APPENDIX G: Production Cost Simulation and Economic Assessment Detailed Results

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Appendix 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

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.

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[1] 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)

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.

[1] 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)*

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	

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[2] and how they are addressed in the economic study process are summarized and set out in detail in Table G.2-1.

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

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 there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	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 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	LCR benefits are assessed, and valued according to prudent assumptions at this time given the

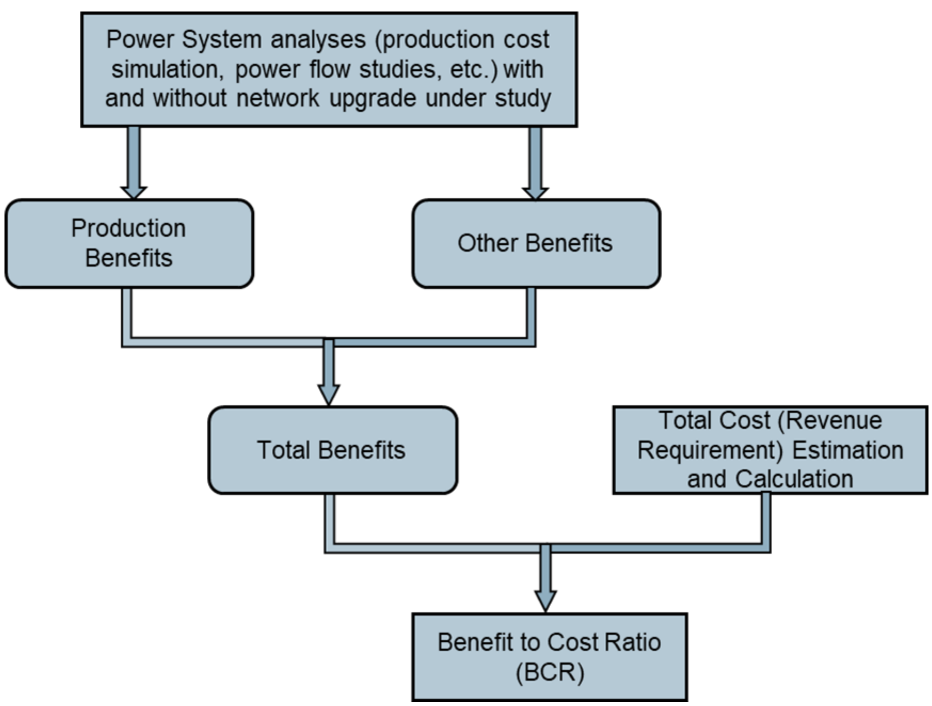
Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the ISO-controlled grid 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.	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 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.	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?
	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.

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.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 2022 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

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

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 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]

When detailed analysis of a high priority study area is required, production-cost simulation and subsequent benefits calculations are conducted for the 10^{th} planning year - in this case, for 2032. For years beyond 2032 the benefits are estimated by extending the 2032-year benefit with an assumed escalation rate.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year’s transmission planning cycle are:

- Economic life of new transmission facilities = 50 years;
- Economic life of upgraded transmission facilities = 40 years;
- Benefits escalation rate beyond year 2031 = 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 above, the

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

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.

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 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:

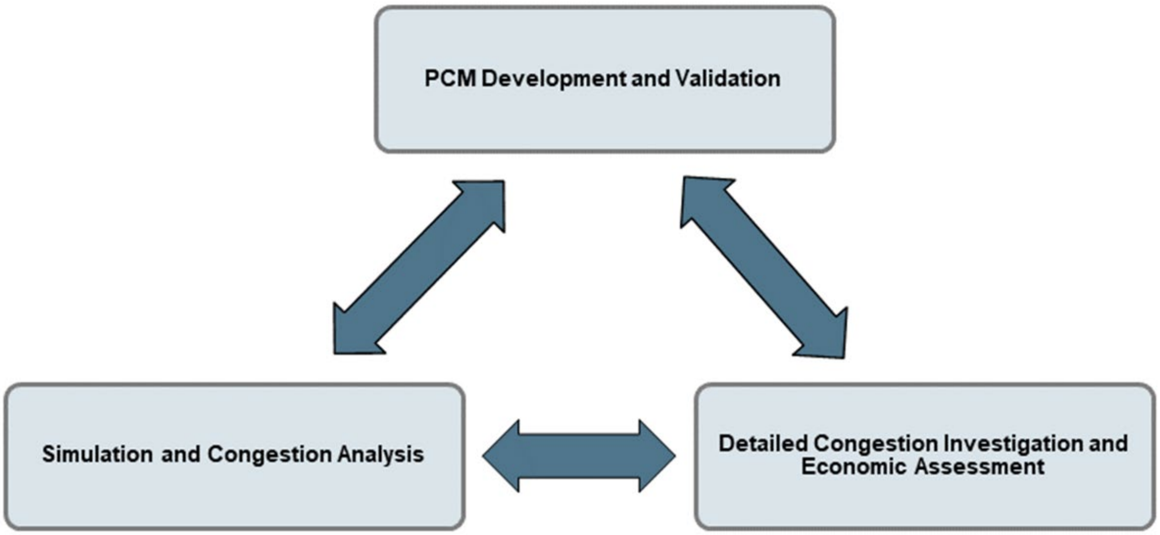
1. Network model (transmission topology, generator location, and load distribution).
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, 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 and database

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™	10.3.45	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)

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.

G.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView 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 2022-2023 transmission planning process PCM development started from the ADS PCM 2032 version 2.0, which was released by WECC on August 22, 2022. Using this databases, the ISO developed the base cases for the ISO 2022-2023 transmission planning process production cost simulation. These base cases included the modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section, and incremental changes in ADS PCM after the ADS PCM 2032 version 2.0 was released.

G.6.2 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 base portfolio PCM used the CEC California Energy Demand Updated Forecast for 2032 with high electrification load, consistent with the demand forecast in the reliability assessment as described in Chapter 2. Differently from previous planning cycles, the sensitivity portfolio PCM in this planning cycle used different load forecast from the Base portfolio PCM, which is the 2035 energy demand updated forecast with high electrification load.

Load modifiers, including DR, DG, AAEE, AATE, and AAFS, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

G.6.3 Generation resources

Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow case for 2032, 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 base portfolio included out-of-state wind with 1062 MW of capacity identified in two alternative locations, Wyoming or Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, Wyoming wind was modeled associated with the TransWest Express project as baseline assumption in the Base portfolio PCM. The Idaho wind scenario was also assessed in the SWIP North project assessment as set out in Section G.10.5.

G.6.4 Network modeling

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 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 in production cost simulations, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the ISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled. These nomograms were developed in the ISO's reliability assessments or identified in the operating procedures. In this planning cycle, the planning PCM continue to model critical credible contingencies in the COI corridor that were identified in the reliability assessment in lieu of COI nomograms, which is consistent with the planning PCM in the last planning cycle.

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.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

G.6.6 Fuel price and CO2 price

The forecast of Natural Gas prices, Coal prices, and CO2 prices were the same as in the ADS PCM 2032. All prices are in 2022 real dollars.

G.6.7 Renewable curtailment price model

The 2022-2023 planning PCM 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.6.8 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[5]. Based on this clarification of the cycle file definition, the battery's operation cost is calculated using the following equation:

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

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

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

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

G.6.9 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, but 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 the 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 *Pmin* 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.7 Base Portfolio Production Cost Simulation Results

G.7.1 Congestion results of Base Portfolio PCM

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.

The results of the congestion assessment in the Base Portfolio PCM are listed in Table G.7-1. Columns "Cost_F" and "Duration_F" is the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns "Cost_B" and "Duration_B" is the cost and duration of congestion in the backward direction. The last two columns were the total cost and total duration, respectively.

Table G.7-1: Congestion in the ISO-controlled grid in the Base Portfolio PCM

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
1	COI Corridor	P66 COI	44,752	949	0	0	44,752	949
2	SCE NOL	KRAMER-VICTOR 230 kV line #1	34,882	1,476	0	0	34,882	1,476
3	Path 26 Corridor	P26 Northern-Southern California	21	13	33,792	1,254	33,813	1,267
4	SCE NOL	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	30,264	1,941	30,264	1,941
5	PG&E Panoche/Oro Loma area	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	18,026	909	1,830	510	19,856	1,419
6	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	13,482	1,190	0	0	13,482	1,190
7	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	13,268	920	13,268	920
8	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	13,213	610	13,213	610
9	SCE W.LA	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	12,457	158	12,457	158
10	SCE NOL	KRAMER-VICTOR 230 kV line #2	12,287	544	0	0	12,287	544
11	PG&E Fresno	GWF_HEP-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	11,614	498	0	0	11,614	498
12	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line #1	11,331	813	0	0	11,331	813

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
13	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	10,077	571	0	0	10,077	571
14	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	8,077	561	8,077	561
15	Path 46 WOR	P46 West of Colorado River (WOR)	7,857	210	0	0	7,857	210
16	PG&E Mosslanding-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	7,641	334	7,641	334
17	COI Corridor	TABLE MTN-TM_TS_11 500 kV line #1	5,568	147	0	0	5,568	147
18	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	5,427	1,265	0	0	5,427	1,265
19	SCE EOL	LUGO-VICTORVL 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV	0	0	5,181	115	5,181	115
20	SDGE/CFE	P45 SDG&E-CFE	2,789	441	1,700	612	4,489	1,053
21	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	4,104	217	0	0	4,104	217
22	PG&E Collinsville-Pittsburg 230 kV	PITSBG F-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-E 230kV	3,609	449	0	0	3,609	449
23	Path 15 Corridor	P15 Midway-LosBanos	3,576	88	0	0	3,576	88
24	PG&E North Valley	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	3,451	90	3,451	90
25	COI Corridor	TM_TS_12-TESLA 500 kV line #1	2,510	54	0	0	2,510	54
26	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	2,486	98	2,486	98
27	PG&E Panoche/Oro Loma area	POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2,004	58	0	0	2,004	58
28	PG&E Fresno	JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	1,761	13	1,761	13
29	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	1,751	523	0	0	1,751	523
30	PDCI	P65 Pacific DC Intertie (PDCI)	141	8	1,362	149	1,503	157
31	SDGE/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	1,497	438	1,497	438
32	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	1,127	37	0	0	1,127	37
33	SCE NOL	P60 Inyo-Control 115 kV Tie	0	0	1,039	572	1,039	572
34	Path 15 Corridor	LB_GT_11-GATES 500 kV line #1	0	0	741	34	741	34
35	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	738	201	0	0	738	201
36	PG&E Collinsville-Pittsburg 230 kV	COLLNSVL-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	615	75	0	0	615	75
37	SCE NOL	CALCITE-LUGO 230 kV line #1	597	601	0	0	597	601
38	PG&E Sierra	P24 PG&E-Sierra	0	0	583	185	583	185

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
39	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	528	16	528	16
40	SCE W.LA	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	449	20	449	20
41	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	445	189	0	0	445	189
42	GridLiance/VEA	INNOVATION 138/138 kV transformer #1	420	30	0	0	420	30
43	SCE NOL	VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	418	204	418	204
44	PG&E North Valley	POE-RIO OSO 230 kV line #1	409	108	0	0	409	108
45	Path 41 Sylmar transformer	P41 Sylmar to SCE	401	85	0	0	401	85
46	SCE EOL	P61 Lugo-Victorville 500 kV Line	166	6	213	76	379	82
47	PG&E Tesla-Los Banos 500 kV	TESLA-LOSBANOS 500 kV line #1	0	0	369	8	369	8
48	SCE Vincent	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	354	7	0	0	354	7
49	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #1	0	0	344	13	344	13
50	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	340	16	340	16
51	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	308	16	308	16
52	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	136	3	149	15	285	18
53	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	281	38	281	38
54	PG&E Panoche/Oro Loma area	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	268	118	268	118
55	SDGE/CFE	IV PFC1 230/230 kV transformer #1	244	31	0	0	244	31
56	PG&E Quinto-Los Banos 230 kV	QUINTO_SS-LOSBANOS 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	0	0	234	10	234	10
57	SCE NOL	VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	1	230	822	230	823
58	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	224	53	0	0	224	53
59	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	204	9	204	9
60	SCE NOL	VICTOR-LUGO 230 kV line #1	161	15	0	0	161	15
61	SCE Tehachapi	WLDRNESS TAP-WINDSTAR1 230 kV line #1	158	275	0	0	158	275
62	SDGE San Diego Southern	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	154	14	154	14

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
63	GridLiance/VEA	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	113	65	0	0	113	65
64	SCE NOL	ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	95	32	95	32
65	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	80	5	0	0	80	5
66	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	77	4	0	0	77	4
67	SCE NOL	VICTOR-LUGO 230 kV line #3	66	4	0	0	66	4
68	SDGE San Diego Northern	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	42	15	20	7	62	22
69	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	55	2	55	2
70	SCE Vincent-MiraLoma 500kV	EAST TS-MIRALOMA 500 kV line #1	0	0	55	1	55	1
71	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	46	8	0	0	46	8
72	PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	45	451	0	1	45	452
73	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	40	1	40	1
74	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line #1	0	0	39	1	39	1
75	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	33	44	0	0	33	44
76	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	31	7	31	7
77	SCE NOL	VICTOR-LUGO 230 kV line #4	26	2	0	0	26	2
78	SDGE/CFE	IV PFC1 230/230 kV transformer #2	24	6	0	0	24	6
79	PG&E Fresno	WARNERVL-WILSONRCTR 230 kV line #1	13	1	0	0	13	1
80	PG&E GBA	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	13	1	0	0	13	1
81	PG&E Fresno	GATES D-CALFLATSSS 230 kV line #1	0	0	13	4	13	4
82	SCE W.LA	MESACALS-LAGUBELL 230 kV line #2	13	19	0	0	13	19
83	SDGE San Diego Northern	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	8	5	0	0	8	5
84	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DeservtView 230 kV with RAS	8	6	0	0	8	6
85	PG&E Tesla-Metcalf 500 kV	TESLA-METCALF 500 kV line #1	8	1	0	0	8	1
86	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	7	1	0	0	7	1

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
87	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	6	19	6	19
88	SCE E.LA	ALBERHIL-VALLEYSC 500 kV line #1	0	0	6	1	6	1
89	SDGE San Diego Northern	ENCINATP-SANLUSRY 230 kV line, subject to SDGE N-1 EN-SLR 230 kV with RAS	5	2	0	0	5	2
90	COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	4	1	0	0	4	1
91	PG&E GBA	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	4	1	0	0	4	1
92	PG&E GBA	MARSHLD1-C.COSTAPPD 230 kV line #1	4	2	0	0	4	2
93	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	4	3	0	0	4	3
94	PG&E GBA	MARSHLD2-C.COSTAPPD 230 kV line #2	3	1	0	0	3	1
95	PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	1	5	0	0	1	5
96	PG&E Humboldt	HUMBOLDT-BRDGVLLE 115 kV line #1	1	5	0	0	1	5
97	PG&E Fresno	WILSONRCTR-WILSONPGAE 230 kV line #BP	1	1	0	0	1	1
98	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #2	0	0	1	1	1	1

The branch group or local-area information is provided in the first column in Table G.7-1. The branch groups are identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestion subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results have been ranked based on the congestion cost. The potential congestion across specific branch groups and local areas in 2032 is summarized in Table G.7-2.

Table G.7-2: Aggregated potential congestion in the ISO-controlled grid in 2032

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	SCE NOL	80.06	6,214
2	COI Corridor	52.83	1,151
3	Path 26 Corridor	47.32	1,896
4	GridLiance/VEA	40.37	3,547
5	PG&E Panoche/Oro Loma area	32.24	2,213
6	SDGE San Diego Southern	13.91	1,018
7	PG&E Fresno	13.81	1,012
8	SCE W.LA	12.92	197
9	Path 46 WOR	7.86	210
10	PG&E Mosslanding-Las Aguilas 230 kV	7.64	334
11	Path 15 Corridor	7.49	253
12	SDGE/CFE	6.25	1,528
13	SCE EOL	5.56	197
14	SCE Antelope 66kV	5.43	1,265
15	PG&E Collinsville-Pittsburg 230 kV	4.29	532
16	PG&E North Valley	3.86	198
17	PDCI	1.50	157
18	SCE Eastern	0.79	27
19	SCE J.Hinds-Mirage	0.74	201
20	PG&E Sierra	0.58	185
21	Path 41 Sylmar transformer	0.40	85
22	PG&E Tesla-Los Banos 500 kV	0.37	8
23	SCE Vincent	0.35	7
24	Path 42 Corridor	0.34	14
25	PG&E GBA	0.29	66
26	PG&E Quinto-Los Banos 230 kV	0.23	10
27	SCE Tehachapi	0.16	275
28	Path 25 PACW-PG&E 115 kV	0.08	4
29	SDGE San Diego Northern	0.08	29
30	SCE Vincent-MiraLoma 500kV	0.05	1
31	PG&E Tesla-Metcalf 500 kV	0.01	1
32	SCE Northern	0.01	19
33	SCE E.LA	0.01	1
34	PG&E Humboldt	0.00	10

G.7.2 Curtailment results of Base Portfolio PCM

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.

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

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Tehachapi	31,060	743	31,804	2.34%
PG&E Fresno/Kern	17,924	418	18,342	2.28%
SCE Eastern	15,326	618	15,944	3.88%
SDGE IV	8,296	0	8,296	0.00%
SCE NOL	7,403	403	7,805	5.16%
PG&E Diablo OSW	7,635	98	7,734	1.27%
GridLiance/VEA	7,284	170	7,454	2.28%
NM	6,281	230	6,511	3.53%
AZ	5,621	166	5,786	2.86%
SCE EOL	5,465	125	5,590	2.23%
PG&E Central Valley	5,448	15	5,463	0.27%
WY	3,890	147	4,037	3.64%
PG&E Central Coast	2,797	53	2,849	1.85%
SCE Vestal-Rector	2,349	65	2,414	2.69%
PG&E North Valley	2,240	3	2,242	0.13%
NW	1,876	183	2,059	8.90%
SCE Ventura	1,288	51	1,340	3.83%
SCE Antelope 66 kV	926	23	949	2.39%
PG&E Humboldt OSW	618	2	620	0.30%
SCE LA Basin	315	5	320	1.46%
IID	308	0	309	0.05%
SDGE San Diego	262	0	262	0.01%
PG&E GBA	110	1	110	0.71%
Total	**134,719**	**3,518**	**138,237**	**2.54%**

G.8 Sensitivity Portfolio Production Cost Simulation Results

Three transmission interconnection alternatives for the incremental Humboldt Bay offshore wind were studied:

- Alternative 1 – The 1487 MW of Humboldt Bay offshore wind is injecting at the Fern Road 500 kV bus.
- Alternative 2 - The 1487 MW of Humboldt Bay offshore wind is injecting at the proposed BayHub 230 kV bus.
- Alternative 3 - The 1487 MW of Humboldt Bay offshore wind is injecting at the Collinsville 500 kV bus, which was an approved transmission upgrade in the last planning cycle.

