,308	1,279

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
36	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	8,960	168	8,960	168
37	Path15 Corridor	FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV with SPS	8,717	354	0	0	8,717	354
38	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	8,310	1,051	8,310	1,051
39	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	7,935	727	7,935	727
40	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	7,863	614	7,863	614
41	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	7,851	511	0	0	7,851	511
42	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	6,846	219	0	0	6,846	219
43	PG&E GBA	NRS-TRIMBLE 230 kV line #1	0	0	6,500	1,988	6,500	1,988
44	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	5,883	650	5,883	650
45	TWE	TWE-SC1B-TWE-CRYS 500 kV line #1	0	0	5,635	77	5,635	77
46	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	5,482	152	0	0	5,482	152
47	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	5,479	158	5,479	158
48	PG&E Fresno 115 kV	LPRNJCTSS-GWFHANFORDSS 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	5,458	639	0	0	5,458	639
49	PG&E MorroBay 230 kV	MORROBAY-DIABLOCN 230 kV line #1	0	0	5,177	1,065	5,177	1,065
50	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line #1	4,768	220	0	0	4,768	220
51	SCE Metro	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	0	0	4,756	315	4,756	315
52	PG&E Kern 230 kV	BUENAVJ2-BITTERWATRSS 230 kV line #2	0	0	4,517	1,048	4,517	1,048
53	PG&E Manning - Metcalf 500 kV	MANNING-MNMC_SC1 500 kV line #1	4,487	94	0	0	4,487	94
54	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	4,159	250	0	0	4,159	250
55	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	3,641	146	3,641	146
56	PG&E Manning - Metcalf 500 kV	MNMC_SC2-METCALF 500 kV line #1	3,570	96	0	0	3,570	96
57	East of Pisgah-GLW/VEA	VEA_PST_2-IS TAP 138 kV line #1	2,750	444	0	0	2,750	444
58	TWE	TWE-IPP-TWE-SC1A 500 kV line #1	0	0	2,397	40	2,397	40
59	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	2,389	56	2,389	56
60	Path 46 WOR	P46 West of Colorado River (WOR)	2,348	118	0	0	2,348	118
61	PG&E Kern 230 kV	GATES D-CALFLATSSS 230 kV line #1	0	0	2,221	626	2,221	626
62	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	2,108	34	2,108	34
63	Path 41 Sylmar transformer	P41 Sylmar to SCE	2,100	180	0	0	2,100	180
64	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	2,099	901	0	0	2,099	901

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
65	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-OtayMesa-Miguel and BayBlvd-OtayMesa-Miguel 230kV	0	0	2,095	162	2,095	162
66	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line #2	0	0	1,988	7	1,988	7
67	TWE	INTERMT-TWE-IPP 345 kV line #1	0	0	1,917	53	1,917	53
68	PG&E Manning - Metcalf 500 kV	MANNING-MNMC_SC1 500 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV with SPS	1,609	97	0	0	1,609	97
69	COI Corridor	P66 COI	389	17	1,153	12	1,542	29
70	SCE Northern	VINCNT2-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	1,516	106	0	0	1,516	106
71	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	1,480	561	0	0	1,480	561
72	SCE Eastern	J.HINDS-MIRAGE 230 kV line #1	1,453	282	0	0	1,453	282
73	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	1,391	211	0	0	1,391	211
74	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	1,296	94	0	0	1,296	94
75	SCE North of Lugo	INYO 115/115 kV transformer #1	644	4,447	629	3,733	1,274	8,180
76	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	1,220	25	1,220	25
77	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	1,176	18	0	0	1,176	18
78	Path 15 Corridor	FINKSWSTA-WESTLEY 230 kV line #1	1,176	50	0	0	1,176	50
79	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	1,136	428	1,136	428
80	Path 15 Corridor	MN_GT_11-GATES 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	1,093	7	1,093	7
81	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	25	12	977	74	1,003	86
82	COI Corridor	ROUND MT-RD MT 1M 500 kV line, subject to PG&E-BANC N-1 Olinda Xfmr 500 kV	0	0	970	15	970	15
83	Path 15 Corridor	MANNING-MN_MW_21 500 kV line #2	0	0	918	4	918	4
84	PG&E Manning - Metcalf 500 kV	MNMC_SC2-METCALF 500 kV line, subject to PG&E N-1 LosBanos-Tracy 500kV	855	7	0	0	855	7
85	TWE	INTERMT-TWE-IPP 345 kV line #2	0	0	854	42	854	42
86	PG&E Manning - Metcalf 500 kV	MNMC_SC2-METCALF 500 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV with SPS	808	22	0	0	808	22
87	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	725	56	725	56
88	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	705	10	705	10
89	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line #1	0	0	544	74	544	74
90	PG&E Manning - Metcalf 500 kV	MANNING-MNMC_SC1 500 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV with SPS	493	6	0	0	493	6
91	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line #1	414	61	0	0	414	61
92	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	2	2	361	46	364	48
93	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	0	0	297	39	297	39
94	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	289	190	0	0	289	190

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
95	SCE Metro	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	281	151	281	151
96	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-2 Pit-CotwdF and CotwdE-RM 230 kV with HR SPS	274	18	0	0	274	18
97	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	264	21	0	0	264	21
98	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	243	705	243	705
99	PG&E VacaDixon 230 kV	VACA-DIX-BAHIA 230 kV line #1	226	16	0	0	226	16
100	SCE Eastern	DEVERS-devers1i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	215	224	0	0	215	224
101	SDG&E Bulk	IMPRLVLY WST 230/500 kV transformer #3	212	227	0	0	212	227
102	East of Pisgah	P61 Lugo-Victorville 500 kV Line	0	0	186	69	186	69
103	PG&E Fresno 70 kV	HURONJ-CALFLAX 70 kV line, subject to PG&E N-1 GATES D 230/70KV TB 5	0	0	184	378	184	378
104	PG&E GBA	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	182	31	0	0	182	31
105	SCE Blythe 161 kV	BLYTHE-BLYTHESC 161 kV line #1	153	4	0	0	153	4
106	SDG&E Bulk	IMPRLVLY 500/500 kV transformer #3	0	0	147	108	147	108
107	SCE Metro	MESACALS-LAGUBELL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	134	98	0	0	134	98
108	East of Pisgah-GLW/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	132	35	0	0	132	35
109	PG&E GBA	C.COSTAPPE-WINDMASTERJT 230 kV line #1	121	3	0	0	121	3
110	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	120	6	120	6
111	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	117	3	117	3
112	Path 25 PACW-PG&E 115 kV	CASCADE-DELTAP 115 kV line #1	0	0	106	10	106	10
113	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	95	14	0	0	95	14
114	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	92	11	0	0	92	11
115	PG&E Fresno 115 kV	MANCHSTR-LASPALMS_JCT 115 kV line #1	0	0	86	32	86	32
116	SCE Vincent - MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	86	19	86	19
117	PG&E Kern 230 kV	BUENAVJ2-MIDWAY-D 230 kV line #2	82	19	0	0	82	19
118	COI Corridor	FR_TM_22-FERNROADSS 500 kV line #2	80	13	0	0	80	13
119	PG&E Fresno 230 kV	WILSONPGAE-STOREYJCT2 230 kV line, subject to PG&E N-1 Storey 1-Wilson 230 kV	0	0	71	13	71	13
120	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	64	394	0	0	64	394
121	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Panoche-Manning 230 kV	64	10	0	0	64	10
122	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-2 Tesla-Tracy 500kV #1 and Tracy-LosBanos 500kV #1	64	2	0	0	64	2
123	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	58	1	1	2	59	3
124	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	57	66	57	66
125	PG&E Kern 230 kV	GATES D-TEMPLETN 230 kV line #1	0	0	48	57	48	57

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
126	SDG&E Northern 69 kV	PENDLETN-SANLUSRY 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	45	971	45	971
127	PG&E GBA	METCALF 230/500 kV transformer #13	0	0	34	1	34	1
128	SCE North of Lugo	TAP710-INYOKERN 115 kV line #1	29	14	0	0	29	14
129	East of Pisgah-GLW/VEA	SLOAN_CYN_5-ELDORDO 500 kV line #1	27	1	0	0	27	1
130	SDG&E Northern 69 kV	ESCNDIDO-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	27	4	0	0	27	4
131	PG&E Kern 230 kV	Q1593SWSTA-MIDWAY-F 230 kV line #1	1	3	25	326	26	329
132	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	25	37	25	37
133	PG&E Kern 230 kV	GATES F-Q1593SWSTA 230 kV line #1	0	0	23	119	23	119
134	SDG&E 230 kV	SILVERGT-VINE SUB 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	23	6	0	0	23	6
135	East of Pisgah-GLW/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DeservtView 230 kV with RAS	22	4	0	0	22	4
136	East of Pisgah-GLW/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Pahrump-Innovation 230kV and Pahrump-Vista 138kV with RAS	22	18	0	0	22	18
137	Path 15 Corridor	MN_MW_22-MN_MW_23 500 kV line #2	0	0	21	1	21	1
138	SCE Eastern	COLRIVER-REDBLUFF 500 kV line, subject to SCE N-1 ColoradoRiver-RedBluff 500 kV with RAS	21	30	0	0	21	30
139	COI Corridor	RM_FR_11-FERNROADSS 500 kV line #1	20	2	0	0	20	2
140	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	19	4	19	4
141	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	18	20	18	20
142	PG&E Fresno 230 kV	BELLOTA-WEBER 230 kV line, subject to PG&E N-1 Bellota-TeslaE 230kV	18	4	0	0	18	4
143	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	18	5	0	0	18	5
144	SCE Metro	MESACALS-LAGUBELL 230 kV line #2	17	114	0	0	17	114
145	East of Pisgah	BAKER-MTN PASS 115 kV line #1	0	0	17	34	17	34
146	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-1 Gregg-Borden #1 230kV	17	2	0	0	17	2
147	PG&E Fresno 230 kV	HELM-MC CALL 230 kV line, subject to PG&E N-1 Tranqlty-Helm 230kV	15	24	0	0	15	24
148	PG&E GBA	WINDMASTERJT-DELTAPMP 230 kV line #1	15	4	0	0	15	4
149	PG&E Sierra	P24 PG&E-Sierra	12	8	0	0	12	8
150	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	10	1	10	1
151	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	10	1	10	1
152	SDG&E Bulk	GR1314_18POI-IMPRLVLY 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500kV	8	3	0	0	8	3
153	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line #3	0	0	8	10	8	10
154	PG&E Fresno 115 kV	BARTON-HERNDON 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	7	3	7	3
155	SDG&E Bulk	HASSYAMP-N.GILA 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500kV	7	6	0	0	7	6
156	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	4	6	0	0	4	6

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
157	SCE Eastern	DEL_CLRVR_11-DEL_CLRVR_12 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500kV	3	1	0	0	3	1
158	SCE Eastern	DEL_CLRVR_11-DEL_CLRVR_12 500 kV line #1	3	4	0	0	3	4
159	PG&E Tesla 230 kV	TESLA C-PPASSJCT 230 kV line #2	3	1	0	0	3	1
160	SCE Metro	HINSON-DELAMO 230 kV line, subject to SCE N-2 La Fresa-Laguna Bell 230 kV #1 and La Fresa-Mesa 230 kV #1	0	0	2	18	2	18
161	SCE Metro	LAGUBELL-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #2 and Mesa-Lighthipe 230 kV	0	0	2	6	2	6
162	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line #3	0	0	2	2	2	2
163	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	1	1	0	0	1	1
164	SCE Vincent - MiraLoma 500kV	VINCENT-MESA CAL 500 kV line, subject to SCE N-2 Lugo-Mira Loma 500 kV	1	1	0	0	1	1
165	PG&E Fresno 115 kV	GWFHANFORDSS-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	1	1	0	0	1	1
166	PG&E Fresno 115 kV	MC CALL-WAHTOKE 115 kV line #1	1	1	0	0	1	1
167	SCE Lugo - Vincent 500 kV	LUGO-VINCENT 500 kV line #1	1	1	0	0	1	1

Table G.7-6 lists the aggregated congestion results across specific branch groups and local areas in the 2040 base portfolio PCM case, ranked by aggregated congestion cost.

Table G.7-6: Aggregated congestion in 2040 base portfolio PCM

No.	Aggregated congestion	Aggregated Congestion Cost ($M)	Aggregated Congestion Hours
1	Path 15 Corridor	1,818.11	10,345
2	Path 26 Corridor	328.88	4,557
3	SCE Northern	237.67	4,930
4	Path 65 PDCI	153.20	4,300
5	SCE Metro	148.55	4,425
6	East of Pisgah-GLW/VEA	120.88	6,945
7	PG&E GBA	109.80	4,512
8	PG&E Las Aguilas - Moss Landing 230 kV	67.98	1,777
9	SCE Lugo - Rancho Vista 500 kV	64.76	996
10	SCE North of Lugo	62.93	15,240
11	PG&E Fresno 230 kV	38.25	2,799
12	SWIP North	30.44	358
13	PG&E North Valley 230 kV	25.79	1,752
14	PG&E Tesla 230 kV	24.18	891
15	SDG&E/CFE	18.72	1,761
16	PG&E Fresno 115 kV	16.13	921
17	SCE Eastern	14.27	1,670
18	PG&E Manning - Metcalf 500 kV	11.82	322
19	TWE	10.80	212

No.	Aggregated congestion	Aggregated Congestion Cost ($M)	Aggregated Congestion Hours
20	Path15 Corridor	8.72	354
21	SDG&E Bulk	8.22	855
22	PG&E Kern 230 kV	6.92	2,198
23	PG&E MorroBay 230 kV	5.18	1,065
24	SDG&E 230 kV	5.04	1,285
25	COI Corridor	2.61	59
26	Path 46 WOR	2.35	118
27	Path 41 Sylmar transformer	2.10	180
28	SCE Antelope 66kV	2.10	901
29	PG&E POE - RIO OSO 230 kV	1.30	94
30	PG&E Collinsville corridor	0.56	94
31	East of Pisgah	0.39	134
32	Path 25 PACW-PG&E 115 kV	0.37	31
33	PG&E VacaDixon 230 kV	0.23	16
34	PG&E Fresno 70 kV	0.18	378
35	SCE Blythe 161 kV	0.15	4
36	SDG&E Northern 69 kV	0.14	1,369
37	SCE Vincent - MiraLoma 500kV	0.09	20
38	PG&E Sierra	0.07	11
39	Moenkope - Eldorado 500 kV	0.02	5
40	SCE Lugo - Vincent 500 kV	0.00	1

G.7.5 2040 Base Portfolio PCM Curtailment Results

Table G.7-7 shows the wind and solar curtailment results of the 2040 base portfolio PCM. Renewable curtailment in this planning cycle's PCM results was mainly observed in the areas where transmission congestion occurred. The overall renewable curtailment remained at similar level as in the previous planning cycle.

