CPUC AVOIDED TRANSMISSION AND DISTRIBUTION COST STUDY TO SUPPORT THE AVOIDED COST CALCULATOR

Avoided Transmission Costs Draft Research Plan

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1.0 Draft Research Plan

Pacific Northwest National Laboratory (PNNL) and Lawrence Berkeley National Laboratory (LBNL) have been contracted by the California Public Utilities Commission (CPUC) Energy Division (ED) to perform a study which explores and selects an improved methodology to estimate avoided electricity transmission and distribution (T&D) infrastructure costs that can be attributed to the presence of distributed energy resources (DERs). PNNL is performing the study for avoided electricity transmission infrastructure costs and LBNL is performing the study for avoided electricity distribution infrastructure costs. This document summarizes CPUC's research questions related to avoided transmission infrastructure costs and PNNL's proposed technical approach to answer these questions.

1.1 Background

In accordance with D.22-05-002, CPUC Energy Division (ED) staff were authorized to conduct a study to analyze avoided T&D costs, which were noted as needing improvement. The purpose of this study is to estimate these avoided T&D costs more accurately. Avoided T&D costs inform the Electric Avoided Cost Calculator (ACC), which is used to improve the accuracy of calculating the benefits of demand-side resources. Benefits of DERs are used for cost-effectiveness analyses which are part of a cost-effectiveness process used by the CPUC to determine costs and benefits of customer programs. ACC estimates are also used to represent the lifecycle value of energy efficiency programs as well as set the basis for export compensation for behind-the-meter net-energy metering and net billing. The ACC provides hourly system-level costs of producing electricity (in $/kWh) for a 30-year time horizon.[1]

The scope of the study—as outlined in the Administrative Law Judge's Ruling Requesting Party Comments On Funding For an Avoided Transmission and Distribution Cost Study, Rulemaking 22-11-013—is to help the CPUC better understand the marginal costs of constructing and operating T&D infrastructure. The study will examine factors that contribute to the needs of building more T&D infrastructure, how DERs can help defer or avoid those needs, and develop modeling approaches to calculate avoided T&D costs.

1.1.1 Study Objectives

The objective of the Study is to develop a methodology to help the CPUC better understand the marginal costs of constructing and maintaining T&D infrastructure and ultimately to determine estimates of avoided T&D costs to be included in the 2026 ACC. This study will examine how the addition of DERs in California impacts the required transmission and distribution system infrastructure capacity and translates those impacts in a form of marginal costs. This work will consider a range of possible cost methodologies, including enhancing existing ACC empirical approaches, based on costs directly reported by utilities, but also adapting advanced distribution and transmission modeling techniques and scenarios specifically for estimating avoided transmission and infrastructure.

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[1] For further detail on the use of the ACC see the CPUC's "2024 Distributed Energy Resources Avoided Cost Calculator Documentation" available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2024-acc-documentation-v1b_clean_posted_nowm.pdf.

1.1.2 Key Research Questions

Key questions the study will address (as outlined in the Administrative Law Judge's Ruling Requesting Party Comments On Funding For an Avoided Transmission and Distribution Cost Study, Rulemaking 22-11-013) include:

1) Assessment of the CPUC's current method for valuing marginal transmission and distribution avoided costs.
2) Assessment of the possible methods to estimate avoided T&D costs, which may include, but are not limited, to:
    a) using the costs of transmission projects that were planned but later canceled as the basis for avoided transmission costs;
    b) developing a plan based on a counterfactual load forecast, such as the "No New DER" scenario that has been used to determine other avoided costs;
    c) using historical data and data from other jurisdictions to develop "what if" scenarios of possible configurations of California's transmission infrastructure if electricity demand were different.
    d) Assessment of possible methods to estimate marginal transmission and distribution costs by climate zone or more granular geographic areas. In discussions with the CPUC it was determined that transmission zones will be used for geographic disaggregation.

1.2 Summary of Approach

To develop the draft research plan, PNNL has assessed the CPUC's current methodology for valuing marginal transmission costs to understand opportunities for improvement, as summarized in Section 2.0. Key opportunities for improvement include the need for a methodology that is repeatable, not solely dependent on utility empirical data, provides a clear and consistent framework for valuing unspecified[1] as well as deferred or avoided costs, and provides increased geographic granularity of transmission avoided costs.