G.8.1 Congestion results of Sensitivity Portfolio PCM

G.8.1.1 Alternative 1 congestion results

The results of the congestion assessment in the sensitivity portfolio PCM for the Alternative 1 case with Humboldt Bay offshore wind at Fern Road is listed in Table G.8-1. Columns “Cost_F” and “Duration_F” is the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns “Cost_B” and “Duration_B” is the cost and duration of congestion in the backward direction. The last two columns presents the total cost and total duration, respectively.

Table G.8-1: Congestion in the ISO-controlled grid in the Sensitivity Portfolio PCM Alternative 1 with Humboldt Bay Offshore Wind at Fern Road

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
1	PG&E Mosslanding-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	116,441	1,838	116,441	1,838
2	Path 46 WOR	P46 West of Colorado River (WOR)	83,565	287	0	0	83,565	287
3	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	80,234	4,221	0	0	80,234	4,221
4	PG&E Collinsville-Pittsburg 230 kV	COLLNSVL-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	65,752	1,574	0	0	65,752	1,574
5	SCE W.LA	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	64,593	1,062	64,593	1,062
6	PG&E Fresno	GWF_HEP-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	61,598	1,609	0	0	61,598	1,609
7	SCE EOL	LUGO-VICTORVL 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV	0	0	60,331	107	60,331	107
8	COI Corridor	P66 COI	54,580	544	0	0	54,580	544
9	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line #1	48,969	2,704	0	0	48,969	2,704
10	SCE NOL	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	41,582	2,325	41,582	2,325
11	COI Corridor	TABLE MTN-TM_TS_11 500 kV line #1	31,620	483	0	0	31,620	483
12	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	28,533	795	0	0	28,533	795
13	PG&E Panoche/Oro Loma area	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	28,163	1,566	248	342	28,411	1,908
14	SCE NOL	VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	27,579	2,227	27,579	2,227
15	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	25,209	539	25,209	539
16	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	21,059	3,046	0	0	21,059	3,046
17	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	20,859	1,532	20,859	1,532
18	SCE EOL	P61 Lugo-Victorville 500 kV Line	19,046	7	1,188	333	20,234	340
19	SCE W.LA	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	19,757	338	19,757	338
20	GridLiance/VEA	AMARGOSA-SANDY 138 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	0	0	19,208	1,741	19,208	1,741
21	PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line #1	17,039	480	0	0	17,039	480
22	PG&E Fresno	JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	15,902	105	15,902	105

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
23	SCE Vincent	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	14,288	498	0	0	14,288	498
24	Path 15 Corridor	P15 Midway-LosBanos	14,014	536	0	0	14,014	536
25	COI Corridor	TM_TS_12-TESLA 500 kV line #1	13,774	157	0	0	13,774	157
26	SCE NOL	KRAMER-VICTOR 230 kV line #1	13,379	1,539	0	0	13,379	1,539
27	Path 26 Corridor	P26 Northern-Southern California	1,069	238	11,798	550	12,867	788
28	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	11,003	696	0	0	11,003	696
29	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	10,735	180	0	0	10,735	180
30	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 SX-PQ 230 kV	0	0	10,734	18	10,734	18
31	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	8,461	631	8,461	631
32	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	8,323	531	8,323	531
33	PG&E Collinsville-Pittsburg 230 kV	PITSBG F-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-E 230kV	7,285	1,216	0	0	7,285	1,216
34	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	0	0	7,079	9	7,079	9
35	SDGE/CFE	P45 SDG&E-CFE	3,573	534	2,972	181	6,544	715
36	SCE E.LA	CHINO-MIRALOME 230 kV line, subject to SCE N-2 MiraLomaW-Chino #1 and #2 230kV	0	0	6,526	123	6,526	123
37	COI Corridor	RM_TM_22-TABLE MTN 500 kV line #2	6,352	42	0	0	6,352	42
38	SCE NOL	VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	1	8	6,202	1,862	6,202	1,870
39	SDGE/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	4,840	656	4,840	656
40	SCE NOL	KRAMER-VICTOR 230 kV line #2	4,803	645	0	0	4,803	645
41	SCE Vincent	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	4,569	224	4,569	224
42	SCE W.LA	MESACALS-LAGUBELL 230 kV line #2	4,542	331	0	0	4,542	331
43	SCE Eastern	RP_PALOVRDE-PALOVRDE 500 kV line #1	0	0	4,509	3	4,509	3
44	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	3,918	1,482	0	0	3,918	1,482
45	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	3,794	32	3,794	32
46	SDGE San Diego Southern	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	3,555	132	3,555	132
47	PG&E Sierra	P24 PG&E-Sierra	0	0	3,541	457	3,541	457
48	SCE NOL	ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	3,414	725	3,414	725
49	SCE NOL	P60 Inyo-Control 115 kV Tie	553	577	2,839	1,126	3,392	1,703

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
50	Path 15 Corridor	LB_GT_11-GATES 500 kV line #1	0	0	3,345	69	3,345	69
51	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	2,950	413	2,950	413
52	Path 41 Sylmar transformer	P41 Sylmar to SCE	2,865	51	0	0	2,865	51
53	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	2,764	79	0	0	2,764	79
54	GridLiance/VEA	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	2,438	1,268	0	1	2,438	1,269
55	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	2,408	86	0	0	2,408	86
56	COI Corridor	RM_TM_12-TABLE MTN 500 kV line #1	2,213	1	0	0	2,213	1
57	PG&E Tesla-Los Banos 500 kV	TESLA-LOSBANOS 500 kV line #1	0	0	2,143	73	2,143	73
58	PDCI	P65 Pacific DC Intertie (PDCI)	399	9	1,509	204	1,908	213
59	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	2	1,745	282	1,745	284
60	SDGE San Diego Northern	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	23	5	1,628	171	1,651	176
61	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	1,521	5	0	0	1,521	5
62	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	1,511	10	1,511	10
63	PG&E Panoche/Oro Loma area	POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,342	37	0	0	1,342	37
64	PG&E North Valley	POE-RIO OSO 230 kV line #1	1,135	144	0	0	1,135	144
65	SDGE/CFE	IV PFC1 230/230 kV transformer #1	1,127	178	0	0	1,127	178
66	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	1,113	295	0	0	1,113	295
67	SCE Vincent-MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	1,069	3	0	0	1,069	3
68	SCE NOL	CALCITE-LUGO 230 kV line #1	1,013	1,604	0	0	1,013	1,604
69	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	1	3	942	111	943	114
70	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	790	46	0	0	790	46
71	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #1	0	0	580	82	580	82
72	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	512	545	512	545
73	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line #1	0	0	496	10	496	10
74	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	469	80	0	0	469	80
75	SCE Tehachapi	WLDRNESS TAP-WINDSTAR1 230 kV line #1	449	317	0	0	449	317
76	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	441	1	0	0	441	1

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
77	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E FRESNO N-2 GATES-MUSTANG SW STA 230kV	0	0	441	155	441	155
78	SDGE San Diego Northern	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	403	66	0	0	403	66
79	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DesertView 230 kV with RAS	390	39	0	0	390	39
80	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	376	44	0	0	376	44
81	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	350	1	0	0	350	1
82	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	335	64	0	0	335	64
83	PG&E Fresno	WARNERVL-WILSONRCTR 230 kV line #1	333	18	0	0	333	18
84	PG&E Kern 230kV	WND GPJ1-WHEELER 230 kV line #1	0	0	314	156	314	156
85	PG&E Panoche/Oro Loma area	LE GRAND-WILSONPGAE 115 kV line #1	295	64	0	0	295	64
86	SCE E.LA	ALBERHIL-VALLEYSC 500 kV line #1	0	0	294	36	294	36
87	PG&E North Valley	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	288	75	288	75
88	PG&E Quinto-Los Banos 230 kV	QUINTO_SS-LOSBANOS 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	0	0	271	10	271	10
89	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	270	52	270	52
90	SCE W.LA	BARRE-VILLA PK 230 kV line, subject to SCE N-1 Lewis-Barre 230kV	0	0	255	15	255	15
91	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #2	0	0	231	20	231	20
92	SDGE/CFE	IV PFC1 230/230 kV transformer #2	221	43	0	0	221	43
93	SDGE San Diego Northern	TALEGA-S.ONOFRE 230 kV line #1	0	0	184	64	184	64
94	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	178	7	178	7
95	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	165	20	165	20
96	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	148	12	0	0	148	12
97	SCE Vincent-MiraLoma 500kV	EAST TS-MIRALOMA 500 kV line #1	0	0	136	10	136	10
98	SCE Pardee 230 kV	PARDEE-VINCENT 230 kV line #2	0	0	132	10	132	10
99	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	131	2	131	2

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
100	PG&E Fresno	PANOCHE1-KAMM 115 kV line #1	0	0	118	206	118	206
101	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	111	4	111	4
102	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	109	7	0	0	109	7
103	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	100	30	100	30
104	SCE Pardee 230 kV	ANTELOPE-PARDEE 230 kV line #1	95	11	0	0	95	11
105	PG&E Panoche/Oro Loma area	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	87	115	87	115
106	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	78	24	5	5	83	29
107	PG&E Fresno	WILSONRCTR-WILSONPGAE 230 kV line #BP	82	4	0	0	82	4
108	PG&E Tracy-Los Banos 500 kV	TRACY-LOSBANOS 500 kV line #1	0	0	66	1	66	1
109	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	62	22	0	0	62	22
110	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	62	7	62	7
111	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	47	11	0	0	47	11
112	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	43	5	0	0	43	5
113	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	42	2	42	2
114	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	36	72	36	72
115	SCE Vincent-MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	35	4	35	4
116	PG&E Tesla-Metcalf 500 kV	TESLA-METCALF 500 kV line #1	29	1	0	0	29	1
117	PG&E Fresno	SLATE-MUSTANG3N4 230 kV line #1	23	4	0	0	23	4
118	SCE Vincent-MiraLoma 500kV	MESA CAL-WEST TS 500 kV line #1	0	0	20	2	20	2
119	PG&E North Valley	TABLE MTN D-PALERMO 230 kV line, subject to PG&E-BANC N-1 Maxwell-Tracy 500kV	15	3	0	0	15	3
120	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	14	4	0	0	14	4
121	PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	9	317	0	0	9	317
122	PG&E Kern 230kV	WND GPJ2-WHEELER 230 kV line #1	0	0	8	7	8	7
123	PG&E GBA	BUENAVJ2-BITTERWATRSS 230 kV line #2	0	0	7	13	7	13

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
124	PG&E GBA	NEWARK E-NWK DIST 230 kV line #1	5	1	0	0	5	1
125	PG&E North Valley	COTWD_E-ROUND MT 230 kV line #3	0	0	5	1	5	1
126	PG&E Central Cost	MORROBAY-SOLARSS 230 kV line #1	0	0	5	5	5	5
127	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line #1	5	2	0	0	5	2
128	SCE Pardee 230 kV	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	4	23	0	0	4	23
129	PG&E Humboldt	HUMBOLDT-BRDGVLLE 115 kV line #1	4	8	0	0	4	8
130	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	3	6	0	0	3	6
131	PG&E Fresno	SNJQJCT-GFFNJCT 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	3	12	0	0	3	12
132	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	3	1	3	1
133	PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	3	7	0	0	3	7
134	PG&E GBA	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	2	2	0	0	2	2
135	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-1 Tranqlty-Helm 230kV	2	10	0	0	2	10
136	PG&E Fresno	HENTAP1-MUSTANGSS 230 kV line #1	0	0	1	1	1	1
137	SCE NOL	VICTOR-LUGO 230 kV line #1	1	1	0	0	1	1

Table G.8-2 lists the aggregated congestion results of the sensitivity portfolio PCM Alternative 1 case with the Humboldt Bay offshore wind interconnected at Fern Road.

Table G.8-2: Aggregated congestion in Sensitivty portfolio PCM Alternative 1 with Humboldt Bay Offshore Wind at Fern Road

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	GridLiance/VEA	193.16	14,552
2	PG&E Mosslanding-Las Aguilas 230 kV	116.44	1,838
3	COI Corridor	108.54	1,227
4	SCE NOL	101.37	12,639
5	SDGE San Diego Southern	90.92	1,759
6	SCE W.LA	89.24	1,762
7	Path 46 WOR	83.57	287
8	PG&E Fresno	82.25	2,900
9	SCE EOL	80.57	447
10	PG&E Collinsville-Pittsburg 230 kV	73.71	2,807
11	PG&E Panoche/Oro Loma area	41.52	2,870
12	Path 26 Corridor	21.87	1,433
13	Path 15 Corridor	20.58	1,105
14	SCE Vincent	18.86	722
15	SCE Eastern	18.52	682
16	PG&E/TID Exchequer	17.04	480
17	SDGE/CFE	12.73	1,592
18	SCE E.LA	6.82	159
19	SCE Antelope 66kV	3.92	1,482
20	PG&E Sierra	3.54	457
21	Path 41 Sylmar transformer	2.87	51
22	SCE J.Hinds-Mirage	2.41	86
23	SDGE San Diego Northern	2.24	306
24	PG&E Tesla-Los Banos 500 kV	2.14	73
25	PDCI	1.91	213
26	PG&E North Valley	1.44	223
27	SCE Vincent-MiraLoma 500kV	1.26	19
28	SCE Northern	1.21	374
29	PG&E Kern 230kV	0.90	730
30	Path 42 Corridor	0.81	102
31	PG&E GBA	0.53	98
32	SCE Tehachapi	0.45	317
33	PG&E Quinto-Los Banos 230 kV	0.27	10
34	SCE Pardee 230 kV	0.23	44
35	PG&E Tracy-Los Banos 500 kV	0.07	1
36	PG&E Tesla-Metcalf 500 kV	0.03	1
37	Path 25 PACW-PG&E 115 kV	0.01	4
38	PG&E Humboldt	0.01	15
39	PG&E Central Cost	0.00	5
40	PG&E Tesla 230 kV	0.00	1

G.8.1.2 Alternative 2 congestion results

The results of the congestion assessment in the sensitivity portfolio PCM of the Alternative 2 case with the Humboldt Bay offshore wind at Bay Hub is listed in Table G.8-3. Columns "Cost_F" and "Duration_F" is the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns "Cost_B" and "Duration_B" is the cost and duration of congestion in the backward direction. The last two columns provide the total cost and total duration, respectively.

Table G.8-3: Congestion in the ISO-controlled grid in the Sensitivity Portfolio PCM Alternative 2 with Humboldt Bay Offshore Wind at Bay Hub

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
1	PG&E Mosslanding-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	93,637	1,602	93,637	1,602
2	Path 46 WOR	P46 West of Colorado River (WOR)	85,408	279	0	0	85,408	279
3	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	78,187	4,246	0	0	78,187	4,246
4	COI Corridor	P66 COI	78,079	704	0	0	78,079	704
5	SCE W.LA	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	66,962	1,066	66,962	1,066
6	SCE EOL	LUGO-VICTORVL 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV	0	0	63,074	118	63,074	118
7	PG&E Fresno	GWF_HEP-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	61,100	1,643	0	0	61,100	1,643
8	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line #1	50,531	2,712	0	0	50,531	2,712
9	SCE NOL	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	42,753	2,327	42,753	2,327
10	SCE EOL	P61 Lugo-Victorville 500 kV Line	30,333	10	1,409	375	31,742	385
11	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	31,142	837	0	0	31,142	837
12	PG&E Panoche/Oro Loma area	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	28,258	1,632	237	317	28,495	1,949
13	SCE NOL	VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	27,448	2,227	27,448	2,227
14	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	26,985	563	26,985	563
15	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	21,295	1,552	21,295	1,552
16	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	20,621	3,003	0	0	20,621	3,003
17	GridLiance/VEA	AMARGOSA-SANDY 138 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	0	0	18,877	1,748	18,877	1,748
18	SCE W.LA	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	17,785	319	17,785	319
19	PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line #1	16,770	472	0	0	16,770	472

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
20	PG&E Collinsville-Pittsburg 230 kV	COLLNSVL-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	15,945	674	0	0	15,945	674
21	PG&E Fresno	JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	14,428	96	14,428	96
22	Path 15 Corridor	P15 Midway-LosBanos	14,408	532	0	0	14,408	532
23	SCE Vincent	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	13,944	537	0	0	13,944	537
24	Path 26 Corridor	P26 Northern-Southern California	1,312	255	12,094	537	13,406	792
25	SCE NOL	KRAMER-VICTOR 230 kV line #1	13,300	1,550	0	0	13,300	1,550
26	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	13,102	830	0	0	13,102	830
27	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	11,588	178	0	0	11,588	178
28	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 SX-PQ 230 kV	0	0	11,297	17	11,297	17
29	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	8,534	644	8,534	644
30	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	8,456	534	8,456	534
31	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	0	0	7,368	8	7,368	8
32	SCE E.LA	CHINO-MIRALOME 230 kV line, subject to SCE N-2 MiraLomaW-Chino #1 and #2 230kV	0	0	7,292	130	7,292	130
33	SDGE/CFE	P45 SDG&E-CFE	3,596	549	3,260	174	6,857	723
34	PG&E GBA	BAYHUB-LS ESTRS 230 kV line #1	6,572	452	0	0	6,572	452
35	SCE NOL	VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	1	12	6,341	1,842	6,342	1,854
36	SCE Eastern	RP_PALOVRDE-PALOVRDE 500 kV line #1	0	1	5,595	4	5,595	5
37	SDGE/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	5,035	615	5,035	615
38	SCE W.LA	MESACALS-LAGUBELL 230 kV line #2	4,656	351	0	0	4,656	351
39	SCE NOL	KRAMER-VICTOR 230 kV line #2	4,623	634	0	0	4,623	634
40	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	4,433	32	4,433	32
41	SDGE San Diego Southern	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	4,287	142	4,287	142
42	SCE Vincent	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	4,013	218	4,013	218
43	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	3,986	1,481	0	0	3,986	1,481
44	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	3,777	77	0	0	3,777	77
45	PG&E Sierra	P24 PG&E-Sierra	0	0	3,562	374	3,562	374
46	Path 15 Corridor	LB_GT_11-GATES 500 kV line #1	0	0	3,463	66	3,463	66
47	SCE NOL	P60 Inyo-Control 115 kV Tie	497	515	2,879	1,118	3,375	1,633
48	SCE NOL	ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	3,344	746	3,344	746
49	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	2,815	88	0	0	2,815	88