Table G.7-7: Wind and solar curtailment summary in the 2040 base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
PG&E Fresno	39,586	6,658	46,244	14.40%
SCE Northern	39,848	2,003	41,852	4.79%
SCE Eastern	30,756	1,135	31,891	3.56%
NM	27,939	469	28,408	1.65%
SCE EOP, GLW/VEA	21,953	1,888	23,841	7.92%
PG&E Kern	17,436	2,239	19,676	11.38%
SDGE East of Miguel	18,887	261	19,148	1.36%
WY	17,868	346	18,214	1.90%
OSW-Diablo Canyon	12,273	1,861	14,134	13.17%
SCE NOL	11,219	1,142	12,361	9.24%
OSW-Humboldt	8,198	5	8,203	0.06%
PG&E Greater Bay Area	7,552	12	7,564	0.16%
PG&E Central Valley	5,623	5	5,628	0.09%

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
PG&E N. Valley	4,508	35	4,543	0.77%
NW	4,190	4	4,194	0.09%
AZ	3,063	59	3,122	1.91%
ID	3,025	25	3,050	0.82%
IID	1,717	18	1,735	1.07%
BANC	408	0	408	0.00%
PG&E N. Coast	379	0	379	0.02%
NV	372	5	376	1.24%
San Diego	278	0	279	0.13%
SCE Metro	260	5	265	1.92%
PG&E North Bay	67	0	67	0.00%
Total	**277,408**	**18,177**	**295,585**	**6.15%**

G.7.6 2040 Base Portfolio PCM Gas-fired Generator Utilization

The average capacity factors of gas-fired generators by area in the 2040 base portfolio were summarized in Table G.7-8. The capacity factors increased in this planning cycle due to the increase in data center load and battery. The removal of the Del Amo project also contributed to the gas-fired generator capacity factor increase in the southern California areas.

Table G.7-8: Gas-fired generator utilization in the 2040 base portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,219	4,690,456	0.24
PG&E Central Valley	840	1,656,417	0.18
PG&E Fresno	1,230	1,961,874	0.18
PG&E Greater Bay Area	5,407	18,824,736	0.34
PG&E Humboldt	163	211,322	0.15
PG&E Kern	2,719	7,928,485	0.21
PG&E North Valley	1,450	3,910,624	0.24
SCE Blythe	263	1,467,550	0.64
SCE Eastern LA Basin	2,363	5,010,780	0.34
SCE Eldorado	525	1,323,677	0.29
SCE North of Lugo	935	2,602,486	0.34
SCE North of Magunden	56	52,909	0.29
SCE South of Magunden	1,119	2,650,621	0.27
SCE Tehachapi	4	5,468	0.16
SCE Ventura	164	134,680	0.11
SCE Western LA Basin	3,524	8,550,902	0.22
SDG&E Bulk	1,004	2,376,017	0.26
SDG&E San Diego	2,709	4,592,013	0.19
System Total	**25,693**	**67,951,017**	**0.30**

G.7.7 2035 Sensitivity Portfolio PCM Congestion Results

The results of the congestion assessment in the 2035 sensitivity portfolio PCM is listed in Table G.7-9. Columns "Cost Forward" and "Duration Forward" are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns "Cost Backward" and "Duration Backward" are the cost and duration of congestion, respectively, when flow is in backward direction.

Table G.7-9: Congestion in the ISO-controlled grid in the 2035 sensitivity portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	1,014,702	3,734	1,014,702	3,734
2	Path 15 Corridor	MANNING-MN_GT_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	305,545	2,391	305,545	2,391
3	PG&E MorroBay 230 kV	TEMPLETN-MORROBAY 230 kV line #1	0	0	236,523	4,584	236,523	4,584
4	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	229,588	2,339	229,588	2,339
5	Path 26 Corridor	P26 Northern-Southern California	405	22	170,242	1,900	170,647	1,922
6	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	125,382	4,201	125,382	4,201
7	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	49,113	884	124	25	49,237	909
8	East of Pisgah-GLW/VEA	GAMEBIRD-PAHRUMP 138 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	0	0	43,492	3,900	43,492	3,900
9	PG&E Kern 230 kV	GATES D-TEMPLETN 230 kV line #1	0	0	40,870	970	40,870	970
10	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	37,267	468	37,267	468
11	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	33,456	284	33,456	284
12	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	31,429	293	31,429	293
13	PG&E Kern 230 kV	GATES D-CALFLATSSS 230 kV line #1	0	0	28,096	2,253	28,096	2,253
14	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	26,208	442	26,208	442
15	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	21,412	1,756	0	0	21,412	1,756
16	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	17,931	51	17,931	51
17	SDG&E/CFE	P45 SDG&E-CFE	3,536	699	13,858	574	17,394	1,273
18	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	15,575	172	15,575	172
19	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	12,703	203	12,703	203
20	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	12,464	58	12,464	58
21	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	12,393	911	0	0	12,393	911
22	Path 15 Corridor	GATES-GT_MW_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	10,918	269	10,918	269
23	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	7,133	574	7,133	574
24	PG&E GBA	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	7,091	170	7,091	170
25	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	6,155	365	6,155	365
26	COI Corridor	P66 COI	2,711	74	3,087	62	5,799	136
27	Path 15 Corridor	MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	5,514	126	5,514	126
28	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	5,421	117	5,421	117
29	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	4,604	84	4,604	84
30	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	4,492	505	4,492	505

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
31	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	4,216	255	4,216	255
32	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	3,850	53	3,850	53
33	TWE	TWE-IPP-TWE-SC1A 500 kV line #1	0	0	3,321	46	3,321	46
34	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	3,294	1,131	0	0	3,294	1,131
35	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-1 Tesla-Tracy 500kV #1	3,200	133	0	0	3,200	133
36	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	3,069	197	0	0	3,069	197
37	PG&E Fresno 115 kV	LPRNJCTSS-GWFHANFORDSS 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	2,631	590	0	0	2,631	590
38	SCE Northern	PARDEE-VINCENT 230 kV line, subject to SCE N-2 Vincent2-SClara #1 and Antelope-Pardee #1 230 kV	0	0	2,398	275	2,398	275
39	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-OtayMesa-Miguel and BayBlvd-OtayMesa-Miguel 230kV	0	0	2,318	161	2,318	161
40	TWE	TWE-SC1B-TWE-CRYS 500 kV line #1	0	0	1,996	27	1,996	27
41	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	1,765	28	0	0	1,765	28
42	SCE North of Lugo	INYO 115/115 kV transformer #1	703	3,950	746	4,195	1,449	8,145
43	PG&E Fresno 115 kV	MANCHSTR-HERNDON 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	1,397	40	1,397	40
44	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	1,211	104	1,211	104
45	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	1,162	101	0	0	1,162	101
46	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	0	0	1,084	131	1,084	131
47	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	1,038	35	1,038	35
48	Path 46 WOR	P46 West of Colorado River (WOR)	1,038	35	0	0	1,038	35
49	Path 41 Sylmar transformer	P41 Sylmar to SCE	1,033	103	0	0	1,033	103
50	SCE Lugo - Rancho Vista 500 kV	LUGO-RANCHVST 500 kV line, subject to SCE N-2 Lugo-Mira Loma 500 kV	989	91	0	0	989	91
51	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	948	71	0	0	948	71
52	SCE Metro	BARRE-LEWIS 230 kV line #1	0	0	905	234	905	234
53	SCE Eastern	J.HINDS-MIRAGE 230 kV line #1	792	118	0	0	792	118
54	TWE	INTERMT-TWE-IPP 345 kV line #1	0	0	776	9	776	9
55	PG&E Tesla 230 kV	TRCY PMP-TESLA D 230 kV line, subject to PG&E-BANC N-2 Tesla-Tracy 500kV #1 and Tracy-LosBanos 500kV #1	583	43	0	0	583	43
56	PG&E GBA	SANJOSEB230 230/115 kV transformer #1	543	161	0	0	543	161
57	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	530	15	530	15
58	East of Pisgah-GLW/VEA	VEA_PST_2-IS TAP 138 kV line #1	430	111	0	0	430	111
59	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	367	30	367	30
60	PG&E GBA	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	347	88	0	0	347	88
61	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	329	11	0	0	329	11
62	PG&E MorroBay 230 kV	MORROBAY-ESTRELLA 230 kV line #1	282	30	0	0	282	30
63	TWE	INTERMT-TWE-IPP 345 kV line #2	0	0	282	2	282	2
64	SDG&E Bulk	IMPRLVLY WST 230/500 kV transformer #3	276	282	0	0	276	282
65	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	214	43	0	0	214	43
66	SCE Metro	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	0	0	208	26	208	26
67	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	207	17	0	0	207	17

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
68	COI Corridor	FERNROADSS-RM_TM_22 500 kV line #2	161	2	0	0	161	2
69	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	148	24	148	24
70	COI Corridor	FR_TM_22-FERNROADSS 500 kV line #2	138	12	0	0	138	12
71	PG&E GBA	VASCOWINDJCT-CAYETANO 230 kV line #1	126	26	0	0	126	26
72	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	121	31	0	0	121	31
73	Path 25 PACW-PG&E 115 kV	CASCADE-DELTAP 115 kV line #1	0	0	120	10	120	10
74	PG&E MorroBay 230 kV	MORROBAY-DIABLOCN 230 kV line #1	0	0	110	38	110	38
75	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	0	0	108	29	108	29
76	East of Pisgah	P61 Lugo-Victorville 500 kV Line	0	0	92	29	92	29
77	SDG&E Bulk	IMPRLVLY 500/500 kV transformer #3	0	0	92	82	92	82
78	SCE Eastern	JHINDMWD-EAGLEMTN 230 kV line #1	87	12	0	0	87	12
79	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	81	107	81	107
80	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	76	82	76	82
81	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	71	10	71	10
82	PG&E Kern 230 kV	GATES F-ARCO 230 kV line #1	0	0	70	175	70	175
83	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	0	0	69	23	69	23
84	COI Corridor	RM_FR_11-FERNROADSS 500 kV line #1	0	0	68	3	68	3
85	PG&E Kern 230 kV	GATES F-Q1593SWSTA 230 kV line #1	0	0	60	186	60	186
86	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	59	5	0	0	59	5
87	SDG&E Bulk	HASSYAMP-N.GILA 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500kV	58	1	0	0	58	1
88	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line #3	0	0	57	19	57	19
89	SCE Northern	VINCNT2-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	46	10	0	0	46	10
90	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	43	2	43	2
91	PG&E VacaDixon 230 kV	VACA-DIX-BAHIA 230 kV line #1	36	6	0	0	36	6
92	SCE Eastern	DVRS_RB_11-DVRS_RB_12 500 kV line #1	0	0	35	2	35	2
93	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	32	7	32	7
94	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	32	12	32	12
95	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	32	23	32	23
96	SCE Eastern	DEVERS-devers1i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	31	88	0	0	31	88
97	PG&E Sierra	P24 PG&E-Sierra	30	15	0	0	30	15
98	PG&E GBA	MORAGA-CASTROVL 230 kV line #1	28	7	0	0	28	7
99	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	28	6	0	0	28	6
100	SCE Vincent - MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	27	16	27	16
101	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	27	3	0	0	27	3
102	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	26	8	0	0	26	8
103	PG&E Kern 230 kV	Q1593SWSTA-MIDWAY-F 230 kV line #1	0	1	20	206	20	207
104	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line #1	0	0	20	30	20	30
105	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	19	18	19	18
106	PG&E North Valley 230 kV	LAKEVILE-T22_93 230 kV line #1	0	0	19	5	19	5

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
107	PG&E North Valley 230 kV	T22_93-FULTON 230 kV line #1	0	0	19	4	19	4
108	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	17	1	17	1
109	SDG&E Northern 69 kV	PENDLETN-SANLUSRY 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	17	386	17	386
110	SCE North of Lugo	TAP710-INYOKERN 115 kV line #1	14	9	0	0	14	9
111	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	13	151	0	0	13	151
112	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	12	11	12	11
113	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	11	2	0	0	11	2
114	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	7	4	7	4
115	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line #3	0	0	7	2	7	2
116	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	5	3	0	0	5	3
117	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line #1	4	1	0	0	4	1
118	Path 15 Corridor	MANNING-MN_MW_21 500 kV line #2	0	0	4	1	4	1
119	PG&E GBA	NRS-TRIMBLE 230 kV line #1	0	0	3	3	3	3
120	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-2 LoganCR-Delevn and Delevn-Cortina 230 kV with SPS	3	12	0	0	3	12
121	Path 42	P42 IID-SCE	3	6	0	0	3	6
122	SCE Vincent - MiraLoma 500kV	VINCENT-MESA CAL 500 kV line, subject to SCE N-2 Lugo-Mira Loma 500 kV	2	1	0	0	2	1
123	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	2	1	0	0	2	1
124	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	2	6	2	6
125	SCE Alberhill - Serrano 500 kV	ALBERHIL-SERRANO 500 kV line #1	1	4	0	0	1	4
126	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-1 Delevn-Cortina 230 kV with SPS	1	4	0	0	1	4
127	PG&E GBA	WINDMASTERJT-DELTAPMP 230 kV line #1	1	3	0	0	1	3
128	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	1	1	0	0	1	1
129	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	1	1	0	0	1	1
130	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	1	1	0	0	1	1
131	SCE Eastern	COLRIVER-REDBLUFF 500 kV line, subject to SCE N-1 ColoradoRiver-RedBluff 500 kV with RAS	1	1	0	0	1	1

Table G.7-10 lists the aggregated congestion results across specific branch groups and local areas in the 2035 sensitivity portfolio PCM case, ranked by aggregated congestion cost.