PNNL proposes an approach that utilizes the CAISO transmission planning dataset and approved transmission portfolio to investigate the impact of load growth on the transmission projects. The proposed methodology, as detailed in Section 3.0, assesses the impact of load reduction on the need for transmission projects and uses this information to calculate transmission avoided capacity costs and distribute those costs over time and to geographic zones. The approach will also compare the CPUC's current methods for estimating transmission avoided capacity costs to state-of-the-art methods that may be in use in other locations and jurisdictions and produce estimates as practicable. For methods that are identified that may be worth future consideration, PNNL will outline the process and data needs required to implement. Throughout the study, PNNL will coordinate with LBNL to ensure methodological and assumption compatibility (such as geographic resolution and coincident boundaries) with the distribution system avoided cost investigation (performed by LBNL) as much as possible based on existing modeling and data constraints.

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[1] Our methodology proposes to estimate unspecified transmission avoided costs, in the sense that future load growth driven projects, that are yet to be determined, would be avoided. We do, however, propose to utilize existing projects (specified costs) as the input to estimate those unspecified costs. This is consistent with the current approach in the ACC.

An expected project timeline with key deliverables is provided in Section 4.0 and key questions for stakeholders are highlighted in Section 5.0.

2.0 Current Methods for Valuing Transmission Avoided Costs

This Section provides a brief summary of the CPUC’s current methods for valuing both avoided and deferred transmission costs and includes a review of key opportunities for improvement which will be addressed with PNNL’s proposed methodology.

2.1 Current Avoided Cost of Transmission Calculation

The CPUC’s most recent 2024 Distributed Energy Resources Avoided Cost Calculator Documentation (2024 ACC Documentation)[1] defines transmission avoided capacity costs as “…the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems…IF the peak loading reductions can be obtained in the right amount, right location, and with the right dependability.” Critically, the calculator does not consider *how* the load reduction is achieved, taking it as an input assumption instead.

Currently, the calculator uses two separate methodologies to develop the avoided and deferred cost for transmission projects. Projects impacting the full system load use the Discounted Total Investment Method (DTIM), while projects impacting more distinct load pockets use the Locational Net Benefit Analysis (LNBA). In both cases, each transmission project is associated with load growth. The present value (PV) of the cost of the transmission projects, and the load growth are calculated and the ratio of the two becomes the marginal investment. This is then annualized to give the marginal transmission capacity cost (MTCC) in $/MW-Yr. The key differences between the DTIM and LNBA methods, summarized in Table 1, are the type of cost change that is used to calculate the PV, and the load growth the projects are attributed to. The LNBA method uses a one-year deferment of the cost, and only a fraction (locational part) of the total system load. The DTIM method calculates the PV of avoiding the project’s cost for one year, and the full system load growth is used.

Table 1 Key Inputs to Avoided Transmission Calculation

	Discounted Total Investment Method (DTIM)	Locational Net Benefit Analysis (LNBA)
Metric Interpretation	The value of deferring the revenue requirement cost of the project and all future replacements by one year.	The deferral by one year of all investments in the multi-year capital plan.
Load growth	System load	Locational fraction of load
Service Territory Adjustment	None	Peak loading %

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[1] https://www.ethree.com/wp-content/uploads/2025/02/2024-ACC-Documentation-v1b_clean.pdf

2.2 Spatial and Temporal Allocation

The current calculator uses the utilities' jurisdiction as the only level of spatial resolution. In the 2024 ACC Documentation it is noted that this is partially by design, as the location needs may shift over time, making forecasting more difficult and less accurate. As stated in the key research questions (Section 1.1.2), however, Rulemaking 22-11-013 specifically lists geographic granularity as a development of interest.

Temporally, the calculated costs are distributed using the peak capacity allocation (PCAF) method, which selects the 20 to 250 hours of highest load based on historical data from CAISO's Energy Management System dataset[1]. More details on the PCAF method are provided in Section 3.1.5.

Note that since transmission capacity is represented by a binary build/do not build decision, the allocation of its avoided cost in time is fundamentally different from energy avoided costs. While energy costs can be avoided at different amounts at different times, the transmission capacity cost is avoided exactly once, and the distribution in time is only an allocation of that annualized investment.