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
50	PG&E Collinsville-Pittsburg 230 kV	PITSBG F-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-E 230kV	2,634	312	0	0	2,634	312
51	GridLiance/VEA	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	2,568	1,319	1	2	2,568	1,321
52	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	2,421	353	2,421	353
53	PDCI	P65 Pacific DC Intertie (PDCI)	563	14	1,670	213	2,234	227
54	COI Corridor	TABLE MTN-TM_TS_11 500 kV line #1	2,226	16	0	0	2,226	16
55	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	2,140	7	0	0	2,140	7
56	PG&E Tesla-Los Banos 500 kV	TESLA-LOSBANOS 500 kV line #1	0	0	2,116	84	2,116	84
57	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	1	1,794	288	1,794	289
58	SDGE San Diego Northern	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	11	3	1,663	172	1,675	175
59	Path 41 Sylmar transformer	P41 Sylmar to SCE	1,623	52	0	0	1,623	52
60	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	1,620	12	1,620	12
61	PG&E Panoche/Oro Loma area	POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,336	43	0	0	1,336	43
62	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	1,132	289	0	0	1,132	289
63	PG&E North Valley	POE-RIO OSO 230 kV line #1	1,119	147	0	0	1,119	147
64	SDGE/CFE	IV PFC1 230/230 kV transformer #1	1,035	167	0	0	1,035	167
65	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	907	47	0	0	907	47
66	SCE Vincent-MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	901	3	0	0	901	3
67	SCE NOL	CALCITE-LUGO 230 kV line #1	901	1,593	0	0	901	1,593
68	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	1	3	652	105	653	108
69	PG&E Fresno	WARNERVL-WILSONRCTR 230 kV line #1	534	22	0	0	534	22
70	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	510	542	510	542
71	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #1	0	0	478	70	478	70
72	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	441	1	0	0	441	1
73	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E FRESNO N-2 GATES-MUSTANG SW STA 230kV	0	0	424	156	424	156
74	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	390	78	0	0	390	78
75	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	389	48	0	0	389	48
76	SDGE San Diego Northern	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	387	67	0	0	387	67
77	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	1	368	56	368	57
78	SCE Tehachapi	WLDRNESS TAP-WINDSTAR1 230 kV line #1	368	315	0	0	368	315

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
79	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DesertView 230 kV with RAS	364	64	0	0	364	64
80	PG&E North Valley	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	363	72	363	72
81	PG&E Panoche/Oro Loma area	LE GRAND-WILSONPGAE 115 kV line #1	331	71	0	0	331	71
82	SDGE San Diego Northern	TALEGA-S.ONOFRE 230 kV line #1	0	0	290	76	290	76
83	SCE W.LA	BARRE-VILLA PK 230 kV line, subject to SCE N-1 Lewis-Barre 230kV	0	0	274	19	274	19
84	PG&E Quinto-Los Banos 230 kV	QUINTO_SS-LOSBANOS 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	0	0	258	7	258	7
85	PG&E Kern 230kV	WND GPJ1-WHEELER 230 kV line #1	0	0	257	153	257	153
86	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	254	1	0	0	254	1
87	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line #1	0	0	251	6	251	6
88	SCE E.LA	ALBERHIL-VALLEYSC 500 kV line #1	0	0	249	42	249	42
89	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	199	7	199	7
90	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	191	4	191	4
91	PG&E Fresno	PANOCHE1-KAMM 115 kV line #1	0	0	169	228	169	228
92	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	156	24	156	24
93	SDGE/CFE	IV PFC1 230/230 kV transformer #2	143	43	0	0	143	43
94	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	117	11	0	0	117	11
95	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	105	24	6	4	111	28
96	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	103	9	0	0	103	9
97	SCE Vincent-MiraLoma 500kV	EAST TS-MIRALOMA 500 kV line #1	0	0	101	8	101	8
98	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	98	9	0	0	98	9
99	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	87	9	0	0	87	9
100	PG&E Panoche/Oro Loma area	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	85	111	85	111
101	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #2	0	0	79	24	79	24
102	SCE Vincent-MiraLoma 500kV	MESA CAL-WEST TS 500 kV line #1	0	0	73	6	73	6
103	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	71	1	71	1
104	COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	65	1	0	0	65	1
105	SCE Pardee 230 kV	ANTELOPE-PARDEE 230 kV line #1	64	10	0	0	64	10
106	SCE Pardee 230 kV	PARDEE-VINCENT 230 kV line #2	0	0	63	11	63	11
107	COI Corridor	TM_TS_12-TESLA 500 kV line #1	58	3	0	0	58	3
108	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	54	14	54	14
109	PG&E Tracy-Los Banos 500 kV	TRACY-LOSBANOS 500 kV line #1	0	0	53	2	53	2
110	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	36	22	0	0	36	22

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
111	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	35	67	35	67
112	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	27	2	27	2
113	SCE Vincent-MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	24	2	24	2
114	PG&E Fresno	SLATE-MUSTANG3N4 230 kV line #1	21	5	0	0	21	5
115	PG&E Humboldt	HUMBOLDT-BRDGVLLE 115 kV line #1	19	18	0	0	19	18
116	PG&E Fresno	WILSONRCTR-WILSONPGAE 230 kV line #BP	16	1	0	0	16	1
117	PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	9	309	0	0	9	309
118	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	9	7	9	7
119	SCE EOL	HAE SVC-HAE SVCL 500 kV line #1	8	1	0	0	8	1
120	PG&E Tesla-Metcalf 500 kV	TESLA-METCALF 500 kV line #1	7	1	0	0	7	1
121	PG&E Central Cost	MORROBAY-SOLARSS 230 kV line #1	0	0	7	3	7	3
122	GridLiance/VEA	AMARGOSA-SANDY 138 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	0	0	7	1	7	1
123	PG&E GBA	BUENAVJ2-BITTERWATRSS 230 kV line #2	0	0	7	15	7	15
124	PG&E GBA	EMBRCDRD-PTR_SHNT 230 kV line #1	0	0	5	3	5	3
125	PG&E GBA	PITSBG D-PITSBG E 230 kV line #1	0	0	4	2	4	2
126	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	4	7	0	0	4	7
127	SCE Pardee 230 kV	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	4	17	0	0	4	17
128	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	4	5	0	0	4	5
129	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-1 Tranqlty-Helm 230kV	2	14	0	0	2	14
130	PG&E Fresno	SNJQJCT-GFFNJCT 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2	13	0	0	2	13
131	SCE NOL	VICTOR-LUGO 230 kV line #1	2	1	0	0	2	1
132	PG&E Kern 230kV	WND GPJ2-WHEELER 230 kV line #1	0	0	2	7	2	7
133	PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	2	9	0	0	2	9
134	PG&E Fresno	HENTAP1-MUSTANGSS 230 kV line #1	0	0	1	2	1	2
135	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line #1	1	1	0	0	1	1
136	PG&E GBA	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	1	1	0	0	1	1

Table G.8-4 shows the aggregated congestion results of the sensitivity portfolio PCM Alternative 2 case with the Humboldt Bay offshore wind interconnected at Bay Hub.

Table G.8-4: Aggregated congestion in Sensitivty portfolio PCM Alternative 2 with Humboldt Bay Offshore Wind at Bay Hub

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	GridLiance/VEA	192.45	14,647
2	SCE NOL	102.09	12,565
3	SDGE San Diego Southern	99.28	1,831
4	SCE EOL	94.82	504
5	PG&E Mosslanding-Las Aguilas 230 kV	93.64	1,602
6	SCE W.LA	89.77	1,771
7	Path 46 WOR	85.41	279
8	COI Corridor	80.43	724
9	PG&E Fresno	80.03	2,889
10	PG&E Panoche/Oro Loma area	43.74	3,058
11	Path 26 Corridor	22.58	1,452
12	Path 15 Corridor	20.90	1,090
13	SCE Eastern	20.44	698
14	PG&E Collinsville-Pittsburg 230 kV	18.83	992
15	SCE Vincent	17.96	755
16	PG&E/TID Exchequer	16.77	472
17	SDGE/CFE	13.07	1,548
18	SCE E.LA	7.54	172
19	PG&E GBA	6.61	475
20	SCE Antelope 66kV	3.99	1,481
21	PG&E Sierra	3.56	374
22	SCE J.Hinds-Mirage	2.81	88
23	SDGE San Diego Northern	2.35	318
24	PDCI	2.23	227
25	PG&E Tesla-Los Banos 500 kV	2.12	84
26	Path 41 Sylmar transformer	1.62	52
27	PG&E North Valley	1.48	219
28	SCE Northern	1.18	363
29	SCE Vincent-MiraLoma 500kV	1.10	19
30	PG&E Kern 230kV	0.81	724
31	Path 42 Corridor	0.56	94
32	SCE Tehachapi	0.37	315
33	PG&E Quinto-Los Banos 230 kV	0.26	7
34	PG&E Tesla 230 kV	0.20	7
35	SCE Pardee 230 kV	0.13	38
36	Path 25 PACW-PG&E 115 kV	0.10	9
37	PG&E Tracy-Los Banos 500 kV	0.05	2
38	PG&E Humboldt	0.02	27
39	PG&E Tesla-Metcalf 500 kV	0.01	1
40	PG&E Central Cost	0.01	3

G.8.1.3 Alternative 3 congestion results

The results of the congestion assessment in the sensitivity portfolio PCM Alternative 3 case with Humboldt Bay offshore wind interconnected to Collinsville is listed in Table G.8-5. Columns “Cost_F” and “Duration_F” is the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns “Cost_B” and “Duration_B” is the cost and duration of congestion in the backward direction. The last two columns presents the total cost and total duration, respectively.

Table G.8-5: Congestion in the ISO-controlled grid in the Sensitivity Portfolio PCM Alternative 3 with Humboldt Bay Offshore Wind at Collinsville

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
1	PG&E Mosslanding-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	123,292	1,831	123,292	1,831
2	PG&E Collinsville-Pittsburg 230 kV	COLLNSVL-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	122,556	2,996	0	0	122,556	2,996
3	Path 46 WOR	P46 West of Colorado River (WOR)	88,209	280	0	0	88,209	280
4	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	78,763	4,220	0	0	78,763	4,220
5	SCE W.LA	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	64,403	1,075	64,403	1,075
6	COI Corridor	P66 COI	63,366	655	0	0	63,366	655
7	PG&E Fresno	GWF_HEP-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	59,338	1,599	0	0	59,338	1,599
8	SCE EOL	LUGO-VICTORVL 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV	0	0	55,553	110	55,553	110
9	GridLiance/VEA	INNOVATION-DESERT VIEW 230 kV line #1	48,730	2,700	0	0	48,730	2,700
10	SCE NOL	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	40,893	2,353	40,893	2,353
11	SCE EOL	P61 Lugo-Victorville 500 kV Line	29,358	8	1,354	354	30,711	362
12	PG&E Panoche/Oro Loma area	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	27,604	1,541	238	315	27,842	1,856
13	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	27,755	801	0	0	27,755	801
14	SCE NOL	VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	27,498	2,221	27,498	2,221
15	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	25,758	558	25,758	558
16	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	21,707	1,557	21,707	1,557
17	SCE W.LA	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	20,408	333	20,408	333
18	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	20,363	3,027	0	0	20,363	3,027

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
19	GridLiance/VEA	AMARGOSA-SANDY 138 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	0	0	19,195	1,740	19,195	1,740
20	PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line #1	17,025	479	0	0	17,025	479
21	SCE Vincent	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	14,318	495	0	0	14,318	495
22	PG&E Fresno	JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	14,050	97	14,050	97
23	Path 15 Corridor	P15 Midway-LosBanos	13,549	500	0	0	13,549	500
24	SCE NOL	KRAMER-VICTOR 230 kV line #1	12,442	1,521	0	0	12,442	1,521
25	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	10,902	680	0	0	10,902	680
26	SDGE San Diego Southern	SUNCREST-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	10,276	181	0	0	10,276	181
27	Path 26 Corridor	P26 Northern-Southern California	1,236	247	8,067	501	9,303	748
28	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 SX-PQ 230 kV	0	0	9,297	15	9,297	15
29	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	8,469	531	8,469	531
30	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	8,398	632	8,398	632
31	PG&E Collinsville-Pittsburg 230 kV	PITSBG F-PITSBG E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-E 230kV	8,357	1,435	0	0	8,357	1,435
32	SDGE/CFE	P45 SDG&E-CFE	3,767	578	3,891	142	7,658	720
33	SDGE San Diego Southern	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	0	0	6,491	7	6,491	7
34	SCE E.LA	CHINO-MIRALOME 230 kV line, subject to SCE N-2 MiraLomaW-Chino #1 and #2 230kV	0	0	6,377	128	6,377	128
35	SCE NOL	VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	1	9	6,192	1,862	6,192	1,871
36	SCE Vincent	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	5,498	231	5,498	231
37	SCE NOL	KRAMER-VICTOR 230 kV line #2	5,343	699	0	0	5,343	699
38	SCE Eastern	RP_PALOVRDE-PALOVRDE 500 kV line #1	0	1	5,268	5	5,268	6
39	SCE W.LA	MESACALS-LAGUBELL 230 kV line #2	4,648	361	0	0	4,648	361
40	SDGE/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	4,550	663	4,550	663
41	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	4,278	30	4,278	30
42	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	3,901	1,476	0	0	3,901	1,476
43	SCE NOL	ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	3,646	728	3,646	728
44	SCE NOL	P60 Inyo-Control 115 kV Tie	570	563	2,900	1,126	3,470	1,689
45	PG&E Sierra	P24 PG&E-Sierra	0	0	3,315	388	3,315	388

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
46	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	3,201	79	0	0	3,201	79
47	Path 15 Corridor	LB_GT_11-GATES 500 kV line #1	0	0	2,990	68	2,990	68
48	SDGE San Diego Southern	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	2,848	122	2,848	122
49	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	2,837	418	2,837	418
50	PDCI	P65 Pacific DC Intertie (PDCI)	1,192	11	1,566	193	2,758	204
51	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	2,752	86	0	0	2,752	86
52	Path 41 Sylmar transformer	P41 Sylmar to SCE	2,419	58	0	0	2,419	58
53	GridLiance/VEA	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	2,382	1,270	1	1	2,383	1,271
54	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	2,377	6	0	0	2,377	6
55	PG&E Tesla-Los Banos 500 kV	TESLA-LOSBANOS 500 kV line #1	0	0	1,949	61	1,949	61
56	SDGE San Diego Northern	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	34	6	1,585	167	1,619	173
57	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	1,519	292	1,519	292
58	PG&E Panoche/Oro Loma area	POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,268	36	0	0	1,268	36
59	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	1,193	299	0	0	1,193	299
60	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line #1	0	0	1,152	31	1,152	31
61	SDGE/CFE	IV PFC1 230/230 kV transformer #1	1,151	144	0	0	1,151	144
62	PG&E North Valley	POE-RIO OSO 230 kV line #1	1,112	154	0	0	1,112	154
63	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	1,110	9	1,110	9
64	SCE NOL	CALCITE-LUGO 230 kV line #1	998	1,594	0	0	998	1,594
65	SCE Vincent-MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	987	3	0	0	987	3
66	COI Corridor	TABLE MTN-TM_TS_11 500 kV line #1	868	28	0	0	868	28
67	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	856	48	0	0	856	48
68	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	1	3	799	112	800	115
69	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	744	135	0	0	744	135
70	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	552	517	552	517
71	PG&E Fresno	PANOCHE-GATES E 230 kV line, subject to PG&E FRESNO N-2 GATES-MUSTANG SW STA 230kV	0	0	474	170	474	170
72	SCE E.LA	ALBERHIL-VALLEYSC 500 kV line #1	0	0	459	36	459	36

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
73	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #1	0	0	447	68	447	68
74	SDGE San Diego Southern	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	441	1	0	0	441	1
75	SCE W.LA	BARRE-VILLA PK 230 kV line, subject to SCE N-1 Lewis-Barre 230kV	0	0	417	18	417	18
76	PG&E Collinsville-Pittsburg 230 kV	E. SHORE-PITSBG E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	415	29	415	29
77	SDGE San Diego Southern	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	402	1	0	0	402	1
78	SCE Tehachapi	WLDRNESS TAP-WINDSTAR1 230 kV line #1	401	319	0	0	401	319
79	PG&E North Valley	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	379	72	379	72
80	GridLiance/VEA	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DeservtView 230 kV with RAS	365	24	0	0	365	24
81	PG&E Fresno	WARNERVL-WILSONRCTR 230 kV line #1	354	21	0	0	354	21
82	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	345	68	0	0	345	68
83	SDGE San Diego Northern	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	339	68	0	0	339	68
84	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	335	45	0	0	335	45
85	PG&E Panoche/Oro Loma area	LE GRAND-WILSONPGAE 115 kV line #1	318	71	0	0	318	71
86	PG&E Kern 230kV	WND GPJ1-WHEELER 230 kV line #1	0	0	308	178	308	178
87	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	246	56	246	56
88	PG&E Quinto-Los Banos 230 kV	QUINTO_SS-LOSBANOS 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	0	0	240	6	240	6
89	COI Corridor	TM_TS_12-TESLA 500 kV line #1	236	9	0	0	236	9
90	SDGE San Diego Northern	TALEGA-S.ONOFRE 230 kV line #1	0	0	224	62	224	62
91	SDGE/CFE	IV PFC1 230/230 kV transformer #2	205	42	0	0	205	42
92	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	162	22	162	22
93	Path 42 Corridor	DEVERS-MIRAGE 230 kV line #2	0	0	153	23	153	23
94	SCE Vincent-MiraLoma 500kV	EAST TS-MIRALOMA 500 kV line #1	0	0	152	9	152	9
95	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	145	18	0	0	145	18
96	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	142	13	0	0	142	13
97	SCE Pardee 230 kV	PARDEE-VINCENT 230 kV line #2	0	0	137	14	137	14
98	SCE Eastern	DVRS_RB_12-REDBLUFF 500 kV line #1	0	0	134	2	134	2
99	PG&E Fresno	PANOCHE1-KAMM 115 kV line #1	0	0	126	210	126	210

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
100	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	124	6	124	6
101	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	114	3	114	3
102	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	98	25	6	4	104	29
103	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	103	25	103	25
104	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	101	6	0	0	101	6
105	PG&E Panoche/Oro Loma area	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	85	113	85	113
106	PG&E Fresno	WILSONRCTR-WILSONPGAE 230 kV line #BP	69	5	0	0	69	5
107	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	58	6	58	6
108	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	57	2	57	2
109	SCE Vincent-MiraLoma 500kV	WEST TS-EAST TS 500 kV line #1	0	0	54	5	54	5
110	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	50	25	0	0	50	25
111	SCE Vincent-MiraLoma 500kV	MESA CAL-WEST TS 500 kV line #1	0	0	44	4	44	4
112	PG&E Collinsville-Pittsburg 230 kV	SANMATEO-PITSBG E 230 kV line #1	0	0	38	1	38	1
113	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	37	68	37	68
114	SCE Pardee 230 kV	ANTELOPE-PARDEE 230 kV line #1	26	3	0	0	26	3
115	COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	25	1	0	0	25	1
116	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	21	5	0	0	21	5
117	PG&E Fresno	SLATE-MUSTANG3N4 230 kV line #1	18	2	0	0	18	2
118	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line #1	13	3	0	0	13	3
119	PG&E Tesla-Metcalf 500 kV	TESLA-METCALF 500 kV line #1	12	1	0	0	12	1
120	PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	9	300	0	0	9	300
121	SCE EOL	HAE SVC-HAE SVCL 500 kV line #1	8	1	0	0	8	1
122	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	8	1	0	0	8	1
123	PG&E Central Cost	MORROBAY-SOLARSS 230 kV line #2	0	0	7	2	7	2
124	PG&E GBA	BUENAVJ2-BITTERWATRSS 230 kV line #2	0	0	7	16	7	16
125	PG&E Humboldt	HUMBOLDT-BRDGVLLE 115 kV line #1	4	12	0	0	4	12
126	PG&E Kern 230kV	WND GPJ2-WHEELER 230 kV line #1	0	0	3	6	3	6
127	PG&E Fresno	SNJQJCT-GFFNJCT 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	3	11	0	0	3	11
128	SCE Pardee 230 kV	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	3	20	0	0	3	20

No.	Area	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
129	SCE W.LA	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	3	5	0	0	3	5
130	PG&E GBA	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	3	3	0	0	3	3
131	PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	2	8	0	0	2	8
132	PG&E Central Cost	MORROBAY-SOLARSS 230 kV line #1	0	0	2	3	2	3
133	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2	3	0	0	2	3
134	PG&E Fresno	HENTAP1-MUSTANGSS 230 kV line #1	0	0	1	1	1	1
135	PG&E Fresno	HELM-MC CALL 230 kV line, subject to PG&E N-1 Tranqlty-Helm 230kV	1	9	0	0	1	9
136	SCE NOL	VICTOR-LUGO 230 kV line #1	1	1	0	0	1	1

Table G.8-6 shows the aggregated congestion results of the Sensitivity Portfolio PCM Alternative 3 case with Humboldt Bay offshore wind at Collinsville.