Table G.7-10: Aggregated congestion in 2035 sensitivity portfolio PCM

No.	Aggregated congestion	Aggregated Congestion Cost ($M)	Aggregated Congestion Hours
1	Path 15 Corridor	1,682.47	10,458
2	Path 26 Corridor	281.76	4,102
3	PG&E MorroBay 230 kV	236.92	4,652
4	Path 65 PDCI	125.38	4,201
5	PG&E Kern 230 kV	69.12	3,791
6	East of Pisgah-GLW/VEA	43.92	4,011
7	SCE North of Lugo	35.27	10,821
8	SCE Metro	34.57	544
9	SDG&E/CFE	21.10	1,590
10	SCE Northern	9.96	905
11	PG&E GBA	9.42	540
12	SCE Eastern	6.43	781
13	TWE	6.37	84
14	COI Corridor	6.17	153
15	SWIP North	4.60	84
16	PG&E Fresno 115 kV	4.10	640
17	PG&E Tesla 230 kV	3.78	176
18	SCE Antelope 66kV	3.29	1,131
19	PG&E POE - RIO OSO 230 kV	1.16	101
20	SDG&E 230 kV	1.12	124
21	PG&E Sierra	1.11	146
22	Path 46 WOR	1.04	35
23	Path 41 Sylmar transformer	1.03	103
24	SCE Lugo - Rancho Vista 500 kV	0.99	91
25	SDG&E Bulk	0.64	408
26	Path 25 PACW-PG&E 115 kV	0.33	27
27	PG&E North Valley 230 kV	0.19	50
28	East of Pisgah	0.13	36
29	PG&E Collinsville corridor	0.05	53
30	PG&E VacaDixon 230 kV	0.04	6
31	SDG&E Northern 69 kV	0.03	537
32	SCE Vincent - MiraLoma 500kV	0.03	17
33	Moenkope - Eldorado 500 kV	0.03	6
34	PG&E Fresno 230 kV	0.03	8
35	Path 42	0.00	6
36	SCE Alberhill - Serrano 500 kV	0.00	4

G.7.8 2035 Sensitivity Portfolio PCM Curtailment Results

Table G.7-11 shows the wind and solar curtailment results of the 2035 sensitivity portfolio PCM.

Table G.7-11: Wind and solar curtailment summary in the 2035 sensitivity portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	33,712	561	34,274	1.64%
SCE Eastern	25,274	68	25,343	0.27%
OSW-Diablo Canyon	18,101	5,464	23,565	23.19%
NM	19,919	169	20,088	0.84%
PG&E Fresno	18,193	1,055	19,248	5.48%
SDGE East of Miguel	14,790	8	14,797	0.05%
OSW-Humboldt	13,680	0	13,680	0.00%
PG&E Kern	12,679	810	13,488	6.00%
SCE EOP, GLW/VEA	12,307	37	12,344	0.30%
WY	11,160	50	11,210	0.44%
SCE NOL	8,954	203	9,156	2.21%
PG&E Greater Bay Area	6,674	0	6,674	0.00%
NW	3,979	0	3,979	0.00%
AZ	3,087	36	3,122	1.14%
ID	2,934	5	2,939	0.19%
PG&E Central Valley	2,385	0	2,385	0.00%
PG&E N. Valley	1,884	0	1,884	0.00%
IID	1,728	8	1,735	0.44%
BANC	408	0	408	0.00%
NV	375	1	376	0.32%
SCE Metro	265	0	265	0.01%
San Diego	253	0	253	0.00%
PG&E N. Coast	35	0	35	0.00%
PG&E North Bay	2	0	2	0.00%
SCE Northern	33,712	561	34,274	1.64%
Total	**212,778**	**8,473**	**221,251**	**3.83%**

G.7.9 2035 Sensitivity Portfolio PCM Gas-fired Generator Utilization

The average capacity factors of gas-fired generators by area in the 2035 sensitivity portfolio were summarized in Table G.7-12.

Table G.7-12: Gas-fired generator utilization in the 2035 sensitivity portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,259	5,074,731	0.22
PG&E Central Valley	840	1,305,969	0.14
PG&E Fresno	1,230	1,964,065	0.18
PG&E Greater Bay Area	5,680	18,401,016	0.31
PG&E Humboldt	163	152,273	0.11
PG&E Kern	2,972	8,523,486	0.20
PG&E North Valley	1,491	3,381,628	0.22
SCE Blythe	263	1,617,332	0.70
SCE Eastern LA Basin	2,620	5,215,518	0.27
SCE Eldorado	525	1,403,716	0.31
SCE North of Lugo	980	2,803,344	0.35

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
SCE North of Magunden	56	44,951	0.31
SCE South of Magunden	1,119	2,490,089	0.25
SCE Tehachapi	4	3,120	0.09
SCE Ventura	259	356,349	0.15
SCE Western LA Basin	4,060	10,377,120	0.21
SDG&E Bulk	1,004	2,324,646	0.25
SDG&E San Diego	2,712	4,094,408	0.16
System Total	**27,237**	**69,533,761**	**0.29**

G.8 Economic Planning Study Requests

G.8.1 Study request for Pacific Transmission Expansion (PTE) project

Study request overview

California Western Grid Development, LLC (Cal Western) submitted the Pacific Transmission Expansion Project (PTE) for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes a 2,000 MW controllable high-voltage direct current (HVDC) subsea transmission system to interconnect Northern and Southern California, with converter stations near Diablo Canyon or Morro Bay and El Segundo. PTEP is designed to enhance statewide transfer capability, reduce congestion, and displace local fossil generation in constrained load areas, particularly within the West Los Angeles Basin.

The project supports California's long-term decarbonization, reliability, and resource adequacy goals. It is consistent with Senate Bill (SB) 887, enabling delivery of renewable energy to major load centers, reducing dependence on gas-fired resources, and improving air quality. PTEP is proposed as a multi-value project (MVP) that offers combined economic, reliability, and public policy benefits across the CAISO grid.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-1.

Table G.8-1: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduces congestion between Northern and Southern California by creating a 2,000 MW controllable HVDC transfer path.	Consistent with CAISO previous analysis; project expected to relieve congestion on Path 26 and in the LA Basin area

Benefits category	Benefits stated in submission	ISO evaluation
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enables delivery of offshore wind and Central Coast renewable resources to Southern California.	Supports integration of offshore and Central Coast renewables.
Local Capacity Area Resource requirements	Reduces West LA Basin Local Capacity Requirement (LCR) by up to 2,000 MW.	CAISO confirms potential for LCR reduction based on comparable configurations studied in prior planning cycles; magnitude to be verified in detailed modeling.
Increase in Identified Congestion	No increase anticipated; HVDC design allows controlled power flow and congestion management.	No adverse congestion impacts expected; controllability enhances transfer efficiency and grid stability.
Integrate New Generation Resources or Loads	Facilitates integration of new renewable and storage projects statewide.	Helps to integrate offshore wind and energy storage.
Other	Provides public policy benefits, including improved air quality, reduced wildfire exposure, and displacement of gas-fired generation.	Qualitative benefits acknowledged

Conclusion

Based on the congestion analysis results and evaluation provided above, the PTE project was selected for detailed analysis as an alternative for mitigating Path 26 congestion and Western LA Basin congestion in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.2 Study request for Fort Churchill – Tesla 500 kV Line Project

Study request overview

GridLiance West (GLW) submitted the Fort Churchill – Tesla 500 kV Line Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes a new 500 kV transmission line connecting NV Energy's Fort Churchill Substation (Walker River) to PG&E's Tesla Substation, rated at approximately 3,000 MVA with 70 percent series compensation. The proposed line would enhance import capabilities into PG&E's Greater Bay Area, reduce congestion along Path 15, and improve interregional reliability between CAISO and NV Energy.

GLW notes that 8.7 GW of renewable resources are currently in NV Energy's interconnection queue, including solar, wind, geothermal, and battery storage projects. The Fort Churchill – Tesla line would create a new import corridor to deliver these geographically diverse resources to California, helping achieve statewide renewable energy, reliability, and resource adequacy goals.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-2.

Table G.8-2: Evaluating study request – Fort Churchill – Tesla 500kV Line Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduces congestion along Path 15 and adjacent Bay Area corridors by adding 500 kV import capacity.	May help to reduce congestion on the Path 15 corridor
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Provides access to 8.7 GW of renewable generation from NV Energy's queue, including solar, wind, geothermal, and storage.	Potentially supports integration of Nevada renewables but requires clarity of Nevada renewable assumption in CPUC portfolio.
Local Capacity Area Resource requirements	Enhances import capability to the Greater Bay Area, potentially reducing reliance on local generation.	Not identified.
Increase in Identified Congestion	Not expected to increase congestion; provides new high-capacity redundancy.	Potentially increases congestion in the 230 kV system from Tesla to the Greater Bay area
Integrate New Generation Resources or Loads	Facilitates import of Nevada-based renewable energy to support California's clean energy goals.	Potentially supports integration of Nevada renewables but requires clarity of Nevada renewable assumption in CPUC portfolio.
Other	Improves grid reliability and resilience through interregional connectivity with NV Energy.	Not identified.

Conclusion

This project potentially supports integration of Nevada renewables but requires clarity of Nevada renewable assumption in CPUC portfolios. No detailed production cost simulation was conducted for this study request in this planning cycle.

G.8.3 Study request for Sloan Canyon – Mead 230 kV and Mead – Crystal – Navajo – Shiprock – Four Corners 500 kV Project

Study request overview

GridLiance West (GLW) submitted the Sloan Canyon – Mead 230 kV and Mead – Crystal – Navajo – Shiprock – Four Corners 500 kV Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes a new 230 kV line from GLW's Sloan Canyon Substation to WAPA's Mead Substation, and a new 500 kV transmission corridor extending from Mead to NV Energy's Crystal Substation, continuing east to Navajo, Shiprock, and Four Corners substations in Arizona and New Mexico.

The project is designed to enhance interregional transfer capability, reduce congestion, and increase renewable energy import capacity into California. It provides access to over 560 GW of wind potential identified in Arizona and New Mexico by NREL and supports the

California Public Utilities Commission's (CPUC) 2025–2026 resource portfolio, which prioritizes out-of-state wind procurement to meet renewable energy targets. The proposed upgrades also enhance system resilience and enable greater coordination with WAPA, NV Energy, and the Southwest Power Pool (SPP).

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-3.

Table G.8-3: Evaluating study request – Sloan Canyon – Mead 230 kV and Mead – Crystal – Navajo – Shiprock – Four Corners 500 kV Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduce congestion East of Pisgah and along interregional corridors by providing new 230 kV and 500 kV paths.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the VEA 138 kV system. The Sloan Canyon – Mead Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enables delivery of renewable generation from Arizona and New Mexico (estimated 560 GW wind potential).	Potentially supports integration of renewables in Nevada, Arizona, and New Mexico but requires clarity of renewable assumptions in the CPUC portfolio
Local Capacity Area Resource requirements	Increases import flexibility and reduces local generation dependency.	Not identified
Increase in Identified Congestion	No increase anticipated; project designed to relieve multiple regional bottlenecks.	Not identified
Integrate New Generation Resources or Loads	Integrates new renewable resources and strengthens CAISO's coordination with WAPA and SPP.	Potentially supports integration of renewables in Nevada, Arizona, and New Mexico but requires clarity of renewable assumptions in the CPUC portfolio
Other	Improves reliability, contingency performance, and grid resilience through enhanced interregional connectivity.	Not identified

Conclusion

The projects in this study request potentially supports integration of Nevada, Arizona, and New Mexico renewables but requires clarity of Nevada renewable assumption in CPUC portfolios. No detailed production cost simulation was conducted for this study request in this planning cycle.

G.8.4 Study request for Western Bounty – GLW Esmeralda Interconnection Project

Study request overview

GridLiance West (GLW) submitted the Western Bounty – GLW Esmeralda Interconnection Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes to interconnect the Western Bounty Transmission System with the GLW network at Esmeralda, creating a coordinated regional transmission pathway to improve access to renewable resources in Oregon, Idaho, and Nevada.

The project scope includes upgrading several existing 230 kV corridors to 500 kV, constructing new 500 kV lines between Beatty, Esmeralda, and Lugo substations, and expanding substations at Johnnie Corner, Lathrop Wells, and Beatty. This interconnection provides an AC-based alternative to one of the Western Bounty HVDC segments, deferring its development while maintaining transfer capability into the Los Angeles Basin. The project supports system reliability, renewable integration, and congestion relief by optimizing use of GLW's existing and planned infrastructure.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-4.