2.3 Assessment of Current Methods

In our assessment of current methods, PNNL has identified the need for a methodology that is repeatable, not solely dependent on utility empirical data, provides a clear and consistent framework for valuing unspecified[2] deferred or avoided costs, and provides increased geographic granularity of transmission avoided costs.

Key findings and recommendations:

1. There is a lack of clarity around the decision-making process for determining the appropriate set of transmission projects that may be treated as potentially deferrable. An example for the spectrum of interpretation is PG&E's 2019 GRC phase II filling, where only 6 of 73 projects were judged to be deferrable[3], resulting in an MTCC of 12.02 $/kw-year. In a testimony under the same docket on November 20th of 2020, the Solar Energy Industries Association (SEIA), argued that based on the transmission cost causation study in the same PG&E filling[4], around 27% of transmission projects are capacity related leading to an MTCC of 52.45 $/kw-year[5]. This discrepancy highlights the lack of clarity about how to determine the transmission capacity associated with load growth, even when looking at the same data. A key objective of this study is to provide a clear and repeatable procedure for determining this key input to the MTCC.

2. The estimated transmission avoided costs have tended to be "lumpy" over time, with large changes across versions of the ACC and across utilities. While some variation is

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[1] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx#Historical

[2] As stated previously, our methodology will estimate unspecified costs related to estimated projects needed for load growth, but will utilize existing projects (specified costs) as a proxy for those project costs.

[3] Pacific Gas and Electric Company 2020 General Rate Case Phase II Exhibit (PG&E-2) Ch. 4.

[4] Pacific Gas and Electric Company 2020 General Rate Case Phase II Exhibit (PG&E-2) Ch. 5.

[5] Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, November 20, 2020.

expected as the system needs and transmission costs change and methods are updated, the changes should be modest. There are two main inputs to the MTCC: the cost of avoided transmission projects and their corresponding load growth. The current use of two different methods for computing the MTCC—DTIM or LNBA— depending on the classification as system or locational, has the potential to cause inconsistencies. The classification decision should ideally have a small impact on estimated values, especially for projects that are on the boundary of the decision options. Previous versions of the ACC have used 1-2 projects per utility for the avoided transmission costs. This produces estimates that are highly dependent on the specific projects used for estimation with a low sample size. An objective of this study is to provide a clear and consistent framework for valuing projects across a range of sizes for unspecified costs

3. While many portions of the ACC are provided at the spatial resolution of climate zones, the transmission avoided costs are constant over the entire footprint of each utility. Another key objective of this study is to better evaluate the geographic impacts of load reduction and produce a finer spatial granularity of values.

3.0 Proposed Methods for Valuing Transmission Avoided Costs

This Section provides a detailed summary of PNNL's proposed method for valuing both avoided and deferred transmission costs. Our proposed method, which is a power flow assessment approach relating the impact of hypothetical changes in load on approved transmission projects to investigate avoided costs, is provided in detail. We also include the option of exploring a production cost modeling approach which is advantageous in its 8760 annual hours view as well as production of dollar valued estimates, as well as a third option to harmonize inputs of existing methods in a more cohesive way to provide a benchmark based on current methods. Throughout this section, orange callout boxes are used to provide key takeaways and intuitive explanations of the proposed power flow assessment method.

3.1 Power Flow Assessment

The proposed approach uses the CAISO transmission planning dataset and approved transmission portfolio to investigate the impact of load growth on the approved transmission projects. The approach is comprised of associating hypothetical load reduction needed to theoretically avoid a given, approved transmission project, using that to calculate marginal costs, and then distributing the costs spatially and temporally. The primary objective is to develop a repeatable methodology for obtaining the two key inputs used in the MTCC calculation. The core calculations will be AC power flow and contingency analysis.

Note:
This assessment is not intended to claim that any approved transmission project may or should be avoided. Instead, the portfolios are used as current proxies to ask what it *would have taken* to avoid them. This hypothetical, "historical" analysis, is then projected forward as the future avoided marginal cost.