Table G.8-6: Aggregated congestion in Sensitivty portfolio PCM with Humboldt Bay Offshore Wind Alternative 3 (Collinsville)

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	GridLiance/VEA	191.51	14,539
2	PG&E Collinsville-Pittsburg 230 kV	132.52	4,492
3	PG&E Mosslanding-Las Aguilas 230 kV	123.29	1,831
4	SCE NOL	100.48	12,677
5	SCE W.LA	90.02	1,810
6	SDGE San Diego Southern	88.85	1,771
7	Path 46 WOR	88.21	280
8	SCE EOL	86.27	473
9	PG&E Fresno	78.14	2,891
10	COI Corridor	64.50	693
11	PG&E Panoche/Oro Loma area	40.75	2,804
12	SCE Vincent	19.82	726
13	Path 15 Corridor	19.37	1,078
14	SCE Eastern	19.30	682
15	Path 26 Corridor	18.48	1,398
16	PG&E/TID Exchequer	17.02	479
17	SDGE/CFE	13.56	1,569
18	SCE E.LA	6.84	164
19	SCE Antelope 66kV	3.90	1,476
20	PG&E Sierra	3.31	388
21	PDCI	2.76	204
22	SCE J.Hinds-Mirage	2.75	86
23	Path 41 Sylmar transformer	2.42	58
24	SDGE San Diego Northern	2.18	303
25	PG&E Tesla-Los Banos 500 kV	1.95	61

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
26	PG&E North Valley	1.49	226
27	SCE Northern	1.29	373
28	SCE Vincent-MiraLoma 500kV	1.24	21
29	PG&E Kern 230kV	0.91	726
30	PG&E GBA	0.82	157
31	Path 42 Corridor	0.60	91
32	SCE Tehachapi	0.40	319
33	PG&E Quinto-Los Banos 230 kV	0.24	6
34	SCE Pardee 230 kV	0.17	37
35	PG&E Tesla 230 kV	0.12	6
36	Path 25 PACW-PG&E 115 kV	0.02	5
37	PG&E Tesla-Metcalf 500 kV	0.01	1
38	PG&E Central Cost	0.01	5
39	PG&E Humboldt	0.01	20

G.8.2 Curtailment results of Sensitivity Portfolio PCM

G.8.2.1 Alternative 1 curtailment results

Table G.8-7 shows the wind and solar curtailment results of the sensitivity portfolio PCM Alternative 1 with the Humboldt Bay offshore wind interconnecting at Fern Road.

Table G.8-7: Wind and solar curtailment summary in the Sensitivity portfolio PCM Alternative 1 with Humboldt Bay Offshore Wind at Fern Road

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
PG&E Fresno/Kern	35,082	5,054	40,136	12.59%
SCE Tehachapi	36,526	3,494	40,020	8.73%
SCE Eastern	24,321	3,272	27,593	11.86%
GridLiance/VEA	11,446	4,000	15,447	25.90%
PG&E Diablo OSW	14,425	672	15,097	4.45%
NM	13,725	1,219	14,944	8.16%
SCE NOL	9,435	2,264	11,700	19.35%
SDGE IV	10,823	24	10,847	0.22%
PG&E Humboldt OSW	8,251	46	8,297	0.55%
PG&E Central Valley	6,629	178	6,808	2.62%
WY	4,995	707	5,702	12.39%
SCE EOL	4,994	596	5,590	10.66%
AZ	4,214	544	4,759	11.44%
PG&E North Valley	3,870	105	3,975	2.64%
PG&E Central Coast	3,427	331	3,759	8.82%
SCE Vestal-Rector	3,226	427	3,654	11.70%
ID	2,486	255	2,741	9.30%
NW	1,686	373	2,059	18.13%
SCE Ventura	1,783	223	2,005	11.10%
SCE Antelope 66 kV	878	71	949	7.45%
PG&E GBA	379	19	398	4.73%
SCE LA Basin	305	15	320	4.66%
IID	305	4	309	1.15%
SDGE San Diego	262	0	262	0.07%
Total	**203,474**	**23,894**	**227,368**	**10.51%**

G.8.2.2 Alternative 2 curtailment results

Table G.8-8 shows the wind and solar curtailment results of the Sensitivity portfolio PCM Alternative 2 with the Humboldt Bay offshore wind interconnecting at Bay Hub.

Table G.8-8: Wind and solar curtailment summary in the Sensitivity portfolio PCM Alternative 2 with Humboldt Bay Offshore Wind at Bay Hub

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total (GWh)	Curtailment Ratio
PG&E Fresno/Kern	35,228	4,908	40,136	12.23%
SCE Tehachapi	36,474	3,547	40,020	8.86%
SCE Eastern	24,364	3,228	27,593	11.70%
GridLiance/VEA	11,461	3,986	15,447	25.81%
PG&E Diablo OSW	14,416	682	15,097	4.51%
NM	13,741	1,203	14,944	8.05%
SCE NOL	9,416	2,284	11,700	19.52%
SDGE IV	10,822	25	10,847	0.23%
PG&E Humboldt OSW	8,125	172	8,297	2.07%
PG&E Central Valley	6,642	165	6,808	2.43%
WY	4,993	709	5,702	12.43%
SCE EOL	4,987	602	5,590	10.78%
AZ	4,250	509	4,759	10.69%
PG&E North Valley	3,881	94	3,975	2.36%
PG&E Central Coast	3,430	328	3,759	8.73%
SCE Vestal-Rector	3,225	429	3,654	11.73%
ID	2,492	249	2,741	9.07%
NW	1,694	365	2,059	17.75%
SCE Ventura	1,782	223	2,005	11.14%
SCE Antelope 66 kV	878	71	949	7.45%
PG&E GBA	379	18	398	4.57%
SCE LA Basin	305	15	320	4.68%
IID	305	3	309	1.12%
SDGE San Diego	262	0	262	0.06%
Total	**203,552**	**23,816**	**227,368**	**10.47%**

G.8.2.3 Alternative 3 curtailment results

Table G.8-9 shows the wind and solar curtailment results of the Sensitivity portfolio PCM Alternative 3 with the Humboldt Bay offshore wind interconnected at Collinsville.

Table G.8-9: Wind and solar curtailment summary in the Sensitivity portfolio PCM Alternative 3 with Humboldt Bay Offshore Wind at Collinsville

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total (GWh)	Curtailment Ratio
PG&E Fresno/Kern	35,059	5,077	40,136	12.65%
SCE Tehachapi	36,629	3,392	40,020	8.47%
SCE Eastern	24,435	3,158	27,593	11.45%
GridLiance/VEA	11,445	4,002	15,447	25.91%
PG&E Diablo OSW	14,460	637	15,097	4.22%
NM	13,745	1,199	14,944	8.02%
SCE NOL	9,435	2,265	11,700	19.36%
SDGE IV	10,825	22	10,847	0.21%
PG&E Humboldt OSW	7,771	525	8,297	6.33%
PG&E Central Valley	6,650	157	6,808	2.31%
WY	4,992	710	5,702	12.45%
SCE EOL	4,997	593	5,590	10.60%
AZ	4,259	500	4,759	10.50%
PG&E North Valley	3,884	91	3,975	2.29%
PG&E Central Coast	3,435	323	3,759	8.60%
SCE Vestal-Rector	3,235	418	3,654	11.45%
ID	2,509	232	2,741	8.47%
NW	1,687	373	2,059	18.09%
SCE Ventura	1,789	216	2,005	10.75%
SCE Antelope 66 kV	879	69	949	7.29%
PG&E GBA	382	16	398	3.92%
SCE LA Basin	305	14	320	4.45%
IID	306	3	309	0.96%
SDGE San Diego	262	0	262	0.05%
Total	**203,377**	**23,991**	**227,368**	**10.55%**

G.9 Economic Planning Study Requests

G.9.1 Study request for SWIP-North project

Study request overview

LS Power Development, LLC submitted an economic study request to study congestion on the California-Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB). In addition, the study requests that the ISO study the Southwest Intertie Project – North (SWIP-North) project as an economic project.

LS Power requests the ISO to quantify financial congestion on the PACI, NOB, and COI paths in addition to the physical congestion that has been quantified over the last few planning cycles.

The Southwest Intertie Project - North (SWIP - North) project is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada). The project will provide approximately 1050 MW of bi-directional transmission capacity between Midpoint and Harry Allen.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table G.9-1.

Table G.9-1: Evaluating study request – COI congestion and SWIP-North project

Study Request: COI congestion and SWIP-North project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Request is for ISO to study congestion on California Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB)	Economic studies performed by the ISO have identified congestion on COI. SWIP North project can help to reduce COI congestion.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Request refers to the wind resources at/near Midpoint consistent with the potential OOS wind identified in the CPUC's Base Case Portfolio	The ISO's transmission planning studies use CPUC's assumption for out-of-state resources
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Capacity Benefits, Renewable curtailment reduction benefits and diversity benefit	Capacity benefit from facilitating the access to out-of-state renewable resources needs to be assessed by the CPUC in the IRP portfolio development. Renewable curtailment and diversity benefit has been captured in production cost simulation study

Conclusion

The SWIP North project was studied as a transmission upgrade alternative for Idaho out-of-state wind scenario in this planning cycle, as set out in Section G.10.5.

G.9.2 Study request for NGIV2 project

Study request overview

The 85 mile long North Gila – Imperial Valley #2 Project is a new 500 kV line generally paralleling the existing North Gila – Imperial Valley #1 500 kV line (also known as the Southwest Power Link, or "SWPL"). The Project Sponsors propose the following project facility additions. The last three facilities to be owned and operated by the IID:

- A new 500 kV termination at the existing CAISO North Gila 500 kV Substation (operated by APS).
- A new 85-mile, 500 kV line between the North Gila 500 kV Substation to the Imperial Valley 500kV Substation. While the IID is proposing to be a 20% owner in this line, the remaining 80% is to be owned and costs recovered by a CAISO PTO.

- A new 500 kV termination at the existing CAISO Imperial Valley 500KV Substation (operated by SDGE).
- Contingent Facilities: Series compensation located at a proposed intermediate substation (known as Dunes), located approximately 56 miles west from North Gila, the location is electrically near the IID Highline 230 kV Substation. Note that the existing North Gila – Imperial Valley #1 line includes 50% series compensation, but is currently operated bypassed. The cost of these contingent facilities are included in the cost of the NGIV2 Project.
- A new 500 kV termination at the 500 kV Dunes Substation (initially only a contingent series compensation station) for the termination of a 1120 MVA 500/230 kV transformer.
- New Dunes 230 kV Switching Station.
- A new 6.6-mile, 230 kV segment from the 230 kV Dunes Switching Station terminating into IID's existing 230 kV Highline Substation. IID will Own 100% and operate the Dunes 500/230 kV transformer and the 230 kV transmission line between Dunes and Highline substations.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table G.9-2.

Table G.9-2: Evaluating study request – North Gila Imperial Valley #2

Study Request: North Gila Imperial Valley #2		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	The project is expected to reduce congestion on the existing Southwest Power Link (SWPL).	There is no congestion identified in this planning cycle on the North Gila – Imperial Valley 500 kV line. However, the NGIV2 project can help to mitigate congestion on Path 46.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project will provide a new delivery point at the proposed Dunes 500/230 kV substation.	A new delivery point may not help to increase the deliverability of new generators, depending on the location of the binding constraints in the system. For this specific area, the constraints are in the downstream system of the submitted project.
Local Capacity Area Resource requirements	The project will reduce LCR for the San Diego/Imperial Valley area	The ISO's 2018-2019 TPP has identified LCR reduction benefit of the submitted benefit.
Increase in Identified Congestion	Not addressed in submission	See "Identified Congestion" above
Integrate New Generation Resources or Loads	The project can increase diversity of the interregional energy resource zones	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	The project can make efficient use of existing available transmission corridors; provide additional capacity benefit under normal and emergency conditions for the southern portion of the CAISO system	The project can help to mitigate potential issues under North Gila – Imperial Valley N-1 contingency. The economic assessment in previous planning cycles demonstrated that the project would worsen the overload concerns identified in the San Diego import transmission and local 230 kV systems. This could potentially trigger reliability issues that need to be eliminated through additional capital investment.

Conclusion

The NGIV2 project is identified as a required component of a policy upgrade in southern California in this planning cycle, which is to build new transmission from N.Gila to Imperial Valley and from Imperial Valley to the SCE's Western LA Basin area. The details of the policy assessment results for the southern California transmission upgrades is set out in Chapter 3 and Appendix F.

G.9.3 Study request for PG&E Fresno Avenal area congestion

Study request overview

Transmission congestion in the Fresno Avenal area, specifically Gates-Tulare Lake 70 kV line, the Gates Substation, and the Kettleman Hills Tap to Gates 70 kV line, prevents low cost energy from serving customers.

Evaluation

The benefits described in the submission and the ISO's evaluation of the study request is summarized in Table G.9-3.

Table G.9-3: Evaluating study request – Fresno Avenal area congestion

Study Request: Fresno Avenal area congestion		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	A cost effective solution that would mitigate congestion in the Fresno Avenal area can reduce consumer costs	Congestion on the Kettleman Hills Tap-Gates 70 kV line, which is a section of Gates-Tulare Lake 70 kV line, was observed in about 450 hours over the year with $0.044 million annual congestion cost in the Base portfolio PCM in this planning cycle.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	Not addressed in submission	No benefits identified by ISO

Conclusion

Congestion in the PG&E's Fresno Avenal area was studied in the 2019-2020 TPP cycle. No economic justification for transmission upgrade to mitigate the congestion was identified in that planning cycle. The congestion in this area reduced in the current planning cycle compared with the results in the previous cycle. Therefore, no further assessment was conducted for this economic study request in this planning cycle.

G.9.4 Study request for SCE Inyokern 230 kV Upgrade Project

Study request overview

SCE submitted the Inyokern 230 kV Upgrade Project with the following scope:

- A new Inyokern 230 kV switchrack connection to the existing 115 kV with one or two 230/115 kV transformer banks.
- Loop-in of the existing BLM West-Kramer 230 kV transmission line into the new Inyokern 230 kV switchrack creating the new Inyokern-Kramer No. 1 and BLM West-Inyokern 230 kV transmission lines.
- Disconnect Randsburg 115 kV line segment of the existing Inyokern-Kramer-Randsburg No. 3 115 kV transmission line and increase operating voltage to 230 kV creating the new Inyokern-Kramer No. 2 230 kV transmission line. The construction of the existing Inyokern-Kramer-Randsburg No.3 115 kV transmission line can accommodate 230 kV so the only added scope is at the terminations.
- Operate Inyokern-Kramer-Randsburg No. 1 115 kV transmission line and either maintain as-is or loop into Randsburg

Evaluation

The benefits described in the submission and the ISO's evaluation of the economic study request are summarized in Table G.9-4.

Table G.9-4: Evaluating study request – SCE Inyokern 230 kV Upgrade Project

Study Request: SCE Inyokern 230 kV Upgrade Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	No congestion was identified in the Inyokern area in this planning cycle.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project mitigates south of Kramer, Inyokern to Kramer, and Victor area constraints for potential increase in deliverability into the area from renewables, including in-state geothermal resources.	Without downstream upgrades, there would be minimal benefits, if any.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by ISO
Other	Not addressed in submission	No benefits identified by ISO

Conclusion

No further assessment was conducted for this economic study request in this planning cycle.

G.9.5 Study request for Pacific Transmission Expansion (PTE) project

Study request overview

Western Grid Development LLC (Western Grid) submitted the PTE project, which consists of a 2,000 MW controllable HVDC subsea-transmission cable that connects Northern and Southern California via submarine cables to be located in the Pacific Ocean off the coast of California. The project was previously submitted as an economic study request and was resubmitted with a modified study scope to the Reliability Request Window of the ISO 2021-2022 transmission planning process. The project, as proposed, will have one northern point of interconnection in the PG&E area and three points of interconnection in the SCE area for its southern terminals. The proposed project includes the Voltage Source Converter (VSC) stations as in the following:

- One 2,000 MW, 500 kV DC/500 kV AC converter station located at the northern terminus of the project at Diablo Canyon 500 kV switchyard;
- One 500 MW, 500 kV DC/220 kV AC converter station connected to SCE Goleta substation via a 3 mile underground AC cable;
- One 1,000 MW, 500 kV DC/220 kV AC converter station connected at El Segundo 230 kV substation; and
- One 500 MW, 500 kV DC/220 kV AC converter station connected at Huntington Beach.

The project is proposed to have a total transfer capacity of 2,000 MW from the PG&E area into the SCE/SDG&E area or vice versa.

Evaluation

The benefits described in the submission and the ISO's evaluation of the economic study request are summarized in Table G.9-5.

Table G.9-5: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	The PTE project can create a path parallel to Path 26, which potentially helps to mitigate the congestion on Path 26.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Western Grid states that the proposed project's location off shore offers California an option to interconnect and deliver up to 2,000 MW of offshore wind energy as well as support delivery of renewable energy between northern and southern California.	No benefits identified by ISO
Local Capacity Area Resource requirements	Western Grid states that the proposed project would reduce local capacity requirements in the Western LA Basin thereby allowing 1,993 MWs of gas plant generating capacity to retire.	LCR reduction study for the Western LA Basin and SDG&E areas were conducted in the 2020-2021 planning cycle
Increase in Identified Congestion	Not addressed in submission	Congestion in the Western LA Basin and Ventura areas and on the Path 26 and Path 15 corridor can be impacted by the PTE project.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by ISO

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Other	Western Grid states the following benefits of the proposed project: • The faster response for AC voltage control and frequency stabilization while providing effective short circuit capacity and system damping requirements. • Project can deliver system flexibility to the locally constrained area. • Project reduces the risk of wildfire cutting off electric service to the LA coastal area.	No benefits identified by ISO

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 in this planning cycle, as set out in Section G.10.1.