Table G.8-4: Evaluating study request – Western Bounty – GLW Esmeralda Interconnection Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Relieves congestion in southern Nevada and east of Pisgah by adding new 500 kV AC capacity.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the VEA 138 kV system. The Sloan Canyon – Mead Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enables delivery of 1.7 GW of Oregon wind, 2 GW of Idaho solar and storage, and 8.7 GW of Nevada renewables.	Potentially supports integration of renewables in Nevada and Idaho but requires clarity of renewable assumptions in the CPUC portfolio
Local Capacity Area Resource requirements	Enhances import capability into the LA Basin, reducing reliance on local thermal generation.	Not identified
Increase in Identified Congestion	Not expected; project adds redundancy and system flexibility.	Not identified
Integrate New Generation Resources or Loads	Provides new interregional access between CAISO and adjacent balancing authorities.	Not identified
Other	Offers contingency and resilience benefits through multiple interconnection paths.	Not identified

Conclusion

No significant congestion was observed in the GridLiance West/VEA area. Potentially supports integration of renewables in Nevada and Idaho but requires clarity of renewable assumptions in the CPUC portfolio. No detailed production cost simulation was conducted for this study request in this planning cycle.

G.8.5 Study request for Monarch 500 kV Transmission Project

Study request overview

Golden State Clean Energy (GSCE) submitted the Monarch 500 kV Transmission Project (Monarch) for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes a 500 kV transmission upgrade along the Path 15 corridor to reduce congestion and improve transfer capability between Central California and the Bay Area. Monarch is also under evaluation by the Western Area Power Administration (WAPA) Sierra Nevada Region (SNR) in connection with solar and storage projects located in Fresno County within the WAPA SNR interconnection queue.

The proposed line complements the Manning–Moss Landing 500 kV upgrade and would strengthen north–south transmission flows across one of CAISO's most congested corridors. The project supports Fresno-area renewable development, enhances import flexibility, and provides a cost-effective solution to congestion identified in CAISO's 2024–2025 Transmission Plan. Monarch aligns with the 20-Year Transmission Outlook (2024), which identified the Path 15 and the Las Aguilas – Moss Landing 230 kV corridors as critical reinforcement areas for long-term economic, reliability, and policy-driven needs.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-5.

Table G.8-5: Evaluating study request – Monarch 500 kV Transmission Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduces congestion along Path 15 and the Las Aguilas – Moss Landing 230 kV line identified in the 2024–2025 TPP.	Path 15 corridor congestion was observed in this planning cycle. This project can help to relieve congestion on the segments of north of Manning Las Aguilas – Moss Landing 230 kV line, and Manning – Metcalf 500 kV line
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enhances transmission capacity for Fresno-area solar and storage projects to serve Bay Area load centers.	Potentially supports integration of renewables in the PG&E Fresno and Kern area

Local Capacity Area Resource requirements	Increases import flexibility and reduces reliance on local generation.	Not identified
Increase in Identified Congestion	Not expected to increase congestion; strengthens existing north–south infrastructure.	Potentially increase congestion on the transmission lines south of Manning
Integrate New Generation Resources or Loads	Enables coordination between CAISO and WAPA to integrate solar and storage resources within SNR.	Potentially supports integration of renewables in the PG&E Fresno area
Other	Provides a long-term, cost-effective regional transmission solution that meets policy and reliability needs.	Not identified.

Conclusion

Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles with considering different alternatives, as set out in Section G.9.

G.8.6 Study request for Kern-Southland Energy Link (K-SEL) Project

Study request overview

Grid United LLC, on behalf of Kern–Southland Energy Link LLC (K-SEL), submitted the K-SEL Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes to repurpose an existing underground oil and gas pipeline corridor to host a below-grade ±500 kV HVDC transmission system, establishing a controllable link between Midway Substation in Kern County and load centers in the Los Angeles Basin. The proposed 2 GW HVDC tie would deliver low-cost, full capacity deliverability status (FCDS) renewable resources into Southern California, improving import flexibility and grid reliability.

K-SEL is designed to reduce congestion on Path 26, enhance north–south transfer capability, and lessen reliance on Aliso Canyon gas storage. The underground configuration minimizes environmental impact while providing additional system voltage support and stability to the coastal LA Basin. The project represents a multi-value investment offering economic, reliability, and public-policy benefits through better utilization of existing infrastructure.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request were summarized in Table G.8-6.

Table G.8-6: Evaluating study request – Kern-Southland Energy Link (K-SEL) Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduces congestion on Path 26, which experienced ~3,500 hours and $72 million in congestion during the 2023–2024 TPP.	The Midway to El Nido underground HVDC project can help to mitigate congestion in the SCE's Western LA Basin area, and to reduce congestion in the Path 26 corridor
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Provides a 2 GW path for Kern County renewable generation to reach the LA Basin.	Potentially supports integration of renewables in the PG&E Fresno and Kern area.
Local Capacity Area Resource requirements	Reduces West LA Basin LCR and reliance on Aliso Canyon storage by enhancing import capability.	The Midway to El Nido underground HVDC project can help to reduce local capacity requirement in the SCE's LA Basin area.
Increase in Identified Congestion	Not expected to increase congestion; HVDC design manages flow dynamically.	Not identified
Integrate New Generation Resources or Loads	Enables delivery of low-cost FCDS renewables from the Central Valley.	Potentially supports integration of renewables in the PG&E Fresno and Kern area.
Other	Uses existing pipeline ROW, reducing environmental impact and construction costs.	Not identified

Conclusion

Based on the congestion analysis results and evaluation provided above, the Midway to El Nido underground HVDC project was selected for detailed analysis as an alternative for mitigating SCE's Western LA Basin and Path 26 congestions in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.7 Study request for Captain Jack – Fern Road 500 kV Project

Study request overview

Horizon West Transmission (HWT) submitted the Captain Jack – Fern Road 500 kV Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The proposed project consists of a new 112-mile 500 kV transmission line between Captain Jack and Fern Road substations, rated 3,291/3,880 MVA with 70% series compensation.

The objective of this project is to provide a flexible and resilient transmission alternative in response to potential delays in Offshore Wind (OSW) development. By reallocating capacity initially reserved for OSW to Oregon wind resources, the project enhances renewable energy delivery to the Bay Area. Oregon wind potential, estimated at 297 GW by the National Renewable Energy Laboratory (NREL), presents an opportunity to strengthen resource diversity and reliability. This line would optimize utilization of existing OSW transmission capacity while maintaining progress toward California's renewable and reliability goals.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-7.

Table G.8-7: Evaluating study request – Captain Jack – Fern Road 500 kV Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduces congestion by providing an alternative renewable delivery path to the Bay Area.	No significant congestion was observed along the COI corridor in this planning cycle
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enables access to Oregon wind resources (up to 6 GW in BPA queue; 297 GW potential per NREL).	Potentially support integration of renewables in the Northwest areas and offshore wind but requires clarity of renewable assumption in the CPUC portfolio.
Local Capacity Area Resource requirements	Improves Bay Area reliability and Resource Adequacy by supplementing OSW capacity.	Not identified
Increase in Identified Congestion	No increase expected; project enhances grid flexibility.	Not identified
Integrate New Generation Resources or Loads	Integrates Oregon wind into the CAISO system via Captain Jack.	Potentially support integration of renewables in the Northwest areas and offshore wind but requires clarity of renewable assumption in the CPUC portfolio.
Other	Enhances resilience and ensures renewable deliverability under OSW delays.	Not identified

Conclusion

This project potentially supports integration of Northwest renewables and offshore wind but requires clarity of renewable assumption in CPUC portfolios. No detailed production cost simulation was conducted for this study request in this planning cycle.

G.8.8 Study request for Cielo Azul – Imperial Valley 500 kV Project

Study request overview

Horizon West Transmission (HWT) submitted the Cielo Azul – Imperial Valley 500 kV Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The proposed project consists of a new 165-mile, 500 kV transmission line connecting the Cielo Azul Substation to the Imperial Valley Substation, rated 3,291/3,880 MVA with 70% series compensation.

The purpose of this project is to address deliverability constraints in the SCE Eastern Area and enhance access to New Mexico wind resources identified in the CPUC's 2045 20-Year Transmission Outlook, which mapped approximately 5.2 GW of new wind generation in the region. The project provides a new outlet for these resources, improves transmission reliability, and mitigates congestion identified in the 2024–2025 CAISO TPP Policy

Assessment, including constraints on the Devers–Red Bluff 500 kV lines. The proposed connection supports resource adequacy, renewable integration, and system resilience by leveraging existing and planned infrastructure in Southern California.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-8.

Table G.8-8: Evaluating study request – Cielo Azul – Imperial Valley 500 kV Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Alleviates congestion in the SCE Eastern Area and along the Devers–Red Bluff 500 kV corridor.	No significant congestion was observed in the SCE Eastern area and the SDG&E Imperial Valley area.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Enables delivery of 5.2 GW of New Mexico wind resources identified in CPUC portfolios.	Not identified
Local Capacity Area Resource requirements	Improves Resource Adequacy and import flexibility for SCE's Eastern Area.	Not identified
Increase in Identified Congestion	No increase anticipated; line mitigates deliverability constraints.	Not identified
Integrate New Generation Resources or Loads	Provides substation interconnection flexibility and supports new renewable integration.	Not identified
Other	Enhances reliability and resilience through redundancy and reduced dependence on existing lines.	Not identified

Conclusion

This project potentially helps to balance flow between the SCE Eastern and SDG&E Imperial Valley areas. Since no significant congestion was observed in these two areas, no detailed production cost simulation was conducted for this study request in this planning cycle.

G.8.9 Study request for Midway – Pastoria – Whirlwind 500 kV Project

Study request overview

Horizon West Transmission (HWT) submitted the Midway – Pastoria – Whirlwind 500 kV Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The project proposes the development of a new Pastoria 500 kV Substation equipped with a 500/230 kV transformer, and construction of two new 500 kV transmission lines: one 37-mile line from Midway to Pastoria and another 26-mile line from Pastoria to Whirlwind, each rated at 3,291/3,880 MVA.

The project aims to mitigate Path 26 congestion—a major north–south bottleneck identified in CAISO's 2024–2025 Economic Preliminary Assessment—and to provide additional interconnection capability for approximately 1.2 GW of new generation projected in the Southern California Edison (SCE) Northern Area. It supports improved resource deliverability, reliability, and economic performance through a strategic expansion of existing infrastructure, complementing CAISO's long-term system reinforcement plan.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-9.

Table G.8-9: Evaluating study request – Midway – Pastoria – Whirlwind 500 kV Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Alleviates congestion on Path 26, which showed $189M and $140M congestion costs in CAISO's 2034 and 2039 Base Portfolio simulations.	This project helps to reduce congestion on the Path 26 corridor
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Creates new interconnection opportunity for 1.2 GW of generation in the SCE Northern Area.	Supports integration of renewables in PG&E Kern area and SCE Northern area
Local Capacity Area Resource requirements	Enhances Resource Adequacy and reduces strain on northern SCE substations.	Not identified
Increase in Identified Congestion	No increase expected; new lines and substation mitigate existing Path 26 constraints.	Not identified
Integrate New Generation Resources or Loads	Facilitates renewable resource delivery to load centers in southern California.	Supports integration of renewables in PG&E Kern area and SCE Northern area
Other	Improves reliability and resilience; estimated $342M net system savings over 50 years.	Not identified

Conclusion

Path 26 corridor congestion was selected to receive detailed economic assessment in this planning cycle with considering different alternatives, as set out in Section G.9.

G.8.10 Study request for Devers 500/230 kV Transformer Expansion and Path 15 Upgrade Project

Study request overview

SB Energy submitted the Devers 500/230 kV Transformer Expansion and Path 15 Upgrade Project for consideration in the 2025–2026 Transmission Planning Process (TPP). The study request proposes two major transmission enhancements:

1. Expansion of the Devers 500/230 kV Substation through the addition of a third 500/230 kV transformer bank to mitigate congestion and overloads under contingency conditions.
2. Reinforcement of the Path 15 corridor, including potential upgrades to the Los Banos–Gates–Midway 500 kV lines and reconductoring of Las Aguilas – Moss Landing 230 kV circuits.

The project addresses thermal overloads on the Devers transformers under multiple contingencies—such as the loss of existing transformer banks or critical 500 kV tie-lines (Serrano–Valley or N. Gila–Imperial Valley). SB Energy's proposal aligns with CAISO's reliability and economic objectives by enhancing transformer capacity, improving north–south power transfer capability, and alleviating congestion that restricts renewable energy delivery into major Southern California load centers.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-10.

Table G.8-10: Evaluating study request – Devers 500/230 kV Transformer Expansion and Path 15 Upgrade Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Mitigates transformer congestion at Devers 500/230 kV and reduces Path 15 bottlenecks.	Path 15 corridor upgrade and Las Aguilas – Moss Landing 230 kV reconductoring helps to reduce congestion in these areas. Devers 500/230 kV transformer only showed minor congestion.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Improves delivery of renewable generation from Imperial Valley and Central California.	Path 15 corridor upgrade and Las Aguilas – Moss Landing 230 kV reconductoring Supports integration of renewables in the PG&E Fresno and Kern areas
Local Capacity Area Resource requirements	Reduces dependence on local gas-fired generation in the LA Basin.	Not identified
Increase in Identified Congestion	No increase anticipated; project addresses existing transformer and path constraints.	Not identified
Integrate New Generation Resources or Loads	Supports interconnection and delivery of renewable projects in Imperial Valley and Central California.	Path 15 corridor upgrade and Las Aguilas – Moss Landing 230 kV reconductoring Supports integration of renewables in the PG&E Fresno and Kern areas
Other	Enhances contingency performance and reduces outage-related curtailments.	Not identified

Conclusion

Path 15 corridor congestion and Las Aguilas – Moss Landing 230 kV congestion were selected to receive detailed economic assessment in this planning cycles with considering different alternatives, as set out in Section G.9. Devers 500/230 kV transformer upgrade was not selected for detailed production cost simulation in this planning cycle.