3.1.1 Input Data

The main data inputs are the transmission planning cases that come from CAISO's market participation portal. These planning cases include power flow models, contingency definition files, as well as change files of the proposed transmission projects in the planning cycle. Cost information for the projects is included in the final plan document. Rather than break down the various projects into transmission planning drivers (e.g., reliability, economic, or policy), the power flow assessment approach will treat all projects equally and evaluate the impact of load reduction on the need for these projects. More context around how the methodology applies to non-reliability driven projects is presented in Appendix B. The current plan is to break down the load regionally, roughly into the transmission zones defined by CAISO, shown in Figure 1.

Zones are indicated in the power flow case and PNNL will work with CAISO to obtain any additional aggregation mapping needed.[1] The motivation behind this choice is that it should indicate portions of the system that have similar transmission impacts. This does pose a challenge for the integration with the rest of the ACC, as it is subdivided into climate zones, which will not necessarily map neatly to the transmission zones. Should a different mapping be

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[1] For example, CAISO indicated that the LA metro zone consists of serval "zones" in the power flow case.

desired, the regions can be modified upon request, however, this will require close work with CAISO to correctly map buses in the power flow model.

The load growth assumptions are those embedded in the CAISO planning cases, unless the CPUC instructs the use of different load projections. As noted in CAISO's plan, the load comes from the CEC and CPUC. There should be several years' worth of load forecasts given, which will give this methodology the option to study different load conditions with respect to the transmission projects.

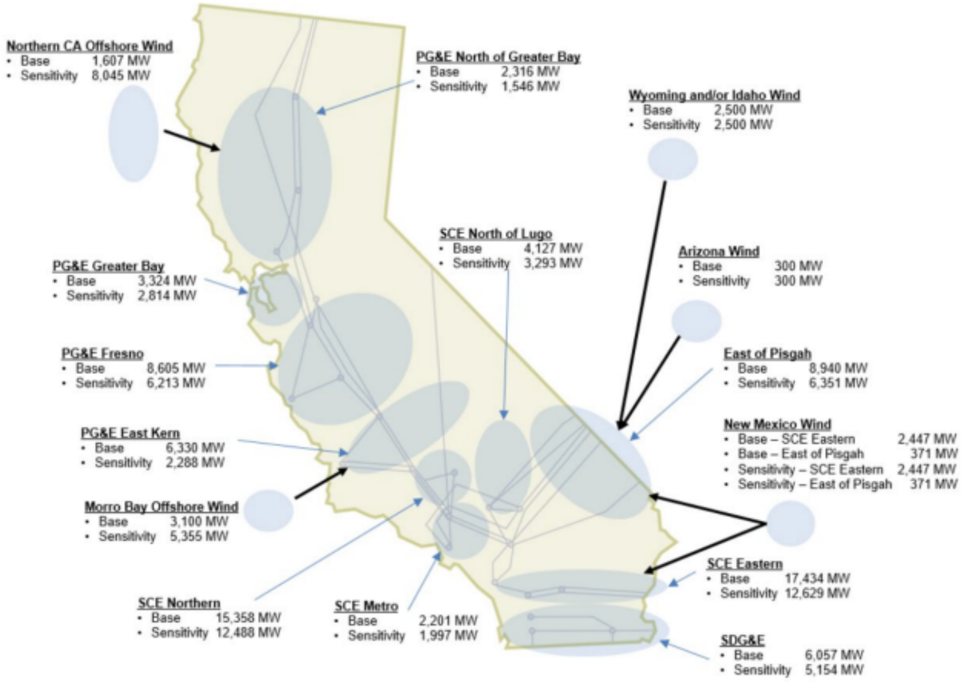

Figure 1: CAISO Transmission Zones From the 2023-2024 TPP[1]

3.1.2 Impact of Load Reduction

The evaluation of load reduction is performed by removing a particular transmission project and reducing load until no thermal violations in any of the load flows and contingencies are observed[2]. Two edge cases are treated separately from the subsequent analysis:

1. *After removing the transmission project, no violations are observed*. This analysis can only deduce that the project is needed for reasons other than those captured by the power flow and contingency analysis and is therefore excluded from the list of projects where load reduction would provide a benefit.

2. *After removing a project, violations persist irrespective of load reduction*: Similar to the other edge case, this suggests that the project is needed for reasons that are not adequately captured by this methodology of load reduction, and therefore, will not be considered as a project where load reduction is relevant.