G.9.6 Study request for Moss Landing – Las Aguilas 230 kV line congestion mitigation

Study request overview

Vistra requests the ISO review the scope of the 10 Ohms series reactor project in the 2021-2022 Transmission Plan to determine whether the scope of the approved project is sufficient to resolve the expected increase in congestion. Specifically, Vistra requests the ISO to conduct an economic study of a transmission project to reconductoring the Moss Landing – Las Aguilas 230 kV line to increase the line rating to 800 MVA.

Evaluation

The benefits described in the submission and the ISO's evaluation of the economic study request are summarized in Table G.9-6.

Table G.9-6: Evaluating study request – Moss Landing – Las Aguilas 230 kV line congestion mitigation in PG&E area

Study Request: Moss Landing –Las Aguilas 230 kV line congestion mitigation		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Vistra requested to study the benefit of mitigating the transmission congestion of the Moss Landing – Las Aguilas 230 kV line in the PG&E area	The series reactor, which was approved in the 2021-2022 cycle, can effectively reduce flow on the Moss Landing – Las Aguilas 230 kV line. Congestion was still observed on this 230 kV line in the Base Portfolio PCM under the Moss Landing – Los Banos 500 kV N-1 contingency, because the solar generation in the PG&E Fresno area increases or the Greater Bay area load increased compared with the solar generation and load in the last planning cycle. The congestion was aggravated in the Sensitivity Portfolio PCM. SPS of tripping PG&E's Fresno area solar generators can further reduce the congestion, and can be used as additional interim solution if needed.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Vistra stated that mitigating the congestion would have capacity benefit in local capacity requirements in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Vistra stated that mitigating the congestion would help to reduce renewable curtailment	The congestion was observed when the flow was from Las Aguilas to Moss Landing. PG&E Fresno area renewable and Greater Bay area load contributed to this congestion.
Other	None	No benefits identified by ISO

Conclusion

The series reactor project approved in the 2021-2022 planning cycle was effective to reduce flow on the Moss Landing-Las Aguilas 230 kV line. Congestion on this 230 kV line under the Mosslanding-Los Banos 500 kV line N-1 contingency was still observed in the base portfolio PCM and further aggravated in the sensitivity portfolio PCM, as PG&E Fresno area solar generation increases or the Greater Bay area load increases. RAS tripping solar generation in the PG&E's Fresno area can help to mitigate the congestion. Long term solution to address the Moss Landing – Las Aguilas 230 kV line congestion will still be needed as the PG&E Fresno solar generation and Greater Bay area load continue to increase. However, further clarity on the solar resource, battery, and load assumptions in these two areas will be needed to conduct comprehensive assessment for long term solution. No detailed assessment was conducted for this economic study request in this planning cycle, but the ISO will continue to monitor and assess congestion on this 230 kV line in future planning cycle.

G.9.7 Study request for GLW 500 kV Upgrade Project

Study request overview

GLW requests that the CAISO conduct economic study of the GLW 500 kV Upgrade Project, which expands on the GLW Upgrade approved in the 2021-2022 planning cycle with the following:

- Replace the 230 kV from Trout Canyon to Sloan Canyon with double circuit 500 kV lines;
- Include two 500/230 kV transformers at each Trout Canyon and Sloan Canyon station;
- Add a second 500 kV circuit from Sloan Canyon to Eldorado

Evaluation

The benefits described in the submission and the ISO's evaluation of the study request are summarized in Table G.9-7.

Table G.9-7: Evaluating study request – GLW 500 kV Upgrade Project

Study Request: GLW 500 kV Upgrade Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	GridLiance West stated that the GLW 500 kV Upgrade Project substantially reduces congestion on major facilities in the GLW system needed to transmit Southern Nevada renewables to California load centers.	Congestions were identified in the GLW 230 kV system, mainly on the Innovation-Desert View 230 kV lines under normal condition. Congestion on this line was also observed under N-2 contingency of the Trout Canyon to Sloan Canyon 230 kV lines. It is expected the proposed GLW 500 kV Upgrade project can mitigate the congestions of the Innovation – DesertView 230 kV lines under normal condition.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	GridLiance West stated the project can facilitate the increased renewable integration in the CPUC portfolio	This project was identified as a part of the policy need in the GLW/VEA area in this planning cycle.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection" above
Other	GridLiance West states that the proposed upgrades will: (1) enable ISO-connected renewable generation in Southern Nevada to meet California carbon goals (2) enhance reliability by increasing access to GLW-interconnected generation and storage capacity	No benefits identified by ISO

Conclusion

GLW/VEA area congestion was selected to receive detailed assessment in this planning cycle. The GLW 500 kV Upgrade Project was studied as an alternative to mitigate GLW/VEA congestion. This project was also identified as a policy upgrade in this planning cycle.

G.9.8 Study request for GLW Geothermal Upgrade

Study request overview

The request is to study congestion resulting from development of ISO grid-connected geothermal generation interconnected in Nevada through the GLW system. The GLW Geothermal Upgrade includes the following:

- Conversion of the VEA Beatty 138 kV substation to 500 kV and addition of two 500/24.9/14.4 kV transformers (25 MVA)
- Connect 500 MW of geothermal generation at Beatty 500 kV
- A new 500/230 kV substation at Johnnie Corner bisecting the Pahrump – Innovation 230 kV line
- Conversion of the existing 138 kV line from Beatty – Lathrop Wells – Valley Switch – Johnnie Corner to 500 kV
- Tie in NVE's Amargosa Sub (Greenlink West) to a new 500 kV station on the converted 500 kV line between Beatty and Lathrop Wells
- Add single 500/138 kV transformers at Lathrop Wells and Valley Switch stations
- Add a phase shifting transformer at Lathrop Wells 138 kV

Evaluation

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

Table G.9-8: Evaluating study request – GLW Geothermal Upgrade

Study Request: GLW Geothermal Upgrade		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	GLW Geothermal Upgrade provides additional reliability benefits by providing a path for congested deliveries of planned resources into CAISO	Policy project was recommended in this planning cycle to build new 230 kV lines from Beatty to Pahrump that can accommodate the geothermal and other resources in the portfolios.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The GLW Geothermal Upgrade will provide for the delivery of substantial levels of incremental Nevada CAISO grid-connected geothermal capacity.	Policy upgrade was recommended in this planning cycle to build new 230 kV lines from Beatty to Pahrump to interconnect the geothermal and other resources in the portfolios.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Capacity Benefits	No benefits identified by ISO

Conclusion

The 230 kV policy project recommended in this planning cycle in the Beatty area, as set out in Chapter 3, was found sufficient to interconnect the geothermal and other resources identified in the current resource portfolios in the Beatty area. Therefore, no further economic planning assessment was conducted for the GLW Geothermal Upgrade project in this planning cycle.

G.10 Detailed Investigation of Congestion and Economic Benefit Assessment

G.10.1 Path 26 corridor congestion

Congestion analysis

The production cost simulation results demonstrated congestion occurring on the Path 26 corridor mainly when the flow was from south to north. Renewable generators in the Southern California area identified in the CPUC renewable portfolio were the main driver 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 Path 26 corridor when the flow was from north to south was observed in more hours in this planning cycle than in the previous planning cycles, attributed to the increase of renewable generation in the PG&E area in the CPUC renewable portfolio, including offshore wind generators. The congestion cost and hours of the Path 26 corridor congestion are shown in Table G.10-1. It was observed that the majority of the Path 26 corridor congestion was as a result of the Path 26 path rating binding and the Midway to Whirlwind 500 kV line congestion under normal condition. The 1503 MVA normal rating was applied for this 500 kV line in order to achieve higher emergency rating. This is one of the reasons that this line is congested under normal condition in more hours than the other Path 26 lines. Another reason is that there is a large volume of renewable and battery generators modeled at Whirlwind and Windhub 500 kV buses as identified in the CPUC portfolio.

Table G.10-1: Path 26 corridor congestion

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
P26 Northern-Southern California	21	13	33,792	1,254	33,813	1,267
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	13,213	610	13,213	610
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	136	3	149	15	285	18
MW_VINCNT_12-VINCENT 500 kV line #1	7	1	0	0	7	1

Table G.10-2 shows the occurrences of the Midway – Whirlwind 500 kV line congestion. It was observed that congestion on this line not only happened in the daytime, but also in the evening hours.

Table G.10-2: Occurrences of Midway – Whirlwind 500 kV Line Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	3	5	5	1	1	2	3	4	1	1	1	1	1	1	1	1
Feb	0	0	0	0	0	0	0	0	6	6	5	5	3	3	4	2	2	2	3	6	3	3	3	3
Mar	0	0	0	0	0	0	0	11	11	10	7	7	4	8	7	6	5	1	2	3	4	3	4	2
Apr	0	0	0	0	0	0	2	10	10	3	2	2	1	2	3	2	2	0	1	3	0	0	0	0
May	0	0	0	0	0	0	1	2	1	1	1	1	0	1	0	0	0	0	0	3	0	2	0	0
Jun	0	0	0	0	0	0	2	3	2	3	0	0	0	0	2	3	3	4	4	5	7	9	10	10
Jul	0	0	0	0	0	0	0	3	1	0	1	0	2	2	2	4	2	1	0	1	1	1	1	1
Aug	0	0	0	0	0	0	2	9	10	8	5	3	1	1	2	2	3	0	0	1	0	0	0	0
Sep	0	0	0	0	0	0	0	6	8	12	8	6	7	7	6	5	0	0	0	0	1	0	1	0
Oct	0	0	0	0	0	0	0	2	12	13	9	5	3	3	4	2	0	0	0	1	3	2	2	2
Nov	0	0	0	0	0	0	0	4	7	9	6	5	3	4	7	4	1	2	2	2	2	2	1	1
Dec	0	0	0	0	0	0	0	0	4	7	7	3	3	3	4	3	1	1	0	0	1	1	1	0

Table G.10-3 shows the occurrences of the Path 26 congestion. Similarly, Path 26 congestion was observed in solar hours and in evening time. Also, Path 26 was less congested in the summer months than in other months of the year, which was mainly because the Midway – Whirlwind 500 kV line was the limiting constraints in many hours during the summer months. High southern California load in the summer months also helped to reduce flow on Path 26.

Table G.10-3: Occurrences of Path 26 Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	1	2	4	0	0	0	0	11	23	23	24	22	18	19	19	9	1	5	5	6	3	4	4	4
Feb	0	2	1	1	0	0	0	9	16	10	10	9	5	6	5	7	6	3	7	4	3	3	2	2
Mar	2	2	2	2	0	0	2	14	13	12	11	9	9	10	9	9	5	3	10	7	6	5	3	3
Apr	1	0	0	0	0	0	2	9	6	7	7	5	3	3	1	1	1	0	0	2	0	0	0	0
May	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	1	0	0	0	4	0	0	1	0
Jun	0	1	0	0	0	0	4	0	0	0	2	2	3	2	2	1	0	1	2	2	0	1	1	1
Jul	0	0	0	0	0	1	4	3	0	0	0	1	1	0	1	0	0	0	0	0	0	0	0	0
Aug	0	1	1	0	0	0	9	7	3	1	1	0	0	0	0	0	0	0	1	0	0	1	0	3
Sep	1	0	2	0	0	0	19	13	8	4	5	6	3	2	1	0	0	2	5	3	3	2	6	4
Oct	1	3	5	1	0	1	12	22	13	10	4	4	3	1	2	0	1	5	3	3	4	3	5	4
Nov	2	8	9	3	0	0	1	25	24	26	24	22	18	18	17	5	9	10	9	6	7	6	7	6
Dec	4	4	4	4	2	0	0	19	23	25	22	15	13	11	10	6	2	4	8	9	8	8	9	9

Midway – Whirlwind and Path 26 congestion was also observed outside of solar hours. Further analysis demonstrated that the congestion outside solar hours were highly correlated with battery discharge in southern California areas. Table G.10-4 shows the pattern of battery charge and discharge in the SCE area. It was observed that the batteries charged mainly in solar production hours and discharged after sunset. It should be noted that the battery charge and discharge pattern shown in Table G.10-4 was the results of economic dispatch in the production cost simulation.

Table G.10-4: SCE Battery Charge and Discharge Pattern

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	1	0	0	0	0	0	-322	-1,452	-2,081	-2,172	-2,248	-2,216	-1,795	-808	375	1,539	2,017	2,091	1,728	1,172	1,222	985
Feb	19	21	18	8	12	17	28	-3	-1,686	-4,118	-4,996	-5,630	-6,079	-6,381	-6,274	-4,511	10	3,954	5,510	6,173	5,890	4,353	4,238	3,456
Mar	24	6	2	1	3	42	18	-401	-2,117	-3,469	-4,869	-5,617	-5,850	-5,870	-5,151	-3,665	-1,176	2,132	5,276	6,103	5,962	5,405	4,006	3,477
Apr	331	186	213	171	211	183	-4	-1,365	-3,188	-4,752	-6,012	-6,748	-7,175	-7,123	-6,434	-5,223	-2,927	566	6,454	7,786	7,776	8,327	5,637	5,458
May	424	277	224	226	221	30	-564	-2,757	-3,981	-5,407	-6,308	-6,841	-7,339	-6,739	-5,967	-4,311	-1,868	207	5,926	8,461	7,804	9,037	5,907	5,520
Jun	143	64	48	15	64	34	-622	-3,369	-5,309	-6,647	-7,608	-7,828	-7,260	-5,679	-4,180	-2,413	-908	344	6,044	8,602	8,114	9,078	6,185	5,308
Jul	52	23	7	6	20	25	-50	-1,991	-4,013	-4,890	-4,936	-4,232	-3,020	-1,830	-967	-397	147	1,794	4,712	4,680	3,360	3,117	2,063	2,342
Aug	68	13	4	2	4	56	-12	-1,210	-3,378	-4,574	-4,916	-4,450	-3,731	-2,801	-1,980	-889	-71	2,027	5,588	4,776	3,732	3,129	2,113	2,291
Sep	11	2	1	0	1	59	-4	-1,607	-4,152	-5,020	-4,956	-4,201	-3,398	-2,409	-1,409	-405	738	4,758	5,325	3,992	3,266	1,984	1,447	1,833
Oct	0	0	0	0	0	4	0	-774	-3,176	-3,943	-4,080	-3,606	-3,267	-2,976	-2,247	-807	1,278	3,336	3,731	3,857	2,818	2,119	1,815	2,186
Nov	0	0	0	0	0	0	0	-51	-2,018	-3,233	-3,399	-3,264	-3,255	-3,040	-2,318	-30	2,383	2,556	2,859	2,528	1,941	1,720	1,801	1,728
Dec	0	0	0	0	0	0	0	0	-356	-1,441	-1,604	-1,497	-1,785	-1,908	-1,504	-109	1,370	1,316	1,285	1,217	831	648	965	1,040

Congestion mitigation alternatives

Two mitigation alternatives were considered in this planning cycle for mitigating the Path 26 corridor congestion, as summarized below:

- Alternative 1 – Building a new 500 kV line between the Midway and WindHub 500 kV buses with 65% series compensation. With this new 500 kV line modeled, it was further assumed that the Path 26 path rating was not needed to be enforced in the PCM. As a replacement, a new N-2 contingency of Midway to Vincent 500 kV lines was added in the PCM. It should be noted that this N-2 contingency potentially does not meet the criteria for P7 contingency and is subject to further review. However, this contingency is currently enforced in the ISO's real time operation as a credible contingency.

- Alternative 2 - The Pacific Transmission Expansion (PTE) project, which is an economic study request with multi-terminals offshore HVDC lines between the Northern and Southern California systems.

Table G.10-5 shows the relatively significant congestion of Path 26 corridor, Path 15 corridor, and the surrounding areas, which were impacted most by the mitigation alternatives.

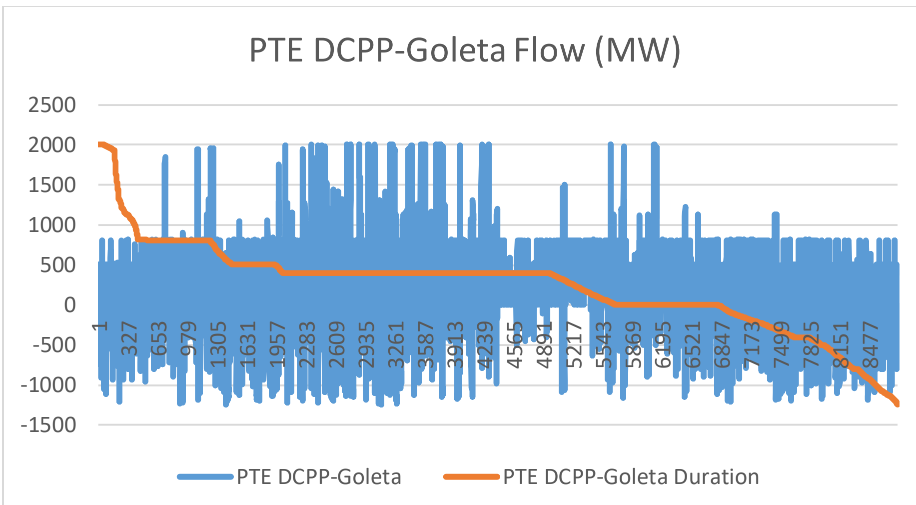
Table G.10-5: Alternatives for mitigating the Path 26 Corridor congestion

Alternative	Scope	Path 26 corridor constraints and other constraints impacted most by the mitigation	Congestion cost ($k)	Congestion Hours
A1	Midway – Windhub 500 kV line	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	14,121	504
		MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-WindHub 500 kV	334	15
		P15 Midway-LosBanos	9,651	218
		GT_MW_11-MIDWAY 500 kV line #1	4,208	222
		GATES-GT_MW_11 500 kV line #1	2,316	86
A2	PTE	P26 Northern-Southern California	20,606	2029
		MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	9,775	960
		P15 Midway-LosBanos	6,743	166
		GT_MW_11-MIDWAY 500 kV line #1	2,089	107
		LB_GT_11-GATES 500 kV line #1	1,081	35
		LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	2,084	2,238
		ISO PTE Goleta-500MW	752	2,008
		EL NIDO-LCIENEGA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	288	348
		LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	205	37

Both alternatives can help to reduce Path 26 corridor congestion compared with the base case results, but congestions on Path 26 or the individual transmission lines in this corridor still remain relatively high. Also, mitigating Path 26 corridor congestion when the flow was from south to north would allow higher flow through Path 15, which resulted in the increase of Path 15 corridor congestion. Local congestion was observed in SCE's Goleta area and El Nido area in the simulation results of the PCM case with the PTE project modeled due to the DC terminals of the PTE project increased flow injection into these areas. The PTE project can help to reduce congestion on the La Cienega – La Fresa 230 kV line in the SCE's Western LA Basin area because the PTE project essentially provides additional source to serve the Western LA Basin load.