G.9 Detailed Investigation of Congestion and Economic Benefit Assessment

G.9.1 Selection of Detailed Studies

The ISO selected the high priority study areas, listed in Table G.9-1, for further detailed assessments. In this planning cycle, the 2040 base portfolio PCM case was used as the main case for the detailed economic assessment. The selection was based on the detailed production cost simulation results as set out in section G.7, with taking into account the economic study requests as evaluated in section G.8.

Table G.9-1: Areas receiving detailed economic assessment

Detailed investigation	Alternative	Reason for receiving detailed assessment
Path 26 corridor and Western LA Basin	10 alternatives were studied as set out in section G.9.2	Path 26 congestion is recurring congestion with large congestion cost. La Fresa – La Cienega 230 kV congestion was also observed. The mitigation alternatives are expected to help to mitigate the congestion, and to reduce local capacity requirements.
Path 15 corridor	19 alternatives were studied as set out in section G.9.3	Path 15 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles, as the resource assumption changed in the CPUC IRP portfolio.
Las Aguilas-Moss Landing	One alternative were studied as set out in section G.9.4	As the portfolio resource capacity increase in the PG&E's Fresno and Kern areas and the load increase in the south Bay area, the Las Aguilas – Moss Landing 230 kV line congestion increased.

G.9.2 Path 26 Corridor and Western LA Basin

Congestion analysis

The most significant congestion on the Path 26 corridor was the Path 26 path rating binding when the flow was from south to north. The Midway – Whirlwind 500 kV line congestion under both Midway – Vincent 500 kV lines N-2 or normal conditions were observed when the flow was from south to north as well. Renewable generators in the Southern California area in the CPUC IRP portfolio were the main drivers of the Path 26 corridor congestion in the south to north direction, which is consistent with the results in the previous planning cycles.

Congestion on the Path 26 corridor when the flow was from north to south was also observed, attributed to the increase of renewable generation in the PG&E area in the CPUC portfolio, including offshore wind generation. Midway to Vincent 500 kV line was congested under Midway – Vincent 500 kV N-1 contingency. This congestion became worse in this planning cycle than in the previous planning cycle because the 4-hour emergency rating, instead of the 30-minute rating, was used in this TPP cycle's PCM case, which reflected the CAISO and SCE's operating procedure change in 2025. The congestion cost and hours of the Path 26 corridor congestion are shown in Table G.9-2.

Table G.9-2: Major Path 26 corridor congestions in the 2040 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
P26 Northern-Southern California	24	11	218,866	2,382	218,890	2,393
MW_VINCNT_22-VINCENT 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	79,016	1,124	104	24	79,120	1,148
MIDWAY-MW_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	12,857	204	12,857	204
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	0	0	8,960	168	8,960	168
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	7,863	614	7,863	614
MW_VINCNT_22-VINCENT 500 kV line #2	1,176	18	0	0	1,176	18
MW_WRLWND_32-WIRLWIND 500 kV line #3	0	0	8	10	8	10
MIDWAY-MW_WRLWND_31 500 kV line #3	0	0	2	2	2	2

Western LA Basin congestion increased in this planning cycle. The cancelation of the Del Amo upgrade project and the increase of data center load and battery storage in the Western LA Basin area were the main drivers for the Western LA Basin congestion increase. The congestion cost and hours of the LA Basin congestion are shown in Table G.9-3.

Table G.9-3: Major Western LA Basin congestions in the 2040 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	132,298	2,785	132,298	2,785
BARRE-LEWIS 230 kV line #1	0	0	11,058	938	11,058	938
LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	0	0	4,756	315	4,756	315
LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	281	151	281	151
MESACALS-LAGUBELL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV and Mesa-La Fresa 230 kV	134	98	0	0	134	98
MESACALS-LAGUBELL 230 kV line #2	17	114	0	0	17	114
HINSON-DELAMO 230 kV line, subject to SCE N-2 La Fresa-Laguna Bell 230 kV #1 and La Fresa-Mesa 230 kV #1	0	0	2	18	2	18
LAGUBELL-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #2 and Mesa-Lighthipe 230 kV	0	0	2	6	2	6

Congestion mitigation alternatives

Ten alternatives for mitigating Path 26 corridor and Western LA Basin area congestion were assessed:

- Alternative 1: Bypass series capacitor on the Midway – Whirlwind 500 kV line.
- Alternative 2: Eliminate the Midway – Vincent N-2 contingency in the PCM by considering it as conditional P7 or expanding the RAS for Path 26. With eliminating the Midway – Vincent N-2, the Path 26 path rating is assumed to be 5000 MW north to south and 4400 MW south to north according the WECC Path rating study.
- Alternative 3: Alternative 2 plus restoring to use 30-minute emergency rating for the Midway – Vincent 500 kV lines under Midway – Vincent N-1.
- Alternative 4: Combination of Alternative 1 and Alternative 3, i.e. eliminating Midway – Vincent N-2, using 30-minute rating for Midway – Vincent lines, and bypassing the series compensation on the Midway – Whirlwind 500 kV line.
- Alternative 5: Reconductoring the Midway – Vincent #1 and #2 500 kV lines and the Midway – Whirlwind 500 kV line to be able to carry 4000 Amps flow. The Path 26 path rating was assumed to increase by 800 MW based on preliminary assessment with the reconductoring.
- Alternative 6: Build a new Midway – Windhub 500 kV line, which not only provides a parallel line to the existing Midway – Whirlwind 500 kV line, but also helps to relief generation deliverability issue at the Windhub 500 kV substation.
- Alternative 7: PTEP project - a 2000 MW offshore HVDC line from Diablo Canyon to El Segundo, and four 230 kV underground HVAC cables from El Segundo to El Nido and Redondo, respectively.
- Alternative 8: K-SEL project - a 2000 MW HVDC line from Midway to El Nido.
- Alternative 9: Alternative 7 (PTEP) plus Alternative 4.
- Alternative 10: Alternative 8 (K-SEL) plus Alternative 4.

Congestion mitigation

Table G.9-4 shows the congestion cost in Path 26 corridor and LA Basin area in the base case and the PCM case with transmission upgrade alternative modeled.

Table G.9-4: Impact of transmission alterantives on congestion costs in Path 26 corridor and Western LA Basin area

	Congestion Cost ($M/year)								
Case	Path26	Midway-Whirlwind Normal	Midway-Whirlwind N2	Midway-Vincent_ #1 N1	Midway-Vincent_ #2 N1	MesaCals-LaguBell_ #1 N2	LaFresa-Lacienega N2	LaFresa -Hinson N2	ELNido-Lacienega N2
Base case	218.9	7.9	12.9	0.0	79.1	4.8	132.3	0.0	0.0
A1 (Bypass s. cap)	84.8	0.0	0.7	0.0	260.8	4.7	131.7	0.0	0.0
A2 (Remove N-2)	0.4	10.9	0.0	0.0	145.6	4.6	132.2	0.0	0.0
A3 (A2 + 30 min. rating)	2.3	11.0	0.0	0.0	3.6	7.8	132.2	0.0	0.0
A4 (A1 + A3)	0.4	0.0	0.0	0.0	27.6	7.4	131.1	0.0	0.0
A5 (Reconductoring)	59.5	0.0	5.1	0.0	0.0	9.3	132.2	0.0	0.0
A6 (New Midway-Windhub line)	41.1	0.0	0.0	0.0	94.7	4.0	132.8	0.0	0.0
A7 (PTEP)	91.7	5.5	8.5	0.0	30.7	0.0	0.0	42.8	0.0
A8 (K-SEL)	163.2	9.1	12.6	0.0	48.3	0.2	26.6	0.0	28.9
A9 (A4 + A7)	0.1	0.0	0.0	0.0	6.7	0.0	0.0	17.4	0.0
A10 (A4 + A8)	1.0	0.0	0.0	0.0	25.3	0.3	0.7	0.0	32.7

It was observed that Alternative 1 bypassing series compensation of the Midway – Whirlwind line can mitigate congestion of the Midway – Whirlwind line, but it aggravated congestion on the Midway – Vincent line. Alternative 2, eliminating the Midway – Vincent N-2 contingency and the path rating increase, can effectively mitigate congestion caused by Path 26 path rating binding, but the Midway – Vincent congestion was aggravated as the flow through the Path 26 corridor increased. Alternative 3, which is the combination of Alternative 2 and adopting 30-minute rating of the Midway – Vincent line, can effectively mitigate both Path 26 and Midway – Vincent congestions. Alternative 4 that further combined Alternative 3 and Alternative 1 can mitigate the Path 26 congestion and the Midway – Whirlwind congestion. Even though the Midway – Vincent congestion still showed up in the Alternative 4 case, the congestion cost significantly reduced.

Alternative 5, reconductoring the Midway – Vincent #1 and #2 and Midway – Whirlwind #3 lines, can mitigate most of congestions on the individual lines of the Path 26 corridor but there was still congestion due to Path 26 path rating binding and the Midway – Whirlwind congestion under the Midway – Vincent N-2 contingency. Alternative 6, building a new 500 kV AC line between Midway and Windhub, was effective to mitigate congestion on the Midway – Whirlwind 500 kV line but the Path 26 congestion and Midway – Vincent congestion under N-1 contingency was still observed.

HVDC line alternatives, Alternative 7 (PTEP) and Alternative 8 (K-SEL), were not as effective to mitigate Path 26 corridor congestion, compared to other alternatives. It was also observed that even though these two alternatives can help to mitigate the existing LA Basin congestions, such as La Fresa – La Cienega and Mesa Cal – Laguna Bell congestions, they caused new congestions in the Western LA Basin area, such as the La Fresa – Hinson and El Nido – La Cienega 230 kV line congestion.

Alternatives 9 and 10 are the combination of Alternative 4 with the PTEP project and the K-SEL project, respectively. These two alternatives did not show significant incremental benefit for mitigating congestion compared to the Alternative 4 results.

Production cost and ISO payment results

Table G.9-5 shows the ISO's load payment, generator profile, and transmission revenue from production cost simulations for the Path 26 and LA Basin congestion mitigation alternatives.

Three approaches were used to calculate congestion revenue for ISO's ratepayers, as discussed in Section G.2.4:

- S0: The current TEAM approach, i.e. allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's ownership of transmission lines and paths.
- S1: Allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.
- S2: Allocate congestion revenue of entire WECC's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

Table G.9-5: Production cost simulation results for Path 26 and LA Basin congestion mitigation alternatives

			ISO Trans Revenue ($M/year)			ISO Net Payment ($M/year)			
Case	ISO Load Payment ($M/year)	ISO Gen Profit ($M/year)	S0- Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	S0 - Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	WECC Production Cost ($M/year)
Base case	20,718	11,388	3,845	2,629	2,922	5,485	6,700	6,408	28,087
A1 (Bypass s. cap)	20,836	11,507	3,799	2,590	2,887	5,529	6,738	6,442	28,093
A2 (Remove N-2)	20,669	11,346	3,864	2,644	2,937	5,459	6,679	6,386	28,061
A3 (A2 + 30 min. rating)	20,652	11,292	3,938	2,721	3,011	5,423	6,639	6,349	28,040
A4 (A1 + A3)	20,612	11,292	3,894	2,686	2,977	5,426	6,634	6,343	28,033
A5 (Reconductoring)	20,635	11,279	3,940	2,724	3,014	5,416	6,632	6,342	28,035
A6 (New Midway-Windhub line)	20,686	11,326	3,896	2,669	2,959	5,464	6,691	6,401	28,062
A7 (PTEP)	20,051	11,319	3,283	2,252	2,546	5,449	6,479	6,185	27,942
A8 (K-SEL)	20,308	11,364	3,533	2,412	2,705	5,410	6,531	6,238	28,013
A9 (A4 + A7)	20,003	11,314	3,256	2,233	2,528	5,432	6,456	6,161	27,920
A10 (A4 + A8)	20,241	11,312	3,536	2,420	2,717	5,394	6,510	6,213	27,979

Cost estimates

Alternatives 1, 2, 3, and 4 either have zero cost or only have small cost for equipment replacement or operating procedure modification. The actual cost of these alternatives is subjective to further assessment. Small lump-sum costs were assumed for these alternatives for benefit to cost ratio calculation. The capital costs of reconductoring 500 kV lines (Alternative 5), building a new 500 kV line (Alternative 6), and the K-SEL HVDC project (Alternative 8), were estimated based on the ISO's per unit cost. The capital cost in the PTEP economic study request was used for the PTEP project economic assessment. The ISO's screening factor of 1.3 then was applied to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost".

It is worth noting that the cost estimates for the Path 26 corridor upgrades studied in this planning cycle did not include the cost for potential substation upgrades, which may be significant if major substation expansion or new substation was triggered.

Production cost savings and benefit to cost ratio

The production cost savings were the base case's ISO net payment minus the alternative case's ISO net payment for Alternatives 1~8.

The production cost savings of Alternative 9 (the PTEP project plus Alternative 4) and Alternative 10 (the K-SEL project plus Alternative 4) were calculated using Alternative 4 as the base in order to assess the impact of Path 26 congestion mitigation on these two projects.

The present value of production cost saving is used to calculate benefit to cost ratio. To calculate the present value, 7% real discount rate was used, and 40-year economic life was assumed for Alternatives 1~5, and 50-year for Alternatives 6~10.

The production cost savings, estimated total cost, and the benefit to cost ratios of the mitigation alternatives for the Path 26 and LA Basin area were shown in Table G.9-6.