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[1] https://www.caiso.com/documents/iso-board-approved-2023-2024-transmission-plan.pdf

[2] The methodology currently excludes voltage violations as managing voltage issues with load reduction is not a common transmission system operating procedure.

In both edge cases the marginal investment of the project (calculated in Equations (9) or (14) below) will be 0 $/MW. For all other cases, the process illustrated in Figure 2 will be used to determine the load reduction to associate with each transmission project.

Edge cases are scenarios where the transmission avoided cost would be equal to zero $/MWh, meaning that the projects are non-deferrable. The edge cases represent situations where either the projects are truly non-deferrable *or* PNNL's analysis is not suited to assess them.

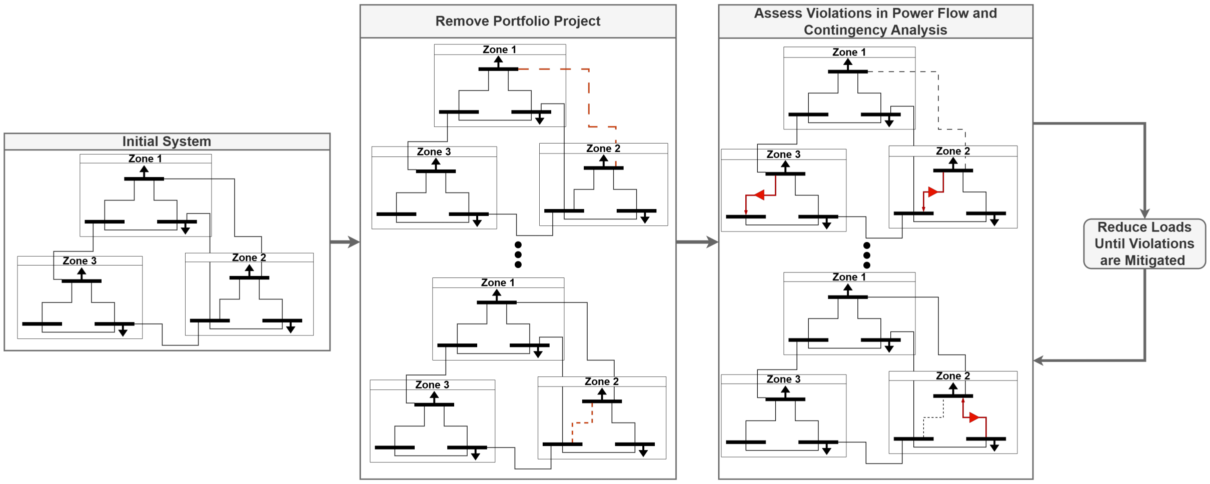

Figure 2: Illustration of power flow assessment to associate load reduction need with transmission projects. The dashed line represents one of the transmission portfolio projects that are deactivated to observe the degree of load reduction necessary to avoid violations.

Load reduction will be distributed spatially using Power Transfer Distribution Factors (PTDFs) during normal operations, and compensated PTDFs for effects under contingency. These are sensitivities that indicate what fraction of a transaction between two buses flows over a given branch element. In our analysis, we'll assume the receiving bus is the distributed reference bus, as described in the Section 3.1.3, which allows to consider injections only, rather than all pair-wise combinations. For a branch l in the set of violating branches, $\hat{L}$, the sensitivity $PTDF_{l,i}$, with respect to a reduction in load in zone $i \in Z$ containing loads $j \in J_i$ can be calculated as:

$$\mathrm{PTDF}_{l,i} = \sum_{j \in J_i} PTDF_{l,j} \cdot \alpha_j. \tag{1}$$

Here, α_j is the load participation factor, defined as:

$$\alpha_j = \frac{P_j}{\sum_{j \in J_i} P_j}, \quad \forall i \in Z \tag{2}$$

where and P_j is the nominal load in MW. The value calculated in (1) provides a linearized sensitivity[1] between injections in zone i and flows on branch l.

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[1] It is stressed that while the sensitivity calculated in (1) is linearized, this is only used to allocate load reduction. The actual analysis uses the non-linear AC power flow.