Loop flow between the PTE HVDC lines and the Path 26 corridor was still observed in this planning cycle. Figure G.10-1 shows the DCPP – Goleta HVDC line hourly flow and duration in the PTE PCM case. The positive direction is from DCPP to Goleta. From the hourly flow results, it was observed that there were about 5700 hours when the flow on the HVDC line was from DCPP to Goleta. Consequently, the total congestion hours of the Path 26 corridor congestion increased to about 3,000 hours in the PCM case with the PTE project modeled from about 1,900 hours in the planning PCM base case, although the congestion cost reduced. There were about 1,000 hours when the Path 26 was congested in the south to north direction and the PTE flow was from DCPP to Goleta, i.e. the PTE project aggravated the Path 26 congestion in these hours. In the hours when the PTE DCPP – Goleta HVDC line flow was from south to north, it helped to mitigate the Path 26 congestion, but it aggravated congestions on the Path 15 corridor.

Figure G.10-1: PTE project Diablo – Goleta HVDC line flow



Production benefits

The production benefits of the two alternatives for the ISO's ratepayers and the production cost savings are shown in Table G.10-6.

Table G.10-6: Production Benefits of the Path 26 corridor congestion mitigation alternatives

	Base case	Path 26 A1 - Midway-Windhub 500 kV line		Path 26 A2 - PTE	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,822	18	9,827	12
ISO generator net revenue benefiting ratepayers	5,760	5,764	4	5,777	17
ISO transmission revenue benefiting ratepayers	457	437	-20	432	-25
ISO Net payment	3,623	3,621	2	3,618	5
WECC Production cost	13,937	13,921	16	13,914	23

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO generator net revenue benefiting ratepayers and an <u>increase</u> in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

Based on the production benefit calculation shown above, the annual ISO net payment saving was $2 million with the new Midway-Windhub 500 kV line modeled, and $5 million with the PTE project modeled. In the last planning cycle, the PTE project was assessed as well with both production cost benefit and LCR reduction benefit calculated. The conclusion of the last planning cycle for the PTE project was that the total benefit was less than the total cost, i.e. there was not sufficient economic benefit from this project to the ISO ratepayers. The ratepayer's production benefit, $5 million per year, went down from the last planning cycle result, which was $15 million per year. Assuming the LCR reduction benefit of the PTE project remained the same as the results in the last two planning cycles, it can conclude that there was still not sufficient economic justification for recommending the PTE project as an economic-driven project in this planning cycle.

Conclusion

There was not sufficient economic justification for recommending the two Path 26 corridor congestion mitigation alternatives as an economic-driven transmission upgrade in this planning cycle.

Path 26 corridor congestion may need to be reassessed in future planning cycles with consideration of the Path 26 path rating restudy results, and the identification of critical contingencies along the corridor and in the adjacent area.

It should be noted that that the assumptions around the value of reducing capacity requirements directly affects the value of the project. The potential PTE project benefit of reducing capacity requirements needs to be reassessed in future planning cycles as the assumptions change, particularly if the need to retain the existing gas-fired fleet for system-wide resource reliability purposes is relaxed.

G.10.2 GridLiance West/VEA congestion and mitigations

Congestion analysis

Congestion in the GridLiance West/VEA area was observed in the base portfolio PCM in this planning cycle as summarized in Table G.10-7.

Table G.10-7: GridLiance West/VEA Area Congestion in the Base Portfolio PCM

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	13,482	1,190	0	0	13,482	1,190
MEAD S-SLOAN CANYON 230 kV line #1	0	0	13,268	920	13,268	920
INNOVATION-DESERT VIEW 230 kV line #1	11,331	813	0	0	11,331	813
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	1,751	523	0	0	1,751	523
INNOVATION 138/138 kV transformer #1	420	30	0	0	420	30
GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	113	65	0	0	113	65
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DeservtView 230 kV with RAS	8	6	0	0	8	6

Congestion mitigation alternatives

The GLW 500 kV Upgrade project was assessed as the mitigation for the GridLiance West/VEA area congestion. The detailed scope of the GLW 500 kV Upgrade project was described in Section G.9.7. The simulation results showed that the GLW 500 kV Upgrade project was effective to mitigate the most of the GridLiance West/VEA area congestion, except for the Innovation – Desert View congestion under N-2 contingency of the proposed Trout Canyon - Sloan Canyon 500 kV lines. Table G.10-8 shows the congestion changes with the GLW 500 kV Upgrade project modeled.

Table G.10-8: Congestion Change with GLW 500 kV Upgrade modeled

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	21,688	1,615	0	0	21,688	1,615
INNOVATION 138/138 kV transformer #1	688	64	0	0	688	64
MEAD S-SLOAN CANYON 230 kV line #1	0	0	23	6	23	6
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	10	7	0	0	10	7

Production benefits

The production benefit for ISO ratepayers and the production-cost savings of the GLW 500 kV Upgrade project are shown in Table G.10-9.

Table G.10-9: Production Benefits of GLW 500 kV Upgrade

	Base case	GLW 500 kV Upgrade case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,841	-1
ISO generator net revenue benefiting ratepayers	5,760	5,790	30
ISO transmission revenue benefiting ratepayers	457	430	-27
ISO Net payment	3,623	3,621	1
WECC Production cost	13,937	13,924	13

Note that ISO ratepayer “savings” are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide “Savings” are a decrease in overall production cost. A negative savings is an incremental cost or loss.

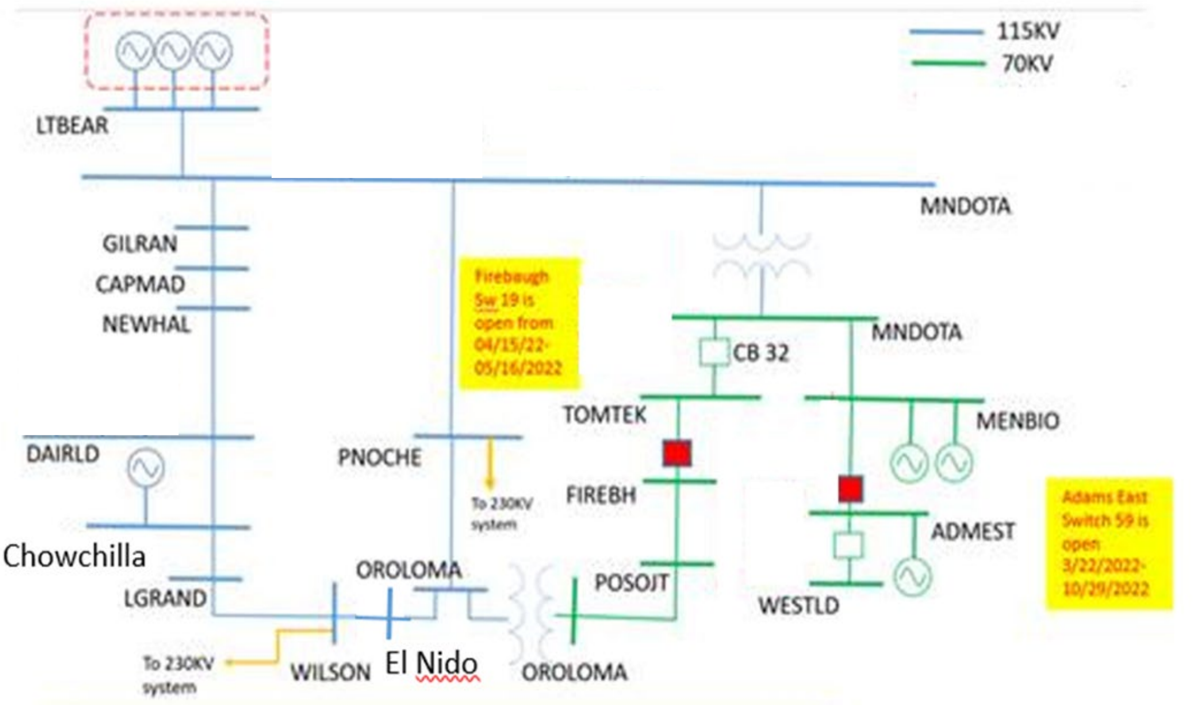
Conclusions

The GLW 500 kV Upgrade project has been identified as a recommended policy-driven upgrade in this planning cycle. Production cost simulation and economic assessment results shows that this project can help to reduce congestion in the GridLiance/VEA area, and it can create about $1 million annual ratepayer savings.

G.10.3 PG&E Panoche/Oro Loma area congestion and mitigations

Figure G.10-2 shows the one-line diagram of the Panoche/Oro Loma area 115 kV and 70 kV systems. Further investigations also identified that there are summer setups on the lines of the two 70 kV corridors in this area as shown in Figure G.10-2 . The 70 kV corridor between Oro Loma and Mendota is open between April 15 and May 16, and the other 70 kV corridor between Westland and Mendota is open between March 22 and October 29. These summer setups were developed for local system reliability and load serving. However, with these setups between March and October there is only one 70 kV corridor in service in this area, which is the Mendota to Oro Loma 70 kV lines. Loop flow between the 115 kV and 70 kV systems in this area may cause congestion on the 70 kV lines in such situations.

Figure G.10-2: Panoche/Oro Loma area diagram



Congestion analysis

Congestion in the Panoche/Oro Loma area was observed in the base portfolio PCM simulation results in this planning cycle. The congestion was on the 70 kV and 115 kV lines under N-1 contingency of the Panoche-Mendota 115 kV line, and on the Oro Loma-El Nido 115 kV line under normal condition, as summarized in Table G.10-10. The transmission congestion resulted in significant solar curtailment in the local area. The curtailment ratio in this area is about 11% in the base portfolio PCM, compared with the 2.55% system overall curtailment ratio.

Table G.10-10: PG&E Panoche/Oro Loma area congestions

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	18,026	909	1,830	510	19,856	1,419
ORO LOMA-EL NIDO 115 kV line #1	10,077	571	0	0	10,077	571
POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2,004	58	0	0	2,004	58
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	268	118	268	118
NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	33	44	0	0	33	44
ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	4	3	0	0	4	3

Table G.10-11 shows the occurrences of the Oro Loma – Poso 70 kV congestion under the Panoche – Mendota 115 kV N-1 contingency, in the hours of the day for each month, in the base portfolio PCM.

Table G.10-11: Occurrences of Oro Loma – Poso 70 kV Congestion under Panoche – Mendota 115 kV N-1 Contingency in the Base Portfolio PCM

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	1	7	7	5	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	1	2	2	2	2	2	3	2	1	0	0	0	0	0	0	0	0
May	1	0	0	0	0	0	0	0	0	7	10	13	12	11	11	5	1	0	0	4	5	5	4	1
Jun	13	3	0	0	0	0	0	0	4	16	20	25	28	27	19	10	3	0	1	17	18	19	17	10
Jul	18	1	0	0	0	0	0	0	1	16	29	29	28	18	5	1	0	0	22	28	27	25	22	19
Aug	22	13	5	2	1	0	0	1	0	0	15	25	25	15	2	1	1	0	23	27	26	25	20	19
Sep	29	28	9	3	1	0	1	1	0	2	8	19	18	10	3	0	0	15	21	23	25	24	23	21
Oct	26	16	8	4	3	0	6	0	0	0	1	4	3	1	0	0	0	7	21	24	23	22	19	13
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The main observations regarding the Oro Loma – Poso 70 kV congestion are that:

- The congestion occurred between March and October;
- The congestion occurred not only in daytime, but also in nighttime; and
- The congestion can occur when the flow was in either direction. Specifically, in the daytime, the congestion mainly occurred when the flow was from Poso to Oro Loma; while in the nighttime, the congestion mainly occurred when the flow was from Oro Loma to Poso.

The daytime congestion on the Oro Loma to Poso 115 kV line was attributed to the solar generation injecting at the Mendota 115 kV bus and the flow was from Poso to Oro Loma. The nighttime congestion on the Oro Loma to Poso 115 kV line occurred when the flow direction was from the Oro Loma 115 kV bus to the Mendota 115 kV bus through the 70 kV lines including Oro Loma to Poso. The loop flow in this direction was caused by serving local load in the 70 kV system and the Mendota 115 kV system when the solar resources were not generating in this area. Normally the local load was mainly served by the 230 kV system through the Wilson 230 kV bus and the Panoche 230 kV bus when there is no solar generation in this local area. Under the N-1 contingency of the Panoche – Mendota 115 kV line, the flow from the 230 kV sytem to the 115 kV load can only come through the Wilson 230 kV bus, which may flow through the 70 kV lines from the Oro Loma 70 kV bus to Mendota 70 kV bus and cause congestion on the 70 kV lines.

Table G.10-12 shows the occurrences of the Oro Loma – El Nido 115 kV congestion under normal condition, in the hours of the day for each month. It was observed that the Oro Loma – El Nido 115 kV congestion under normal condition occurred between April and October when the flow is from Oro Loma to El Nido. This was mainly because the summer rating of the Oro Loma – El Nido 115 kV line is lower than the winter rating. Solar generation in the 115 kV system also contributed to the congestion as the congestion mainly occurred in daytime, in the base portfolio PCM.

Table G.10-12: Occurrences of Oro Loma – El Nido 115 kV congestion under normal condition in the Base Portfolio PCM

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	6	7	5	6	3	2	2	3	1	1	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	5	3	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	4	5	5	6	6	6	7	9	14	15	14	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	1	4	8	4	3	7	13	16	16	14	5	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	13	15	13	13	9	10	10	11	8	7	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	15	17	20	18	14	14	12	12	6	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	14	23	23	13	10	5	3	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The New Hall – Diary Land and Le Grant – Chowchilla 115 kV lines were also congested under the N-1 contingency of the Panoche – Mendota 115 kV line. This congestion occurs in the daytime in April and May when there is only one 70 kV circuit breaker open due to the summer setup. The Le Grant – Chowchilla 115 kV line also has lower summer rating than the winter rating.

Congestion mitigation alternatives

It was observed from the analysis above that the congestion on the 70 kV and 115 kV lines in the Panoche/Oro Loma area were attributed to multiple factors, such as solar generation, local load, and loop flow. These factors impacted the flow and congestion in this area in different directions.

Several alternatives for mitigating the Panoche/Oro Loma area congestion, including combinations of alternatives, were assessed. Table G.10-13 shows the congestion results in the Panoche/Oro Loma area.

Table G.10-13: Alternatives for mitigating the Panoche/Oro Loma area congestion

Alternative	Scope	Panoche/Oro Loma area constraints	Congestion cost ($k)	Congestion Hours
A1	Modify the 70 kV summer setup to have both 70 kV corridor open from March to October	ORO LOMA-EL NIDO 115 kV line #1	5,754	385
		LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1	3,895	656
		NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	586	290
		CHWCHLASLRJT-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	524	4
		ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	60	15
A2	RAS tripping solar generation	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	38,201	1,702
		ORO LOMA-EL NIDO 115 kV line #1	5,290	345
		POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2,215	73
		BIOMSJCT-MENDOTA 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	115	24
		ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	76	5
A3	Reconductoring the 115 kV lines between the Oro Loma and WilsonPG&E 115 kV buses and between the Le Grand and Newhall 115 kV buses	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	19,015	1,350
		POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,735	51
A4	A1 plus A3	MENDOTA-GILLTAP 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	577	150
A5	A1 plus A2 plus A3	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	421	3
		CHWCHLASLRJT-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	376	3
		BIOMSJCT-MENDOTA 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	126	25

In the Alternative 1 case, which is to modify the 70 kV summer setup to open both 70 kV corridor from March to October, 70 kV congestion can be mitigated. However, the 115 kV congestion still occurred, especially Le Grand – Chowchilla 115 kV congestion increased. Table G.10-14 shows the occurrences of congestion on the Le Grand – Chowchilla 115 kV line under the N-1 contingency of the Panoche – Mendota 115 kV line in the Alternative 1 PCM case. It was also observed that congestion on the Le Grand – Chowchilla 115 kV line mainly happened when the flow was from Chowchilla to Le Grand and in daytime, which indicated that the solar generation in the areas between Mendota and Chowchilla are the main driver of the congestion. The Le Grand – Chowchilla 115 kV line was also congested in four evening hours in July when the flow was from Le Grand to Chowchilla, which was the flow coming from the Wilson 230 kV system to serve the local load in the 115 kV system in this area

Table G.10-14: Occurrences of Le Grand - Chowchilla 115 kV congestion under N-1 contingency in Alternative 1 case

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	7	10	11	11	12	10	2	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	15	21	24	24	25	20	1	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	2	16	18	20	21	20	16	1	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	18	27	27	29	19	4	0	0	0	0	3	1	0	0	0
Aug	0	0	0	0	0	0	0	0	0	2	23	24	24	20	4	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	4	17	23	21	19	1	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	3	15	17	4	0	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the Alternative 2 case, RAS tripping solar generation in the local area under the contingency aggravated the 70 kV congestion when the flow was from the Oro Loma 70 kV bus to the Mendota 70 kV bus. Table G.10-15 shows the occurrences of the Oro Loma – Poso 70 kV congestion under the N-1 contingency of the Panoche – Mendota 115 kV line. The congestion on this line in the Alternative 2 case was only observed when the flow was from Oro Loma to Poso. Also it was observed that in many hours the penalty price of the line was triggered, which implied that there would potentially be loss of load in this area when the RAS tripping solar generation was applied. Therefore, the RAS tripping solar generation following the N-1 contingency alone is not a feasible option to mitigate the congestion in this area.

Table G.10-15: Occurrences of Oro Loma - Poso 70 kV congestion under N-1 contingency in Alternative 2 case

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	6	11	8	6	5	2	2	1	2	3	3	0	0	0	1	1	1	0
May	1	1	0	0	0	0	8	4	4	3	2	2	2	2	2	2	4	2	1	5	4	5	2	1
Jun	9	4	0	0	0	1	16	9	5	5	5	3	2	6	11	17	17	16	15	18	18	19	17	15
Jul	20	2	0	0	0	0	6	10	6	1	0	0	1	8	19	23	25	26	28	28	28	26	25	24
Aug	23	13	6	2	1	2	13	26	20	12	6	4	6	6	11	17	21	17	24	27	25	25	22	20
Sep	29	24	12	5	1	0	23	26	19	16	10	8	2	7	13	14	13	16	23	23	24	23	21	20
Oct	28	19	11	4	3	0	11	23	28	24	16	9	10	4	6	5	0	8	23	24	24	22	19	13
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the Alternative 3 case with the reconductoring the 115 kV lines between Oro Loma and Wilson PG&E 115 kV buses, the 115 kV congestion can be mitigated, but the 70 kV congestion under the N-1 contingency of the Panoche-Mendota 115 kV line still remained.

Table G.10-16 shows the occurrences of the Oro Loma – Poso 70 kV line congestion under the Panoche – Mendota 115 kV N-1 contingency in the Alternative 3 case, which has the similar pattern as in Table G.9.3-2 that shows the occurrences of the same 70 kV line in the base portfolio PCM case.