Table G.9-6: Production Benefits, cost and BCR of Path 26 corridor and LA Basin area congestion mitigation alternatives

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	WECC Saving		S0 - Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue
A1 (Bypass s. cap)	-44	-38	-34	-6	1	(592.73)	(508.14)	(450.22)
A2 (Remove N-2)	26	21	22	26	39	8.74	7.29	7.36
A3 (A2 + 30 min. rating)	62	61	59	48	39	21.26	20.73	20.11
A4 (A1 + A3)	59	66	65	55	40	19.80	22.05	21.75

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	WECC Saving		S0 - Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue
A5 (Reconductoring)	69	68	66	52	2,442	0.38	0.37	0.36
A6 (New Midway-Windhub line)	21	9	7	25	948	0.31	0.13	0.10
A7 (PTEP)	36	221	223	145	2,860	0.17	1.06	1.07
A8 (K-SEL)	75	169	170	75	2,787	0.37	0.84	0.84
A9 (A4 + A7)	-7	178	182	113	2,860	(0.03)	0.86	0.88
A10 (A4 + A8)	32	124	130	54	2,787	0.16	0.62	0.64

Three zero-cost or low-cost alternatives, Alternatives 2, 3, and 4, showed significant benefit to ISO's ratepayers compared to their cost, no matter which congestion cost allocation approach was used. Bypassing series capacitor of the Midway – Whirlwind line (Alternative 1) alone showed negative benefit. Alternative 5 and Alternative 6, reconductoring the three 500 kV lines and building a new Midway – Windhub line, respectively, showed positive benefit to ISO's ratepayers but their benefit to cost ratios were less than 1.0.

The HVDC alternatives (Alternative 7 and Alternative 8) did not have sufficient benefit to ISO's ratepayer based on the current TEAM congestion revenue allocation approach. Alternative 7 (the PTEP project) showed BCR greater than 1.0 when the new congestion revenue allocation approaches (S1 and S2) were used, but as shown in the results of Alternatives 9 the PTEP project benefit reduced below 1.0 if Path 26 corridor congestion was mitigated by the zero-cost or low- cost upgrades (Alternative 4). The same trend was observed for the K-SEL project.

LCR reduction benefit

The PTE project, which is to build a HVDC line from Diablo Canyon to El Segundo, can potentially reduce LCR requirement in the LA Basin area. The K-SEL project, which is to build a HVDC line from Midway to El Nido, is similar the PTE project in term of reducing LCR requirement in the LA Basin area. According to the previous TPP, the LCR requirement reduction for the LA Basin area by the PTE project was approximately equal to the capacity of the HVDC line coming into the Western LA Basin. In the meantime, the capacity requirements reduced in the local area will still be needed for system RA. Using the same assumption in this planning cycle, LCR reduction for the LA Basin area by the PTE or K-SEL projects is assumed to be approximately equal to the transmission capacity of the projects. According to the economic study request overview in section 8, each of these two projects can provide about 2000 MW additional transmission capacity to the Western LA Basin.

It is worth noting that the assumptions for LCR reduction in this study were used only for screening purposes. Detailed LCR study will be needed if the screening results show that a project may provide economic benefit to CAISO's ratepayers sufficient or close to compensate the cost of the project.

In this planning cycle, the capacity costs in the latest CPUC 2023 Resource Adequacy Report[8] were used to calculate the LCR reduction savings. The capacity costs for the southern California areas and the system capacity costs in the CPUC report were summarized in Table G.9-7. The costs then were converted to 2024 dollar[9].

Table G.9-7: Capacity cost in CPUC Resource Adequacy Report

Area	Weighted average capacity cost ($/kW-month) in CPUC 2023 RA report	In 2024 dollar
System	11.11	11.79
SP26	10.89	11.55
LA Basin	11	11.67

The LCR reduction benefit results assessed based on CPUC's capacity cost were summarized in Table G.9-8.

Table G.9-8: LCR reduction savings based on the capacity costs in the CPUC 2022 Resource Adequacy Report

	PTE		K-SEL	
	Local vs System RA cost	Local vs SP 26 RA cost	Local vs System RA cost	Local vs SP 26 RA cost
LCR reduction benefit (Western LA Basin) (MW)	2,000		2000	
Capacity value($/MW-year)	-1,400	1,400	-1,400	1,400
LCR Reduction Benefit ($million/year)	-2.80	2.80	-2.80	2.80

The system RA capacity cost is greater than the LA Basin local RA capacity cost, but the SP 26 RA capacity cost is less than the LA Basin local RA capacity cost. Therefore, only using the SP26 RA contract to replace the LA Basin local RA contract can potentially bring incremental capacity benefit for the PTEP and K-SEL projects. The benefit to cost ratios of these two projects were updated based on this assumption, as shown in Table G.9-9. Compared with Table G.9-6, the benefit to cost ratio results of the PTEP and K-SEL projects did not have directional change with considering the LCR benefit.

8 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf

9 https://efiling.energy.ca.gov/GetDocument.aspx?tn=254569&DocumentContentId=89994

Table G.9-9: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of PTE project and K-SEL project

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	WECC Saving		S0 - Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue
A7 plus LCR SP26	39	223	225	145	2,860	0.19	1.08	1.09
A8 plus LCR SP26	78	172	172	75	2,787	0.38	0.85	0.85
A9 plus LCR SP26	-4	181	185	113	2,860	(0.02)	0.87	0.89
A10 plus LCR SP26	35	127	133	54	2,787	0.17	0.63	0.66

Conclusion

Ten transmission upgrades were assessed in this section for mitigating Path 26 corridor and Western LA Basin area congestion, including four zero-cost or low-cost alternatives. Bypassing series capacitor of the Midway -Whirlwind 500 kV line alone did not have positive benefit for ISO's ratepayers. The other three zero-cost or low-cost alternatives showed positive benefit to the ISO's ratepayers and were effective to mitigate the Path 26 corridor congestion.

The alternatives of adding new wires, AC or DC, also showed positive benefits but the benefit to cost ratios were less than 1.0 based on the current TEAM congestion revenue allocation approach. The benefit to cost ratio of the PTEP project can be greater than 1.0 when the new congestion revenue allocation approaches were used but reduced below 1.0 if majority of Path 26 corridor congestion was mitigated in the first place, for example by modeling mitigations in Alternative 4. The PTEP and K-SEL projects may create new congestion in the Western LA Basin area while they helped to mitigate some existing congestion.

Based on the economic assessment results in this planning cycle, it was recommended to:

- Evaluate the Midway – Vincent 500 kV N-2 contingency to determine if it can be categorized as conditional P7, or if the current RAS for Path 26 can be
- Evaluate and restore the Midway – Vincent #1 and # 2 500 kV lines 30-minute emergency ratings under the Midway – Vincent 500 kV line N-1 contingency
- Consider bypassing the series capacitor of the Midway – Whirlwind 500 kV line when the Midway – Vincent 500 kV lines 30-minute ratings were restored
- Assess and identify any potential system modification associated with the above mitigations

It was noted that the Path 26 corridor may still have some congestion with the above recommended mitigations being modeled, even though not significant. The ISO will continue to monitor the Path 26 corridor and assess if incremental mitigation is needed.

The PTEP and K-SEL projects, as the congestion analysis results showed, can cause new congestion in the Western LA Basin area while some existing congestion was relieved. Further assessments of these projects may be needed in future planning cycles, with taking into account the potential LA Basin reliability upgrades.

G.9.3 Path 15 Corridor

Congestion analysis

Path 15 is defined as the electrical cut-plane south of Los Banos, encompassing the three 500 kV lines running south to Gates and Midway. Given the pivotal role this particular transmission plays, however, it is best to think of reinforcements addressing the congestion on the specific cut-plane in terms of reinforcements to the overall corridor encompassing Path 15 in the San Joaquin valley, with solutions being considered that extend north to Tesla, and south to Midway and Whirlwind.

The majority of the Path 15 corridor congestion was observed on the south of Manning 500 kV lines, including the Gates – Manning, Midway – Gates, and Midway – Manning 500 kV lines. The Path 15 corridor congestion occurred when the flow was from south to north. The Gates – Panoche 230 kV line and the Fink Switching Station to Westley 230 kV line congest was also observed. The Path 15 corridor congestion showed significant increase in this planning cycle due to the resource assumption changed in the Fresno/Kern area in the CPUC IRP portfolios for this TPP cycle. Path 26 flow from south to north and the Diablo Canyon offshore wind generation also contributed to the Path 15 corridor congestion. The Path 15 corridor congestions were summarized in Table G.9-10.

Table G.9-10: PG&E Path 15 corridor congestions in the 2040 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MANNING-MN_GT_11 500 kV line #1	0	0	885,359	3,866	885,359	3,866
MANNING-MN_GT_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	536,317	2,921	536,317	2,921
GATES-GT_MW_11 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	107,896	679	107,896	679
MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	93,224	545	93,224	545
MN_GT_11-GATES 500 kV line #1	0	0	59,820	287	59,820	287
MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Midway-Gates 500 kV	0	0	43,520	406	43,520	406
GT_MW_11-MIDWAY 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV South Gates	0	0	31,186	493	31,186	493
MN_MW_23-MIDWAY 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	21,129	448	21,129	448
MANNING-MN_MW_21 500 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	14,144	303	14,144	303
GT_MW_11-MIDWAY 500 kV line #1	0	0	11,705	56	11,705	56
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Manning-Gates 500kV #1 with SPS	0	0	5,479	158	5,479	158

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
GATES-GT_MW_11 500 kV line #1	0	0	2,389	56	2,389	56
MN_MW_23-MIDWAY 500 kV line #2	0	0	1,988	7	1,988	7
FINKSWSTA-WESTLEY 230 kV line #1	1,176	50	0	0	1,176	50
MN_GT_11-GATES 500 kV line, subject to PG&E N-1 Midway-Manning 500 kV North Gates	0	0	1,093	7	1,093	7
MANNING-MN_MW_21 500 kV line #2	0	0	918	4	918	4
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	725	56	725	56
MN_MW_22-MN_MW_23 500 kV line #2	0	0	21	1	21	1
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	10	1	10	1
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	10	1	10	1

Congestion mitigation alternatives

Nineteen transmission alternatives for mitigating Path 15 corridor congestion were assessed in this planning cycle. Some alternatives include upgrades for the Path 26 corridor since the Path 26 and Path 15 flows are highly correlated with each other. All proposed new 500 kV lines were modeled with 70% series compensation in PCM studies.

- Alternative 1: Add 70% series compensation on the Gates – Los Banos #3 500 kV line. This alternative is to balance the impedances between all three 500 kV lines between the Gates and Los Banos substations.
- Alternative 2: Alternative 1 plus loop the Gates – Los Banos #3 line in the Manning substation and loop the Midway – Manning #2 line in the Gates substation.
- Alternative 3: Alternative 1 plus reconductoring the Gates – Los Banso #3 line, the Midway – Gates #1 and Gates – Manning #1 line, and the Midway – Manning #2 line. The ratings of the reconductored lines are 3464/3880 MVA and 3291/3817 MVA for the conductor and series compensation, respectively.
- Alternative 4: Alternative 1 plus adding a new Midway – Tesla 500 kV line using a different corridor.
- Alternative 5: Alternative 4 plus adding a new Windhub – Midway 500 kV line
- Alternative 6: Alternative 5 plus tying the new Midway – Tesla 500 kV line to the Gates substation.
- Alternative 7: Alternative 2 plus reconductoring the Gates – Los Banso #3 line, the Midway – Gates #1 and Gates – Manning #1 line, and the Midway – Manning #2 line. The ratings of the reconductored lines are 3464/3880 MVA and 3291/3817 MVA for the conductor and series compensation, respectively.
- Alternative 8: Alternative 2 plus adding a new Midway – Tesla 500 kV line

- Alternative 9: Alternative 8 plus adding a new Windhub – Midway 500 kV line
- Alternative 10: Alternative 3 plus adding a new Midway – Tesla 500 kV line
- Alternative 11: Alternative 10 plus adding a new Windhub – Midway 500 kV line
- Alternative 12: Alternative 1 plus reconductoring the Gates – Los Banos # 3 line
- Alternative 13: Alternative 12 plus adding a new Midway – Tesla 500 kV line
- Alternative 14: Alternative 13 plus adding a new Windhub – Midway 500 kV line
- Alternative 15: Alternative 14 plus the new Midway – Tesla line ties to Gates
- Alternative 16: Alternative 3 plus adding a new Manning – Tesla 500 kV line
- Alternative 17: Alternative 7 plus adding a new Manning – Tesla 500 kV line
- Alternative 18: Alternative 12 plus adding a new Midway – Gates 500 kV line
- Alternative 19: Alternative 18 plus adding a new tie line from the Manning substation to the existing Gates – Los Banos #3 500 kV line

Congestion mitigation

Table G.9-11 shows the congestion costs on Path 15 corridor, in the 2040 base portfolio PCM case and the PCM cases with mitigation alternative modeled.

Table G.9-11: Impact of transmission alternatives on Path 15 corridor congestion

	Congestion Cost ($M/year)							
Case	MN-GT Normal	MN-GT N1	MW-GT Normal	MW-GT #1 N1	MW-GT #2 N1	MW-MN Normal	MW-MN N1	GT-LB N1
Base case	945.2	537.4	14.1	139.1	0.0	2.9	172.0	0.0
A1 (Gates - Los Banos #3 70pst comp.)	0.0	0.0	89.7	367.7	0.0	1.1	215.6	740.7
A2 (A1 plus existing 500 kV lines loop in Manning and Gates)	0.4	309.1	0.0	7.8	1,411.7	0.0	0.0	0.0
A3 (A1 plus reconductor Gates – Los Basno #3 and south of Manning 500 kV lines)	0.0	45.7	8.0	237.8	0.0	0.0	0.0	0.0
A4 (A1 plus new Midway-Tesla 500 kV line)	0.0	0.0	60.0	0.3	0.0	2.3	2.5	414.5
A5 (A4 plus new Windhub-Midway 500 kV line)	0.0	0.0	181.2	27.6	0.0	4.0	4.3	406.5
A6 (A5 plus the new line ties to Gates)	0.0	0.0	123.7	0.0	0.0	23.5	0.0	294.2
A7 (A2 plus reconductor Gates – LosBanos #3 and south of Manning 500 kV lines)	0.0	0.0	0.0	0.0	281.0	0.0	0.0	0.0
A8 (A2 pus plus new Midway – Tesla)	0.2	104.8	0.0	0.0	624.6	0.0	0.0	0.0
A9 (A8 plus new Windhub – Midway)	0.0	87.7	0.0	0.0	894.2	0.0	0.0	0.0
A10 (A3, plus new Midway – Tesla)	0.0	3.3	0.0	0.1	0.0	0.0	0.0	0.0
A11 (A10 plus new Windhub - Midway)	0.0	1.9	1.7	16.9	0.0	0.0	0.0	0.0
A12 (A1 plus reconductoring Gates – Los Banos #3 500 kV line)	260.8	46.3	77.3	449.2	0.0	46.1	200.1	0.0
A13 (A12 plus new Midway – Tesla)	136.6	9.7	58.4	1.2	0.0	26.2	5.3	0.0
A14 (A13 plus new Windhub – Midway)	118.1	4.2	146.3	38.8	0.0	47.8	34.3	0.0
A15 (A14 plus the new line ties to Gates)	25.0	0.6	135.0	0.0	0.0	88.8	0.0	0.0
A16 (A3 plus new Manning – Tesla 500 kV line)	0.0	150.8	7.3	261.7	0.0	0.0	0.0	0.0
A17 (A7 plus new Manning – Tesla 500 kV line)	0.0	1.5	0.0	0.0	362.6	0.0	0.0	0.0
A18 (A12 plus new Midway -Gates 500 kV line)	623.0	169.8	0.0	0.2	0.0	0.2	0.0	0.0
A19 (A18 plus the Gates – Los Banos #3 ties in Manning)	386.9	331.9	0.0	1.2	0.0	0.1	0.0	0.0

Congestion on the Las Aguilas – Moss Landing 230 kV and Manning – Metcalf 500 kV lines was observed in the 2040 base portfolio PCM case and was aggravated in some alternative cases in the Path 15 corridor study. Table G.9-12 shows the congestion costs on Las Aguilas – Moss Landing 230 kV and Manning – Metcalf 500 kV lines, in the base portfolio PCM case and the PCM cases with Path 15 corridor mitigation alternatives modeled.

Table G.9-12: Impact of transmission alternatives on Las Aguilas – Moss Landing and Manning - Metcalf corridor congestion

	Congestion Cost ($M/year)			
Case	Las Aguilas -Moss Landin Normal	Las Aguilas - Moss Landin N1	Manning - Metcalf Normal	Manning - Metcalf N1
Base case	39.5	28.5	8.1	3.8
A1 (Gates - Los Banos #3 70pst comp.)	43.5	40.7	6.9	15.3
A2 (A1 plus existing 500 kV lines loop in Manning and Gates)	55.3	78.0	114.8	48.7
A3 (A1 plus reconductor Gates – Los Basno #3 and south of Manning 500 kV lines)	51.3	45.5	113.8	194.8
A4 (A1 plus new Midway-Tesla 500 kV line)	72.5	0.6	6.0	4.7
A5 (A4 plus new Windhub-Midway 500 kV line)	68.4	0.2	2.1	1.9
A6 (A5 plus the new line ties to Gates)	79.0	0.8	0.7	4.4
A7 (A2 plus reconductor Gates – LosBanos #3 and south of Manning 500 kV lines)	49.9	43.0	334.7	102.2
A8 (A2 pus plus new Midway – Tesla)	94.7	0.1	86.3	15.8
A9 (A8 plus new Windhub – Midway)	93.4	0.3	64.0	30.2
A10 (A3, plus new Midway – Tesla)	105.8	2.0	42.4	36.3
A11 (A10 plus new Windhub - Midway)	93.0	0.6	16.5	50.5
A12 (A1 plus reconductoring Gates – Los Banos #3 500 kV line)	50.4	56.7	64.7	76.7
A13 (A12 plus new Midway – Tesla)	95.7	0.9	38.0	20.5
A14 (A13 plus new Windhub – Midway)	88.1	0.3	18.7	30.7
A15 (A14 plus the new line ties to Gates)	89.7	0.6	0.8	52.1
A16 (A3 plus new Manning – Tesla 500 kV line)	113.1	0.7	1.7	8.4
A17 (A7 plus new Manning – Tesla 500 kV line)	123.8	1.6	44.3	10.7
A18 (A12 plus new Midway -Gates 500 kV line)	54.3	52.6	31.5	42.3
A19 (A18 plus the Gates – Los Banos #3 ties in Manning)	56.9	44.5	40.6	58.7

It was observed from Table G.9-11 and Table G.9-12 that most of the studied alternatives can help to reduce the overall congestion along the Path 15 corridor but congestion on some individual segments may be aggravated when the initial bottleneck was relieved. Congestion on the Las Aguilas – Moss Landing 230 kV line and Manning – Metcalf 500 kV line in general was also aggravated when the congestion along the Path 15 corridor congestion reduced. The major takeaways from the congestion mitigation results were summarized below:

- Adding series compensation on the Gates – Los Banos #3 line helped to balance flow among the three 500 kV lines of the Path 15. The existing congestion reduced but the Gates – Los Banos #3 line congestion increased after adding compensation.

- Looping the existing 500 kV lines in Manning and Gates without any other upgrade did not help to mitigate the overall Path 15 corridor congestion. Congestion was reduced on some segments but aggravated on other segments along the corridor.
- Only reconductoring the Gates – Los Banos #3 500 kV line aggravated congestion on the Midway – Gates line, and the congestion on the Gates – Manning line was reduced but still significant.
- Reconductoring the Gates – Los Banos #3 line and both 500 kV lines between the Manning and Midway substations helped to mitigate congestion under normal condition, but not under contingency conditions.
- Only upgrade the south of Manning segments of the Path 15 corridor, adding new line or reconductoring, can significantly increase congestion on the Las Aguilas – Moss Landing 230 kV line and the Manning – Metcalf 500 kV line. Only upgrade the south of Gates lines aggravated the congestion on the Gates – Manning line.
- Building a new line from Midway to Tesla helped to partially mitigate the Path 15 corridor congestion. Tying the new line in the Gates substation helped to further reduce the overall Path 15 corridor congestion, but not significantly.
- Extending the new line to add a new Windhub – Midway 500 kV segment, which can help to relief Path 26 congestion as shown in the Path 26 study but aggravated the Path 15 corridor congestion.
- Building a new line from Midway to Tesla plus reconductoring all three lines (the Gates – Los Banos line and the two lines south of Manning) helped to mitigate most of the congestion along the Path 15 corridor, and also help to reduce congestion on the Las Aguilas – Moss Landing 230 kV line and Manning – Metcalf 500 kV line, especially under contingency conditions.

Production cost and ISO payment results

Table G.9-13 shows the ISO's load payment, generator profile, and transmission revenue from production cost simulations for the Path 15 corridor congestion mitigation alternatives. The production cost savings were the base case's ISO net payment calculated minus the alternative case's ISO net payment for alternative cases.

Three approaches were used to calculate congestion revenue for ISO's ratepayers, as discussed in Section G.2.4:

- S0: The current TEAM approach, i.e. allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's ownership of transmission lines and paths.
- S1: Allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

- S2: Allocate congestion revenue of entire WECC's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

Table G.9-13: Production cost simulation results for Path 15 corridor congestion mitigation alternatives

Case	ISO Load Payment ($M/year)	ISO Gen Profit ($M/year)	ISO Trans Revenue ($M/year)			ISO Net Payment ($M/year)			WECC Production Cost ($M/year)
			S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	S0 - Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	
Base case	20,718	11,388	3,845	2,629	2,922	5,485	6,700	6,408	28,087
A1 (Gates - Los Banos #3 70pst comp.)	20,121	11,207	3,453	2,388	2,667	5,461	6,526	6,247	27,977
A2 (A1 plus existing 500 kV lines loop in Manning and Gates)	21,328	11,862	3,793	2,571	2,873	5,673	6,895	6,593	28,097
A3 (A1 plus reconductor Gates – Los Basno #3 and south of Manning 500 kV lines)	19,095	10,853	2,860	2,118	2,391	5,382	6,124	5,851	27,820
A4 (A1 plus new Midway-Tesla 500 kV line)	19,518	11,362	2,725	1,998	2,262	5,432	6,159	5,895	27,768
A5 (A4 plus new Windhub-Midway 500 kV line)	18,501	10,765	2,434	1,869	2,121	5,302	5,867	5,615	27,631
A6 (A5 plus the new line ties to Gates)	18,213	10,697	2,246	1,757	2,009	5,269	5,758	5,507	27,593
A7 (A2 plus reconductor Gates – LosBanos #3 and south of Manning 500 kV lines)	19,106	10,807	2,925	2,161	2,435	5,374	6,138	5,865	27,833
A8 (A2 pus plus new Midway – Tesla)	19,614	11,366	2,805	2,044	2,312	5,443	6,204	5,935	27,794
A9 (A8 plus new Windhub – Midway)	19,155	11,086	2,714	2,010	2,267	5,354	6,058	5,801	27,725
A10 (A3, plus new Midway – Tesla)	19,491	11,571	2,437	1,836	2,113	5,483	6,084	5,807	27,710
A11 (A10 plus new Windhub - Midway)	18,073	10,756	1,991	1,623	1,881	5,326	5,695	5,437	27,549
A12 (A1 plus reconductoring Gates – Los Banos #3 500 kV line)	20,102	11,285	3,341	2,357	2,639	5,477	6,461	6,179	27,925
A13 (A12 plus new Midway – Tesla)	19,452	11,450	2,561	1,919	2,188	5,442	6,083	5,814	27,741
A14 (A13 plus new Windhub – Midway)	18,402	10,834	2,264	1,782	2,038	5,304	5,787	5,530	27,599
A15 (A14 plus the new line ties to Gates)	18,189	10,786	2,111	1,684	1,939	5,291	5,718	5,463	27,572
A16 (A3 plus new Manning – Tesla 500 kV line)	19,227	11,214	2,600	1,923	2,202	5,412	6,089	5,810	27,750
A17 (A7 plus new Manning – Tesla 500 kV line)	19,138	11,159	2,562	1,904	2,182	5,416	6,075	5,796	27,759
A18 (A12 plus new Midway - Gates 500 kV line)	19,630	11,049	3,192	2,304	2,571	5,389	6,277	6,009	27,886
A19 (A18 plus the Gates – Los Banos #3 ties in Manning)	19,569	11,034	3,141	2,270	2,538	5,394	6,265	5,997	27,870

Cost estimates

As for the cost estimate, in general, the ISO per unit costs were used to estimate the capital cost of the transmission alternatives assessed for mitigating the Path 15 corridor congestion. The ISO's screening factor of 1.3 then was applied to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost".

It is worth noting that the cost estimates for the Path 15 corridor upgrades studied in this planning cycle did not include the cost for potential substation upgrades, which may be significant if major substation expansion or new substations were triggered.

Production savings and benefit to cost ratio

The production cost savings of Alternative 1 were the base case's ISO net payment minus the Alternative 1 case's ISO net payment. For the rest of alternatives, the production cost savings were calculated by using Alternative 1 as the base, since all these alternatives included the scope of Alternative 1. Correspondingly, the costs of these alternatives used in the benefit to cost ratio calculation did not include the cost of Alternative 1.

The present value of production cost saving is used to calculate benefit to cost ratio. To calculate the present value, a 7% real discount rate was used, and a 40-year economic life was assumed for reconductoring and 50 years for new lines.

The production cost savings, total cost, and the benefit to cost ratios of the mitigation alternatives for the Path 15 corridor were shown in Table G.9-14.

Table G.9-14: Production Benefits, cost and BCR of Path 15 corridor congestion mitigation alternatives

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	WECC Saving		S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue
A1 (Gates - Los Banos #3 70pst comp.)	24	174	161	111	195	1.66	11.91	11.02
A2 (A1 plus existing 500 kV lines loop in Manning and Gates)	-212	-369	-346	-120	298	(9.47)	(16.49)	(15.48)
A3 (A1 plus reconductor Gates – Los Basno #3 and south of Manning 500 kV lines)	79	402	396	157	1,752	0.60	3.06	3.01
A4 (A1 plus new Midway-Tesla 500 kV line)	29	367	352	209	2,028	0.20	2.50	2.39
A5 (A4 plus new Windhub-Midway 500 kV line)	159	659	632	345	2,976	0.74	3.06	2.93
A6 (A5 plus the new line ties to Gates)	191	768	740	383	3,271	0.81	3.24	3.12
A7 (A2 plus reconductor Gates – LosBanos #3 and south of Manning 500 kV lines)	87	388	382	143	2,050	0.56	2.52	2.49
A8 (A2 pus plus new Midway – Tesla)	18	322	312	182	2,327	0.11	1.91	1.85
A9 (A8 plus new Windhub – Midway)	107	468	446	251	3,274	0.45	1.97	1.88
A10 (A3, plus new Midway – Tesla)	-22	442	440	266	3,780	(0.09)	1.57	1.56
A11 (A10 plus new Windhub - Midway)	135	831	810	428	4,728	0.39	2.39	2.32

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue	WECC Saving		S0-Current Team	S1-Allocating ISO Congestion Revenue	S2-Allocating WECC Congestion Revenue
A12 (A1 plus reconductoring Gates – Los Banos #3 500 kV line)	-17	65	68	52	457	(0.48)	1.91	1.99
A13 (A12 plus new Midway – Tesla)	19	443	433	235	2,485	0.11	2.44	2.39
A14 (A13 plus new Windhub – Midway)	157	739	717	378	3,433	0.63	2.96	2.87
A15 (A14 plus the new line ties to Gates)	170	807	783	404	3,728	0.61	2.89	2.80
A16 (A3 plus new Manning – Tesla 500 kV line)	49	437	437	226	2,893	0.22	2.02	2.02
A17 (A7 plus new Manning – Tesla 500 kV line)	45	451	451	218	3,192	0.18	1.90	1.89
A18 (A12 plus new Midway -Gates 500 kV line)	72	249	238	91	1,330	0.75	2.56	2.44
A19 (A18 plus the Gates – Los Banos #3 ties in Manning)	67	261	250	106	1,424	0.66	2.51	2.40

Alternative 1 was the only alternative with benefit to cost ratio greater than 1.0 no matter which congestion revenue allocation approach was used. It was noted that the cost estimate for Alternative 1 assumed that a new switching station was needed for accommodating the series capacitors. Alternative 2, which is to loop the existing 500 kV lines in Manning and Gates, was the only alternative with negative benefit to ISO's ratepayers no matter which congestion cost allocation approaches were used. This is consistent with the congestion mitigation results that showed this alternative did not help to reduce the Path 15 corridor congestion.