Table G.10-16: Occurrences of Oro Loma – Poso 70 kV Congestion under Panoche – Mendota 115 kV N-1 Contingency in the Alternative 3 case

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	2	7	8	5	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	1	1	2	2	2	3	2	1	0	0	0	0	0	0	0	0
May	1	0	0	0	0	0	0	0	0	7	10	12	11	11	10	5	0	0	0	4	5	4	4	1
Jun	12	3	0	0	0	0	0	0	4	16	21	26	25	24	14	5	0	0	0	17	18	18	17	12
Jul	20	0	0	0	0	0	0	0	1	16	29	29	26	15	5	0	0	0	22	28	27	25	23	16
Aug	25	13	4	2	1	0	0	0	0	0	16	23	23	16	2	0	0	0	22	27	25	25	20	19
Sep	27	26	11	3	0	0	0	0	0	1	7	16	13	9	3	0	0	13	20	23	25	24	23	20
Oct	26	17	8	4	3	0	7	0	0	0	0	2	4	1	0	0	0	8	19	22	23	19	14	11
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the Alternative 4 case, reconductoring the 115 kV lines combined with modifying the 70 kV summer setup can effectively mitigate most of the congestion in this area. As other constraints were mitigated, the Mendota – Gill Tap 115 kV line congestion under the N-1 contingency of the Panoche – Mendota 115 kV line showed up in 149 hours with $0.583 million congestion cost per year. Table G.10-17 shows the occurrences of the Mendota – Gill Tap 115 kV line congestion under the Panoche – Mendota 115 kV N-1 contingency in the Alternative 4 case. The Mendota – Gill Tap 115 kV line has the same winter and summer ratings.

Table G.10-17: Occurrences of Mendota – Gill Tap 115 kV Congestion under Panoche – Mendota 115 kV N-1 Contingency in the Alternative 4 case

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	1	5	7	1	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	2	11	11	5	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	10	14	15	7	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	8	16	17	5	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	1	6	4	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The Alternative 5 case in this study is to add a RAS tripping solar generators following the N-1 contingency of the Panoche – Mendota 115 kV line in the Alternative 4 case. The Mendota – Gill Tap 115 kV line congestion can be mitigated by the RAS, but congestion still showed up on other 115 kV and 70 kV lines in this area.

Production benefits

The production benefits for ISO ratepayers and the production cost savings of all alternatives discussed above are summarized in Table G.10-18 .

Table G.10-18: Production Benefits of mitigation alternatives in the Panoche/Oro Loma area

	Base case	Panoche/OroLoma A1-Summer Setup		Panoche/OroLoma A3-reconductoring the 115 kV system		Panoche/OroLoma A4-A1 plus A3		Panoche/OroLoma A5 – A1 plus A2 plus A3	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,823	16	9,837	3	9,807	32	9,812	28
ISO generator net revenue benefiting ratepayers	5,760	5,755	-5	5,765	5	5,754	-6	5,757	-3
ISO transmission revenue benefiting ratepayers	457	438	-19	445	-12	425	-32	426	-31
ISO Net payment	3,623	3,630	-8	3,627	-4	3,628	-6	3,629	-6
WECC Production cost	13,937	13,938	-1	13,936	1	13,935	2	13,937	0

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

The economic assessment was not performed for the Alternative 2, the RAS alternative, because it alone is not a feasible option as discussed earlier in this section. Alternative 4, which is to reconductoring the 115 kV lines plus modifying the summer setup for the 70 kV lines, and Alternative 5, which is the Alternative 4 case with a RAS tripping the solar generation under a Panoche – Mendota 115 kV line N-1 contingency, can effectively mitigate congestion in this area, but it did not show economic benefit to ISO's ratepayers. This is because this alternative significantly reduced the congestion cost, which is deemed as transmission revenue benefiting ratepayers in TEAM calculation. As showed above, the transmission revenue reduced by $32 million, although the load payment also reduced by $31 million. In the meantime, generator profit reduced as well by $4 million, which is attributed to the LMP increase as the curtailment reduced.

Cost estimate

The estimated cost of reconductoring the 115 kV lines in the Panoche/Oro Loma area (Alternative 3) is $173 million.

The capital cost of RAS has not assessed in this planning cycle because the RAS of simply tripping solar generation in this area may not be a feasible solution as discussed in this section. In a future planning cycle, RAS may be further evaluated as a part of the overall solution for this area. The cost of RAS would be assessed based on the actual requirements including number of inputs or monitored elements, e.g. load, generators, and substations, and the communication between all elements.

Conclusions

Multiple alternatives for mitigating the congestion in the Panoche/Oro Loma area were assessed; however none of these alternatives assessed for the Panoche/Oro Loma area congestion are recommended for approval as economic-driven upgrade in this planning cycle. None of the alternatives identified clear economic benefit to the ISO's ratepayers. The ISO will continue to coordinate with PG&E to investigate feasible and cost effective solutions for mitigating the Panoche/Oro Loma area congestion in future planning cycle.

G.10.4 PG&E Fresno Henrietta 115 kV congestion

Congestion analysis

Congestion on the Fresno Henrietta 115 system was observed in the Base portfolio PCM simulation results in this planning cycle. The congestion was observed under the N-2 contingency of the Helm-McCall 230 kV line and the Henrietta Tap2 – Mustang 230 kV #1 line. Table G.10-19 provides the congestion in the Fresno Henrietta 115 kV system.

Table G.10-19: PG&E Henrietta 115 kV congestions

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
GWF_Henrietta - CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	11,614	498	0	0	11,614	498
JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	1,761	13	1,761	13

The congestion on these two lines occurred when the flow in the Henrietta 115 kV system was from the Henrietta 115 kV bus to the GWF_Henrietta 115 kV bus, and from the GWF_Henrietta 115 kV bus to the Contadina 115 kV bus, and from the Contadina 115 kV bus to the Jackson 115 kV bus. Table G.10-20 shows the occurrences of the GWF_Henrietta to Contadina 115 kV line congestion under the N-2 contingency of Helm-Mc Call and Henrietta Tap2 – Mustang 230 kV lines, for the hours of the day in each month.

Table G.10-20: Occurrences of GWF_Henrietta to Contadina 115 kV congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	9	6	10	7	5	0	2	1	0	0	1	3	1	0	0	0
Feb	0	0	0	0	0	0	0	1	9	6	3	2	2	2	2	1	3	0	2	2	0	0	0	0
Mar	0	0	0	0	0	0	0	6	4	5	5	5	4	3	3	4	1	0	1	0	0	0	0	0
Apr	0	0	0	0	0	0	5	10	10	6	4	2	2	2	2	2	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	2	1	1	1	1	1	1	1	0	0	2	1	0	0	0	0	0	0
Jun	0	0	0	0	0	1	0	0	0	1	0	0	0	0	2	4	5	4	3	5	5	5	4	2
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	8	14	9	9	9	7	3	0
Aug	0	0	0	0	0	0	2	1	0	0	0	0	1	0	0	0	2	7	8	7	5	5	4	0
Sep	0	0	0	0	0	0	3	8	8	5	5	2	1	0	2	3	1	4	10	10	8	6	4	1
Oct	0	0	0	0	0	0	1	5	15	12	8	4	2	2	1	0	0	0	0	1	0	0	0	0
Nov	0	0	0	0	0	0	0	0	3	4	1	1	0	2	1	0	0	0	1	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	5	8	5	3	2	2	0	0	0	0	1	0	0	0	0	0

There were three main observations regarding the GWF_Henrietta to Contadina 115 kV congestion:

- There were about 350 congestion hours in daytime, which is about 70% of the total congestion hours;
- Congestion on this line was observed in nighttime; and
- Congestion was observed in both winter and summer months.

The daytime congestion is an indication that solar generation in Fresno area contributes to the GWF_Henrietta to Contadina congestion. However, there was still about 30% of the total congestion hours in nighttime, which indicates that solar generation was not the only reason of the congestion. Investigating the system topology and power flow results further in the Fresno area showed that the loop flow from the Henrietta 230 kV to the Henrietta 115 kV system, especially following the N-2 contingency of Helm - McCall and Henrietta Tap2 - Mustang 230 kV lines, was one of the main drivers of the Henrietta 115 kV congestion.

The congestion observed in the months where the winter rating applied indicated that simply eliminating the congested related to the summer rating of 115 kV lines, which is lower than the winter rating, cannot completely mitigate the congestion.

Congestion mitigation alternatives

Two alternatives were identified based on the above analysis and received detailed analysis:

- Alternative 1 – Expanding the GWF_Henrietta – Contadina and Contadina – Jackson 115 kV lines to double circuit 115 kV lines; and
- Alternative 2 – SPS to open the GWF_Henrietta – Contadina 115 kV line following the N-2 contingency of the Helm – McCall and Henrietta Tap2– Mustang 230 kV lines

Both alternatives can effectively mitigate the Henrietta 115 kV congestion under the N-2 contingency of Helm-McCall and Henrietta Tap2 – Mustang 230 kV lines, without notably aggravating congestions on other transmission constraints. There was still slight congestion in about 12 hours of the year on the GWF_Henrietta – Contadina 115 kV line under normal conditions with Alternative 2 was modeled. Further investigating showed that this normal congestion occurred in early evening hours after sunset in July and September timeframe. The congestion was mainly driven by the flow injecting from the 230 kV system to serve local load in the 115 kV system. The local thermal generation injecting at the GWF_Henrietta 115 kV bus also contributes to this congestion.

Production benefits

The production benefits for ISO ratepayers and the production cost savings of the two alternatives discussed above are shown in Table G.10-21.

Table G.10-21: Production Benefits of mitigation alternatives in the Henrietta 115 kV system

	Base case	Henrietta 115 kV A1 -double circuit 115 kV		Henrietta 115 kV A2 - SPS to open 115 kV	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,776	64	9,740	99
ISO generator net revenue benefiting ratepayers	5,760	5,730	-30	5,705	-55
ISO transmission revenue benefiting ratepayers	457	435	-22	427	-30
ISO Net payment	3,623	3,611	12	3,609	14
WECC Production cost	13,937	13,942	-5	13,948	-11

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Cost Estimate

Using the per-unit cost provided by PG&E, the capital cost of the double circuit alternative is estimated to cost $160 million in 2022 dollar. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the total cost of the double circuit alternative is $208 million.

Benefit-to-cost ratio

The present values of the economic benefit of the Henrietta area GWF_Henrietta – Contadina - Jackson 115 kV double circuit alternative is shown in Table G.10-22 along with the calculation of the benefit-to-cost ratio. The project economic life of the double circuit is assumed to be 50 year. No capacity saving was identified in this planning cycle.

Table G.10-22: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of SCE North of Lugo Upgrade Alternatives

	Henrietta 115 kV A1 -double circuit 115 kV
Production cost savings ($million/year)	12
Capacity saving ($million/year)	0
Capital cost ($million)	160
Discount Rate	7%
PV of Production cost savings ($million)	177
PV of Capacity saving ($million)	0
Total benefit ($million)	177
Total cost (Revenue requirement) ($million)	208
Benefit-to-cost ratio (BCR)	0.852

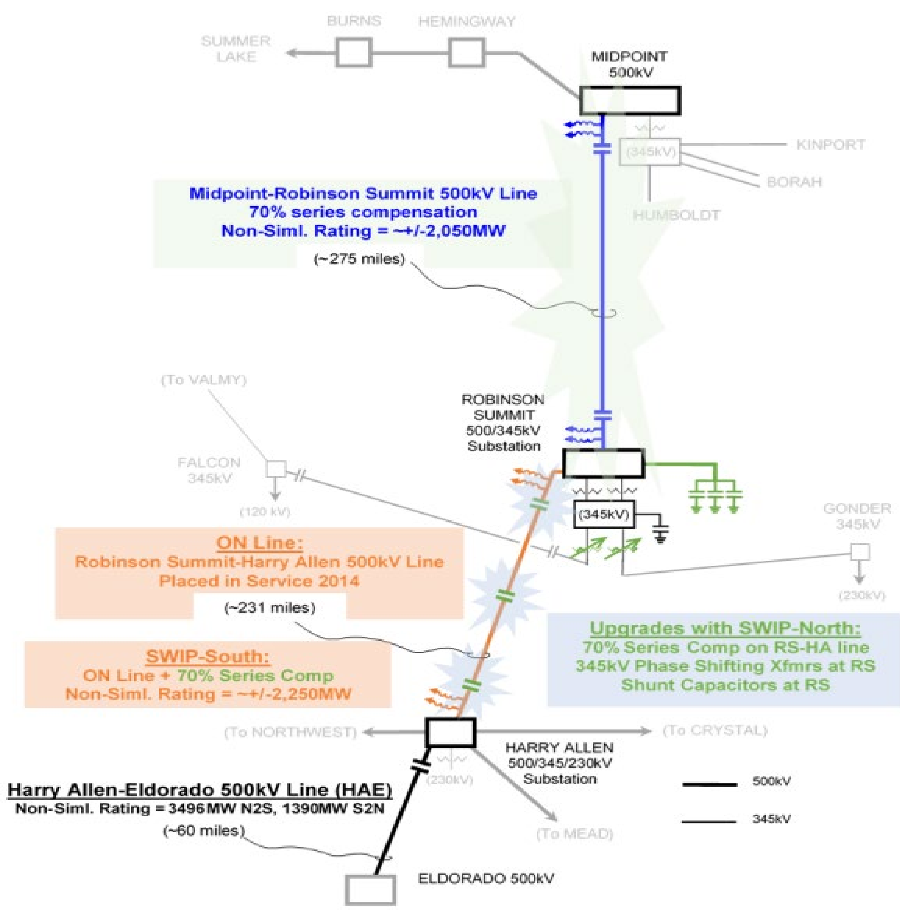
Conclusions

Two alternatives for mitigating the Henrietta area GWF_Henrietta – Contadina - Jackson 115 kV line congestion under N-2 contingency of the Helm – McCall and Henrietta Tap2 – Mustang 230 kV lines were assessed: build a double circuit 115 kV line; and a RAS to open the 115 kV line under the N-2 contingency. Both alternatives are effective to mitigate congestion. The double circuit alternative has 0.852 benefit-to-cost ratio, which indicated that the economic benefit is not sufficient to justify this alternative as an economic upgrade. The RAS alternative shows greater benefit than the double circuit alternative. The CAISO recommends PG&E to evaluate the feasibility of the RAS and its reliability implication to the local area, and consider to implement the RAS as an operational solution for the congestion in the Henrietta area. The ISO will continue to monitor and assess this area in future planning cycle if the congestion is still observed. Other mitigation alternatives may be evaluated as well in future planning cycle, for example, reconfiguring the 230 kV lines to make the N-2 contingency of the Helm – McCall and Henrietta Tap2 – Mustang 230 kV lines not a credible P7 contingency.

G.10.5 SWIP North project

The SWIP North project was submitted to the CAISO as an economic study request in this planning cycle. Figure G.10-3 shows the diagram of the SWIP North project provided by LS Power in the 2021-2022 transmission planning process economic study request.

Figure G.10-3: SWIP North Project



The SWIP North project included the new 500 kV line between the Midpoint and Robinson Summit 500 kV buses, the series compensation on the Robinson Summit – Harry Allen 500 kV line, and the 500/345 kV phase shifters at the Robinson Summit substation. In the 2021-2022 planning cycle, LS Power suggested that the path rating of SWIP South (i.e. the Robinson Summit – Harry Allen 500 kV line) can be increased from 900 (N-S)/600 (S-N) MW to 2000/2000 MW. LS Power also stated that SWIP North can provide 1100 MW of transmission right to the ISO between Midpoint and Harry Allen. Accordingly, this portion of SWIP North capacity was modeled as the ISO owned transmission capacity in the planning PCM for the SWIP North study. The same SWIP North model was used in the 2022-2023 planning cycle, with updated impedances provided by LS Power.

In the study for the SWIP North project in this planning cycle, the base portfolio PCM base case was modified to model 1062 MW of Idaho wind generator at the Midpoint 500 kV bus to replace the 1062 MW of Wyoming wind generators in the case. Accordingly, the TWE project was turned off in the SWIP North study PCM cases. The only difference between the pre and post SWIP North project cases is that the post case had the SWIP North project modeled.

Production cost simulation results

When 1062 MW of Wyoming wind was replaced with the 1062 MW of Idaho wind, the congestion results changed, as shown in Table G.10-23. It was seen that SCE EOL congestion reduced but COI congestion increased in this PCM case, which was mainly because the TWE project was turned off in the PCM with Idaho wind modeled.

Table G.10-23: Aggregated potential congestion in the ISO-controlled grid in 2032 in the Base portfolio PCM with Idaho wind modeled

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	SCE NOL	73.83	5,523
2	COI Corridor	69.59	1,438
3	GridLiance/VEA	49.83	3,849
4	Path 26 Corridor	36.63	1,786
5	PG&E Panoche/Oro Loma area	30.76	2,163
6	SDGE San Diego Southern	16.99	1,074
7	SCE W.LA	13.25	214
8	PG&E Fresno	13.11	1,012
9	PG&E Mosslanding-Las Aguilas 230 kV	7.79	398
10	SDGE/CFE	7.31	1,647
11	Path 15 Corridor	6.55	246
12	Path 46 WOR	5.11	129
13	PG&E North Valley	3.95	208
14	SCE Antelope 66kV	3.75	1,057
15	PG&E Collinsville-Pittsburg 230 kV	3.36	561
16	PDCI	1.55	93
17	SCE Eastern	0.86	23
18	SCE J.Hinds-Mirage	0.53	135
19	PG&E Sierra	0.46	160
20	PG&E GBA	0.42	80
21	PG&E Quinto-Los Banos 230 kV	0.35	9
22	PG&E Tesla-Los Banos 500 kV	0.32	7
23	SCE EOL	0.29	19
24	Path 41 Sylmar transformer	0.09	23
25	SCE Vincent-MiraLoma 500kV	0.08	2
26	SCE Vincent	0.07	5
27	Path 25 PACW-PG&E 115 kV	0.06	6
28	SCE Tehachapi	0.05	277
29	SDGE San Diego Northern	0.05	24
30	Path 42 Corridor	0.04	8
31	PG&E Humboldt	0.00	17
32	SCE Northern	0.00	9

As discussed earlier in this section, the SWIP North project was added to the base portfolio PCM with Idaho wind modeled. The major congestion changes after modeling the SWIP North project are summarized in Table G.10-24.

Table G.10-24: Congestion changes after modeling SWIP North project

Area or Branch Group	Congestion Cost ($M) without SWIP North	Congestion Cost ($M) with SWIP North	Change in Congestion Cost ($M)
COI Corridor	69.59	45.79	-23.80
SWIP South	0.00	1.93	1.93
Path 15 Corridor	6.55	8.57	2.01
Path 26 Corridor	36.63	46.05	9.42

It was observed that COI annual congestion cost reduced by $23.8 million with the SWIP North project modeled. This was because the SWIP North project together with the SWIP South line, which is the existing 500 kV line between Robinson Summit and Harry Allen, provided a parallel path to COI between the Northwest areas and California. In the meantime Path 26 annual congestion cost increased by $9.42 million, as the SWIP North and SWIP South lines increased flow injecting into the southern California area, hence aggravating Path 26 flow from south to north. Path 15 corridor congestion from south to north increased for the same reason. SWIP South congestion showed up in the PCM case with SWIP North modeled when the flow was from north to south.

To help understand the impact of the SWIP North project on the overall congestion pattern in the ISO system, further analysis on north to south and south to north flows on SWIP North was conducted.

Figure G.10-4 shows the SWIP North flow and as well as the duration curve. It was observed that the number of hours when the flow on the SWIP North line was from south to north was about the same as when the flow was from north to south.