Alternatives that are building new lines in parallel to the existing 500 kV lines along the Path 15 corridor or reconductoring the existing 500 kV lines had benefit to cost ratio greater than 1.0 when the new congestion revenue allocation approaches (S1 and S2) were used. Looping the new Midway – Tesla 500 kV line in the Gates substation or extending the new line to Windhub, or combining reconductoring and adding new line, can have higher benefit, but the benefit to cost ratios may not increase as the cost also increased.

Conclusions

Nineteen transmission alternatives for mitigating congestion on the Path 15 corridor were assessed in this section, some of which still resulted in significant congestion on the Path 15 corridor. Many alternatives studied can help to mitigate congestion of some segments of the Path 15 corridor but aggravate congestion of other segments. Congestion on downstream lines may be aggravated as well. Given the scope of issues discussed, it is necessary to consider shorter term and longer-term implications.

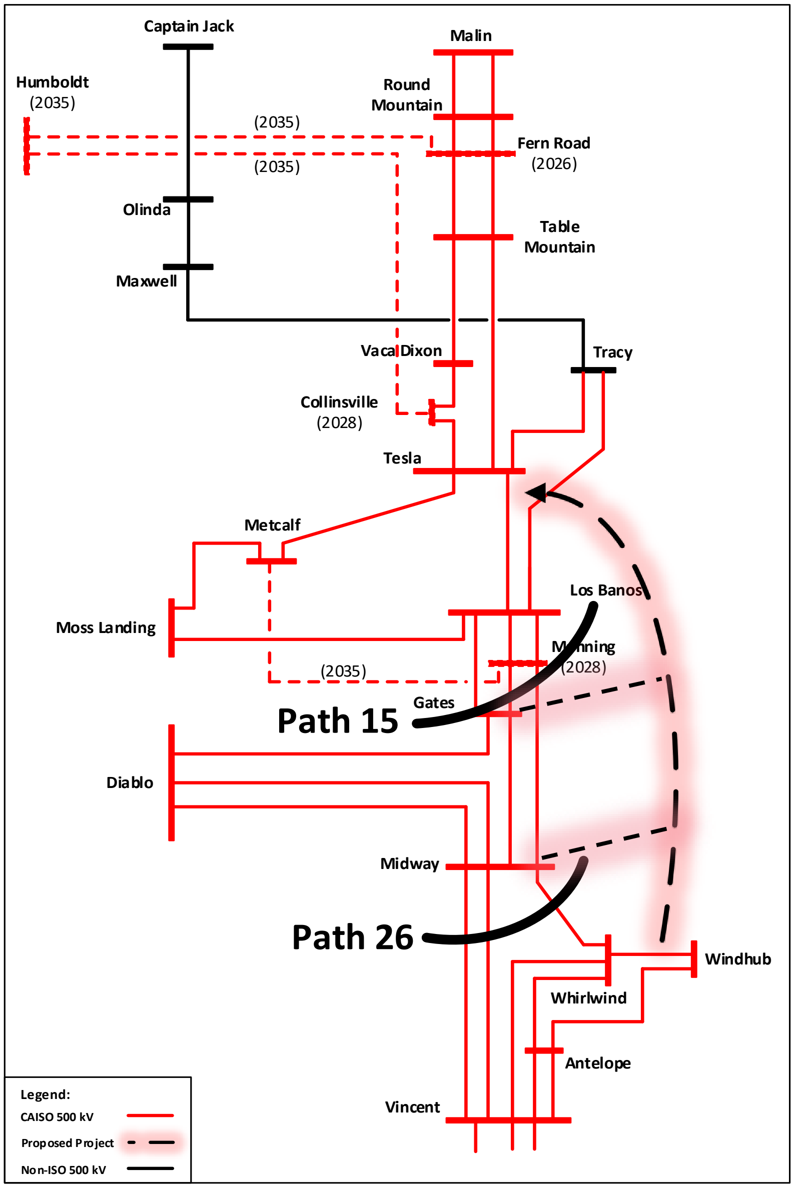
In the shorter term, adding 70% series compensation on the Gates – Los Banos #3 line, i.e. Alternative 1, helped to balance flow among the three 500 kV lines of the Path 15 corridor, even though congestion along the Path 15 corridor still existed. Among all transmission alternatives in this section, only Alternative 1 had benefit to cost ratio greater than 1.0 when the current and the revised congestion revenue allocation approaches were used.

Based on both of the congestion mitigation results and the production benefit results, Alternative 1 that is to add 70% series compensation on the Gates – Los Banos #3 500 kV line is recommended for approval as an economic-driven upgrade. With recognizing additional mitigations will be needed, Alternative 1 is a least-regret upgrade and its approval will provide some certainty for the already sophisticated Path 15 corridor assessment in the next planning cycle. In the longer term, all alternatives, except for Alternative 2, showed benefit to cost ratios greater than 1.0 when the new congestion revenue allocation approaches were used. These results demonstrate conclusively that Path 15 now requires substantial reinforcement to alleviate congestion on this corridor.

Alternative 6, which is Alternative 1 plus adding a new Windhub – Tesla 500 kV line tied into the Midway and Gates 500 kV substations, had the highest benefit to cost ratios among all alternatives other than Alternative 1 and was found to be the most economically favorable alternative in longer term. The ISO will consider recommending this alternative for approval in the next planning cycle after conducting bulk system reliability assessment by modeling this alternative to confirm if there is any impact on the bulk system. The scope of this alternative may require fine-tuning after the bulk system impact study.

Figure G.9-1 showed the 500 kV lines in northern California and Path 26. Path 15 and Path 26 were labeled on the diagram. The black dash line illustrated the transmission alternatives of adding a new Windhub – Tesla 500 kV line through a different right of way. Tying the new line to Midway and Gates that is a part of the scope of Alternative 6 was also shown in the diagram

Figure G.9-1: Diagram of Path 15 and Path 26



Other alternatives had lower benefit to cost ratios than Alternative 6, and most of them were not as effective in mitigating the Path 15 corridor and the downstream system congestion. Alternative 3, which is to reconductoring the Midway-Gates-Manning and Midway-Manning 500 kV lines and the Gates-Los Banos #3 500 kV line, had a benefit to cost ratio close to Alternative 6 but it significantly aggravated congestion on the Manning – Metcalf 500 kV line. Reconductoring all three lines may face some uncertainties. One of the uncertainties is that it may potentially trigger major substation upgrades, which may result in much higher total costs for the corresponding alternatives. Also, the total flow on the three reconductored 500 kV lines may be limited subject to path rating study to identify WECC wide system impact. The alternatives that are most effective to mitigate Path 15 corridor congestion are the Alternative 10 and Alternative 11, which are combinations of building a new line from Windhub or Midway to Tesla and reconductoring the Gates – Los Banos #3 line and the two 500 kV lines between the Midway and Manning substations. However, these alternatives have the same uncertainties as the alternatives doing reconductoring only.

While a longer term solution was identified, the ISO recognizes the need for comprehensive bulk system impact studies and detailed engineering studies for the Path 15 corridor and the upstream and downstream systems, including the Path 26 corridor and the Manning to Metcalf corridor. Such studies may include power flow and stability studies to identify new path ratings or transmission capacity, short circuit duty study to assess the need of substation expansion, and deliverability study to evaluate the impact on generation interconnection in the adjacent areas. Remedy action schemes (RAS) associated with the Path 26 and Path 15 corridors would be also revisited in the comprehensive study. With taking into account all of new study results, the scope of the longer term solution may need to be fine tuned. It is worth noting that additional upgrades may need to be considered beyond the identified longer term solution if Path 15 corridor congestion remains significant with the new load forecast and resource assumption in the next planning cycle.

G.9.4 Las Aguilas – Moss Landing 230 kV line

Congestion analysis

The congestion cost and hours of the Las Aguilas – Moss Landing 230 kV line are shown in Table G.9-15. The congestion cost and hours of the Manning – Metcalf 500 kV line, which is a parallel path to the Las Aguilas – Moss Landing 230 kV, are also shown in this table.

Table G.9-15: Las Aguilas – Moss Landing 230 kV and Manning – Metcalf 500 kV corridor congestion in the 2040 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MOSSLNSW-LASAGLSRCTR 230 kV line #1	0	0	39,457	1,219	39,457	1,219
MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Manning-Metcalf 500 kV with SPS	0	0	28,522	558	28,522	558
MANNING-MNMC_SC1 500 kV line #1	4,487	94	0	0	4,487	94
MNMC_SC2-METCALF 500 kV line #1	3,570	96	0	0	3,570	96
MANNING-MNMC_SC1 500 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV with SPS	1,609	97	0	0	1,609	97
MNMC_SC2-METCALF 500 kV line, subject to PG&E N-1 LosBanos-Tracy 500kV	855	7	0	0	855	7
MNMC_SC2-METCALF 500 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV with SPS	808	22	0	0	808	22
MANNING-MNMC_SC1 500 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV with SPS	493	6	0	0	493	6

Congestion mitigation alternatives

One alternative for mitigating Las Aguilas – Moss Landing 230 kV line congestion was assessed:

- Alternative 1: Reconductoring the Las Aguilas – Moss Landing 230 kV line.

Congestion mitigation

Table G.9-16 showed the congestion costs of the Las Aguilas – Moss Landing 230 kV line and Manning – Metcalf 500 kV lines in the base case and the alternative PCM case. This alternative was effective to mitigate the congestion of the 230 kV line, but slightly aggravated the Manning – Metcalf 500 kV line congestion.

Table G.9-16: Impact of transmisson alternatives on congestion costs of Las Aguilas – Moss Landing 230 kV and Manning – Metcalf 500 kV lines

	Congestion Cost ($M/year)			
Case	Las Aguilas-Moss Landing Normal	Las Aguilas-Moss Landing N1	Manning-Metcalf Normal	Manning-Metcalf_N1
Base case	39.5	28.5	8.1	3.8
A1 (reconductoring the Las Aguilas – Moss Landing 230 kV line)	0.0	0.0	16.3	8.0

Production cost and ISO payment results

Table G.9-17 shows the ISO's load payment, generator profile, and transmission revenue from production cost simulation for the Las Aguilas – Moss Landing 230 kV line congestion mitigation alternative.

Three approaches were used to calculate congestion revenue for ISO's ratepayers, as discussed in Section G.2.4:

- S0: The current TEAM approach, i.e. allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's ownership of transmission lines and paths.
- S1: Allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.
- S2: Allocate congestion revenue of entire WECC's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

Table G.9-17: Production cost simulation results for Las Aguilas – Moss Landing 230 kV line congestion mitigation alternative

Case	ISO Load Payment ($M/year)	ISO Gen Profit ($M/year)	ISO Trans Revenue ($M/year)			ISO Net Payment ($M/year)			WECC Production Cost ($M/year)
			S0- Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	S0 - Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	
Base case	20,718	11,388	3,845	2,629	2,922	5,485	6,700	6,408	28,087
A1 (reconductoring the Las Aguilas – Moss Landing 230 kV line)	20,744	11,446	3,812	2,598	2,891	5,487	6,700	6,407	28,075

Cost estimates

As for the cost estimate, in general, the ISO per unit cost was used to estimate the capital cost of the reconductoring the Las Aguilas – Moss Landing 230 kV line. The ISO's screening factor of 1.3 then was applied to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost".

Production savings and benefit to cost ratio

The present value of production cost saving is used to calculate benefit to cost ratio. To calculate the present value, 7% real discount rate was used, and 40-year economic life was assumed for reconductoring. The production cost saving, total cost, and the benefit to cost ratio of the mitigation alternative for this corridor were shown in Table G.9-18.

Table G.9-18: Production Benefits, cost and BCR of Las Aguials – Moss Landing corridor congestion mitigation alternatives

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0- Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	WECC Saving		S0 - Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue
A1 (reconductoring the Las Aguilas – Moss Landing 230 kV line)	-2	0	0	12	200	(0.12)	0.00	0.03

Conclusions

One transmission alternative for mitigating Las Aguilas – Moss Landing 230 kV line congestion was assessed, which is to reconductoring the 230 kV line. This alternative was effective to mitigate the congestion of the 230 kV line, but did not show sufficient benefit to ISO's ratepayers no matter which congestion revenue allocation approach was used. Therefore, it was not recommended as economic-driven upgrade in this planning cycle. It is worth noting that the flow on this corridor is highly correlated with the flow on the Path 15 corridor. Further assessment of this corridor will be conducted in future planning cycles in coordination with Path 15 corridor assessments.