Figure G.10-4: SWIP North Flow and Duration

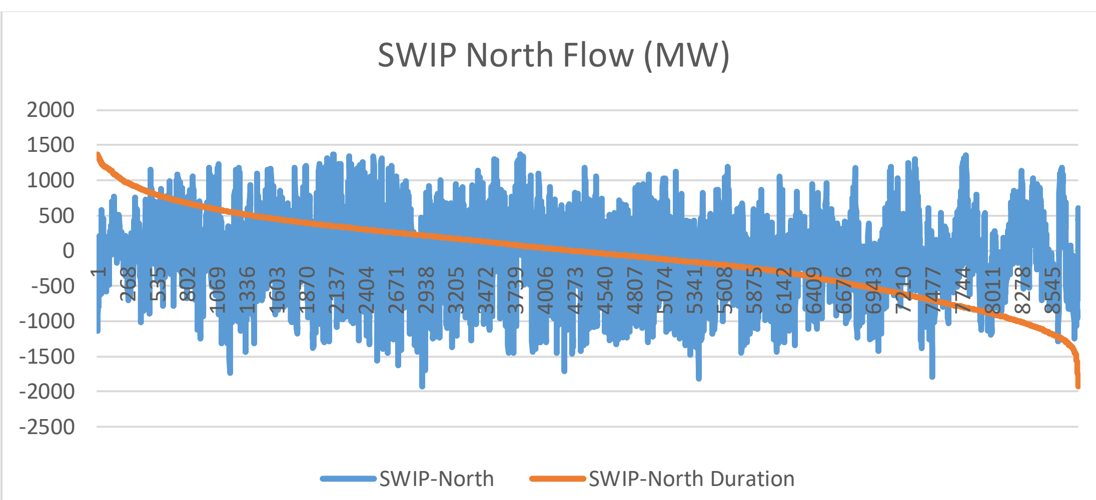


Table G.10-25 used a heat map to show the occurrence of SWIP North flow from north to south in the hours of the day for each month. The total occurrences in each month or at each hour when the flow was from north to south is also showed in the table. There were 4252 hours in the year when the SWIP North flow was from north to south, which means there were a total 4532 hours (8784 hours total in 2032) when the flow was from south to north. The heat map shows that the SWIP North flow was from north to south mainly during the nighttime. There were only limited hours in daytime when the SWIP North flow was from north to south, which means the SWIP North flow was mainly from south to north during daytime. This is consistent with the California solar generation pattern.

Table G.10-25: Occurrence of SWIP North flow from north to south

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	25	22	23	21	25	22	24	16	9	6	9	9	11	10	11	16	26	26	23	22	23	27	23	25	454
Feb	23	23	25	26	25	23	26	17	7	3	3	4	3	3	3	4	17	22	21	22	21	19	21	23	384
Mar	28	28	30	30	28	27	26	9	7	6	4	4	3	4	5	6	14	29	24	29	27	28	25	24	445
Apr	24	26	28	27	22	25	6	3	2	1	1	0	0	0	0	2	5	21	24	24	22	23	25	24	335
May	21	27	31	31	31	28	1	1	1	1	1	1	0	1	4	5	5	19	30	28	28	24	26	26	371
Jun	26	26	27	28	30	25	3	1	1	3	3	4	5	9	10	11	13	23	28	26	28	26	25	25	406
Jul	31	31	31	31	30	24	3	2	1	1	0	0	1	1	2	11	18	24	30	27	28	29	27	24	407
Aug	26	18	18	16	14	12	6	1	1	1	2	2	2	4	7	8	12	25	27	23	22	19	17	14	297
Sep	16	15	15	10	10	8	2	2	1	1	0	2	4	5	9	11	22	28	23	20	18	15	14	12	263
Oct	25	24	23	19	15	14	9	6	3	3	4	5	5	5	8	12	15	17	14	12	13	15	15	15	296
Nov	17	19	18	15	15	16	15	5	4	2	1	3	2	2	2	10	16	12	13	12	12	14	13	13	251
Dec	21	20	20	18	18	17	18	12	11	10	8	7	8	8	9	12	16	16	15	12	12	16	19	20	343
Total	283	279	289	272	263	241	139	75	48	38	36	41	44	52	70	108	179	262	272	257	254	255	250	245	4252

Figure G.10-5 shows the ON Line (One Nevada Line, i.e. the 500 kV line between the Robinson Summit and Harry Allen 500 kV buses) flow and its duration curve with the SWIP North project modeled in the case. ON line flow was observed in both direction, from north to south and from north to south. Table G.10-26 shows the occurrence of ON Line flow from north to south in the hours of the day for each month. It was seen that the ON Line flow was from north to south in 7858 hours in the year, which means that there were 926 hours when the flow was from south to north on the SWIP South 500 kV line. It is noted that the Robinson Summit phase shifter angle was modeled in the PCM specifically to meet the request that LS Power submitted to operate the phase shifters at Robinson Summit substation to maximize the flow through the 500 kV system.

Figure G.10-5: SWIP South Flow and Duration

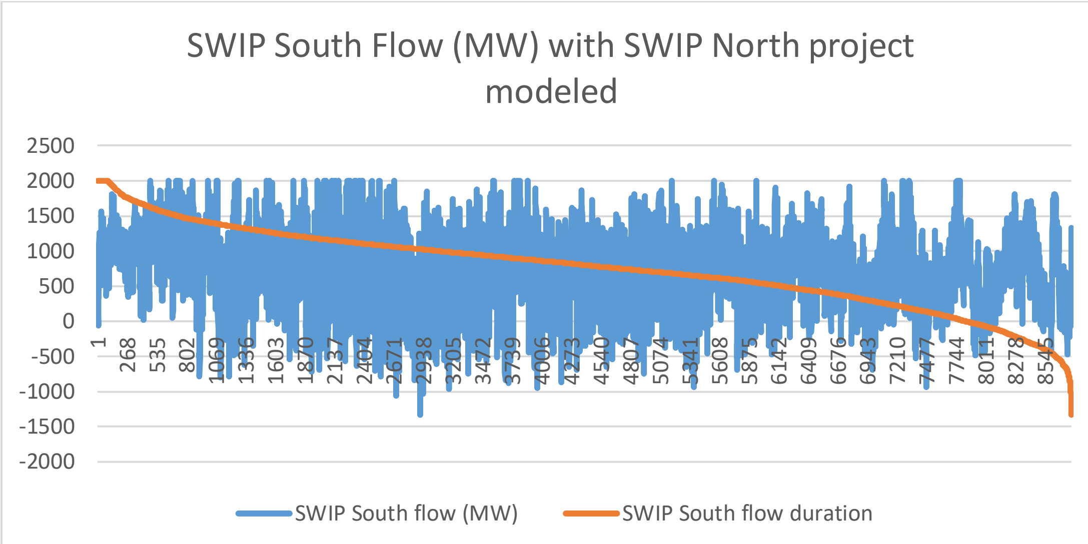


Table G.10-26: Occurrence of SWIP South flow from north to south

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	31	31	31	31	31	31	31	30	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Feb	29	29	29	29	29	29	29	29	23	21	21	21	19	19	22	24	28	29	29	29	29	29	29	29
Mar	31	31	31	31	31	31	31	28	23	22	23	20	19	21	20	27	29	31	31	31	31	31	31	31
Apr	30	29	30	30	30	30	24	12	11	10	10	8	11	8	13	24	29	30	30	30	30	30	30	30
May	31	31	31	31	31	31	15	5	6	7	12	14	20	22	25	30	31	31	31	31	31	31	31	31
Jun	30	30	30	30	30	30	12	7	11	14	17	22	26	27	28	29	30	30	30	30	30	30	30	30
Jul	31	31	31	31	31	31	29	10	16	20	24	22	26	28	28	30	31	31	31	31	31	31	31	31
Aug	31	31	31	31	31	31	30	16	14	18	24	23	24	29	31	31	31	31	31	31	31	31	31	31
Sep	30	30	30	30	30	29	27	17	19	22	28	30	30	30	30	30	30	30	30	30	30	30	30	30
Oct	31	31	31	31	31	30	30	27	24	21	23	26	27	28	28	29	30	31	31	31	31	31	31	31
Nov	29	30	30	29	29	29	28	26	20	20	19	21	23	24	25	27	28	28	28	28	27	27	29	29
Dec	31	31	31	31	31	31	31	30	29	25	28	24	24	28	30	30	31	31	31	31	31	31	31	31

From the above analysis, it was observed that the SWIP North and SWIP South transmission lines not only help to deliver out-of-state generation to the California load, but also can potentially help to send California's generation, especially the solar generation, to the load in other states.

Production cost benefits

The production benefits for ISO ratepayers and the production cost savings of the SWIP North project are shown in Table G.10-27.

Table G.10-27: Production Benefits of the SWIP North project

	Base case with Idaho wind modeled	SWIP North	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,826	9,849	-24
ISO generator net revenue benefiting ratepayers	5,660	5,694	34
ISO transmission revenue benefiting ratepayers	466	468	2
ISO Net payment	3,700	3,687	13
WECC Production cost	13,993	14,020	-27

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Cost estimates

The estimated cost of the project is $636 M in 2020 dollars, based on the 2020 ITP submission. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", and escalated to 2022 dollar based on the inflation ratio provided in the CEC 2021 IEPR[6], the total cost is $870 million.

Benefit-to-cost ratio

The present value of the sum of the production cost of the SWIP North project is shown in Table G.10-28 followed by the calculation of the benefit-to-cost ratio. 50 year project file was used in the present value calculation for conservativeness. No capacity saving was identified in this planning cycle.

Table G.10-28: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of SWIP North project

SWIP North Project	
Production cost savings ($million/year)	13
Capacity saving ($million/year)	0
Capital cost ($million)	636
Discount Rate	7%
PV of Production cost savings ($million)	187
PV of Capacity saving ($million)	0
Total benefit ($million)	187
Total cost (Revenue requirement) ($million)	870
Benefit-to-cost ratio (BCR)	0.22

[6] https://efiling.energy.ca.gov/GetDocument.aspx?tn=240982&DocumentContentId=74834

This analysis, however, does not take into account the transmission capacity rights ISO load serving entities would have to procure to bring Idaho resources to California through other transmission paths.

Conclusions

The economic assessment provides some useful insights that complement the policy-driven analysis for this project, but because of the consideration of the Idaho resources that would be developed for the express purpose of serving California customers, it does not provide a meaningful standalone economic assessment of the viability of the project. The calculated results in this planning cycle demonstrated that the SWIP North project has a benefit-to-cost ration of 0.22, but do not reflect the cost California load serving entities would otherwise have to incur to procure transmission capacity for the Idaho resources. Please refer to the SWIP North discussion in Chapter 3.

G.10.6 SCE North of Lugo congestion

Congestion analysis

Congestion in the SCE North of Lugo area was observed in the base portfolio PCM in this planning cycle as summarized in Table G.10-29. Most of congestion in this area was observed on the Kramer to Victor 230 kV lines under normal conditions and on the Lugo transformers under N-1 contingency of losing one of the two Lugo transformers. Congestion was also observed on other transmission 230 kV or 115 kV lines in the corridor between Kramer and Lugo. Solar generation in this area is the main driver of the congestion.

Table G.10-29: SCE North of Lugo Area Congestion in the Base Portfolio PCM

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
KRAMER-VICTOR 230 kV line #1	34,882	1,476	0	0	34,882	1,476
LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	30,264	1,941	30,264	1,941
KRAMER-VICTOR 230 kV line #2	12,287	544	0	0	12,287	544
P60 Inyo-Control 115 kV Tie	0	0	1,039	572	1,039	572
CALCITE-LUGO 230 kV line #1	597	601	0	0	597	601
VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	418	204	418	204
VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	1	230	822	230	823
VICTOR-LUGO 230 kV line #1	161	15	0	0	161	15
ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	95	32	95	32
VICTOR-LUGO 230 kV line #3	66	4	0	0	66	4
VICTOR-LUGO 230 kV line #4	26	2	0	0	26	2

Congestion mitigation alternatives

Policy need for upgrading the Kramer – Lugo corridor was identified in this planning cycle in Appendix F. The following two alternatives have been assessed to meet the policy needs:

Alternative 1 – Kramer-Lugo 230 kV upgrade that includes upgrading the existing 230 kV lines and converting the Kramer-Victor 115 kV lines to 230 kV lines, and adding the third Lugo transformer; and

Alternative 2 – Kramer-Lugo 500 kV upgrade that include building a new Kramer 500 kV substation with two 500/230 kV transformer and a new 500 kV line between Kramer and Lugo.

The detailed scope of these two alternatives can be found in Appendix F. Production cost simulation was conducted on the base portfolio PCM case with these two alternatives. The simulation results show that both alternatives can effectively mitigate congestion on the Kramer-Lugo corridor including the Lugo transformers. It is noted that these two alternatives were proposed to mitigate issues on the Kramer-Lugo corridor. They are not expected to mitigate the congestion on Path 60 and the congestion on the Calcite-Lugo 230 kV line. Table G.10-30 shows the SCE North of Lugo area congestion after modeling the transmission upgrade in the base portfolio PCM.

Table G.10-30: SCE North of Lugo area congestions in the base portfolio PCM with the transmission upgrade alternatives modeled

Alternative	Scope	SCE North of Lugo area constraints	Congestion cost ($k)	Congestion Hours
A1	Kramer – Lugo 230 kV upgrades	CALCITE-LUGO 230 kV line #1	1,464	1,167
		P60 Inyo-Control 115 kV Tie	756	424
A2	Kramer – Lugo 500 kV upgrades	CALCITE-LUGO 230 kV line #1	1,529	1,310
		P60 Inyo-Control 115 kV Tie	190	132

Table G.10-31 shows how the SCE North of Lugo transmission upgrades impact renewable curtailment in the base portfolio PCM. The transmission upgrades can help to reduce the North of Lugo area curtailment, and the system overall curtailment as well. However, it was seen that when the North of Lugo area curtailment reduced, curtailment in other areas may increase.

Table G.10-31: Renewable curtailment in the Base Portfolio PCM with NOL transmission upgrade modeled compared with the Base Portfolio PCM results

	Base Portfolio PCM			A1: Kramer-Lugo 230 kV			A2: Kramer-Lugo 500 kV		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	31,060	743	2.34%	31,048	756	2.38%	31,061	743	2.34%
SCE Eastern	15,326	618	3.88%	15,315	629	3.94%	15,314	630	3.95%
PG&E Fresno/Kern	17,924	418	2.28%	17,908	434	2.36%	17,911	431	2.35%
SCE NOL	7,403	403	5.16%	7,534	271	3.47%	7,514	291	3.73%
NM	6,281	230	3.53%	6,277	234	3.60%	6,282	229	3.51%
NW	1,876	183	8.90%	1,879	181	8.78%	1,877	182	8.86%
AZ	5,621	166	2.86%	5,630	156	2.70%	5,625	162	2.80%
GridLiance/VEA	7,284	170	2.28%	7,286	168	2.26%	7,294	160	2.15%
WY	3,890	147	3.64%	3,883	154	3.82%	3,880	157	3.88%
SCE EOL	5,465	125	2.23%	5,467	122	2.19%	5,469	120	2.15%
PG&E Diablo OSW	7,635	98	1.27%	7,633	101	1.30%	7,634	99	1.28%
SCE Vestal-Rector	2,349	65	2.69%	2,346	67	2.78%	2,348	66	2.73%
PG&E Central Coast	2,797	53	1.85%	2,795	54	1.91%	2,796	54	1.88%
SCE Ventura	1,288	51	3.83%	1,287	53	3.96%	1,286	54	4.00%
SCE Antelope 66 kV	926	23	2.39%	926	22	2.36%	926	22	2.33%
PG&E Central Valley	5,448	15	0.27%	5,447	16	0.29%	5,447	15	0.28%
SCE LA Basin	315	5	1.46%	315	5	1.50%	315	5	1.48%
PG&E North Valley	2,240	3	0.13%	2,240	3	0.13%	2,240	3	0.13%
PG&E Humboldt OSW	618	2	0.30%	618	2	0.29%	618	2	0.29%
PG&E GBA	110	1	0.71%	110	1	0.74%	110	1	0.68%
IID	308	0	0.05%	308	0	0.02%	308	0	0.02%
SDGE IV	8,296	0	0.00%	8,296	0	0.00%	8,296	0	0.00%
SDGE San Diego	262	0	0.01%	262	0	0.01%	262	0	0.01%
Total	**134,719**	**3,518**	**2.54%**	**134,808**	**3,429**	**2.48%**	**134,813**	**3,425**	**2.48%**

Production benefits

Economic assessment was conducted for these two alternatives to compare how much economic benefit they create for ISO ratepayers. The production benefit for ISO ratepayers and the production-cost savings of the SCE North of Lugo area transmission upgrade alternatives are shown in Table G.10-32.

Table G.10-32: Production Benefits of SCE North of Lugo Upgrades

	Base case	Kramer-Lugo 230 kV		Kramer-Lugo 500 kV	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,761	79	9,752	87
ISO generator net revenue benefiting ratepayers	5,760	5,788	28	5,782	22
ISO transmission revenue benefiting ratepayers	457	365	-92	365	-92
ISO Net payment	3,623	3,608	15	3,605	18
WECC Production cost	13,937	13,926	11	13,954	-17

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Cost estimates

The estimated cost of Alternative 1 and Alternative 2 of the SCE North of Lugo transmission upgrade is $482 million and $700 million, respectively, in 2020 dollars. The detailed discussion of the cost estimate for these two alternatives can be found in Appendix F. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", and escalated to 2022 dollars based on the inflation ratio provided in the CEC 2021 IEPR[7], the total cost of Alternative 1 and the Alternative 2 is $627 million and $910 million, respectively.

Benefit-to-cost ratio

The present values of the economic benefit of the SCE North of Lugo alternatives are shown in Table G.10-33 along with the calculation of the benefit-to-cost ratio. The project economic life of Alternative 1 is assumed to be 40 year as it is mainly upgrading existing transmission lines. The project economic life of the Alternative 2 is assumed to be 50 year, as the Kramer-Lugo 500 kV line is a new line. No capacity savings were identified in this planning cycle.

Table G.10-33: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of SCE North of Lugo Upgrade Alternatives

	Alternative 1 – Kramer – Lugo 230 kV Upgrade	Alternative 2 – Kramer – Lugo 500 kV Upgrade
Production cost savings ($million/year)	15	18
Capacity saving ($million/year)	0	0
Capital cost ($million)	482	700
Discount Rate	7%	7%
PV of Production cost savings ($million)	214	260
PV of Capacity saving ($million)	0	0
Total benefit ($million)	214	260
Total cost (Revenue requirement) ($million)	627	910
Benefit-to-cost ratio (BCR)	0.340	0.286

[7] https://efiling.energy.ca.gov/GetDocument.aspx?tn=240982&DocumentContentId=74834

Conclusions

The Kramer-Lugo 230 kV alternative's benefit-to-cost ratio is higher than the benefit-to-cost ratio of the Kramer-Lugo 500 kV alternative. Both alternatives are effective to mitigate congestion in the SCE North of Lugo area.