Each violation has two quantities of interest. The first, is the magnitude, ϵ_l, which will be measured as a percent of the thermal rating:

$$\epsilon_l = \frac{\max(|f_l| - r_l, 0)}{r_l} \times 100\% \tag{3}$$

where f_l is the flow in MVA for line l, and r_l is the thermal rating[1]. The second quantity of interest is the direction of the violation. Branches are defined with an orientation, where flow is defined as *positive*, if it flows from the "from" bus to the "to" bus of the branch. The directionality of each violation is captured as:

$$s_l = \mathrm{sgn}(\mathrm{f_l}), \tag{4}$$

Where $\mathrm{sgn}(\cdot)$ is the sign function, returning +1 if the argument is positive, and -1 if it is negative. Loads should only be reduced if that reduction will aid in alleviating the observed violation. Since a load reduction is equivalent to a positive injection, if $s_l = +1$, only zones, i, with $\mathrm{PTD}F_{l,i} < 0$ should have their loads reduced. Conversely, if $s_l = -1$, only zones, i, with $\mathrm{PTD}F_{l,i} > 0$ should be reduced. Additionally, only zones, i, with $|PTDF_{l,i}| \geq 0.05$ will be considered for any violating element. This threshold is intended to exclude minimal impacts and is based on the 5% DFAX threshold in the transmission capability assessment CAISO uses for the CPUC's resource planning process[2]. For a given violation $l \in \hat{L}$, we can therefore define a subset of zones, Z_l where load should be reduced for the violation, defined as:

$$Z_l = \{i \,|\, i \in Z \cap |PTDF_{l,i}| > 0.05 \cap PTDF_{l,i} \cdot s_l < 0\} \tag{5}$$

At each iteration step, the system load will be reduced by a certain MW amount, ΔP_t. This load will be allocated along two dimensions. The first allocates between the set of observed violations $\hat{L}$. This will be done proportionally based on ϵ_l from (3):

$$w_l = \frac{\epsilon_l}{\sum_{l \in \hat{L}} \epsilon_l}, \tag{6}$$

where w_l is the fraction of ΔP_t allocated to violation l. Second, for each violation, the load reduction will be distributed to the zones, $i \in Z_l$, proportionally based on the magnitudes of $\mathrm{PTD}F_{l,i}$:

$$w_{i,l} = \frac{|PTDF_{l,i}|}{\sum_{j \in Z_l} |PTDF_{l,j}|}, \tag{7}$$

where $w_{i,l}$ is the fraction of the load reduction allocated to zone i from the allocation for violation l. Note that $w_{i,l}$ is a fixed quantity based on the system topology, while w_l will change from iteration to iteration based on the observed violations. The total load reduction, $\Delta P_{i,t}$, in each zone i for iteration t becomes:

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[1] For contingency analysis this is the emergency rating.

[2] https://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf

$$\Delta P_{i,t} = \Delta P_t \sum_{l \in \hat{L}} w_{i,l} \cdot w_l \tag{8}$$

Note, that this is basically a matrix-vector multiplication between the PTDF weights, $w_{i,l}$, and the violation weights, w_l. Finally, the load reduction in each zone can be distributed to the individual loads based on the participation factors in (2). A sample calculation, illustrating the load reduction allocation, is provided in Appendix A.

The load reduction is determined based on observed violations in the power flow and contingency analysis, following removal of a transmission project. The load reduction is distributed spatially based on the sensitivity of each zone to the set of observed violations.

3.1.3 Generation Reduction

Since CAISO operates as a balancing authority, any load reduction within its footprint should be matched by generation reduction to maintain the interchange flows. Power flow software typically contains participation factors for generators to model distributed slack behavior, where the set of generators make up the difference in power balance based on these factors. The distributed slack mode will be applied to make sure that all generation change comes from CAISO and will be proportional either to generator size or to the participation factors provided in the CAISO planning cases.

Reducing load requires reducing generation as well in the power flow cases. The reductions will be distributed in a way that maintains the relative relationship between the system dispatch.

3.1.4 Expected Outputs

The power flow assessment will provide a MW quantity, ΔP_x, of load reduction necessary to alleviate all violations when each transmission project in the studied portfolio, $x \in T_x$, is removed. Set T_x excludes the projects meeting one of the two edge cases described in Section 3.1.2. Each transmission project is associated with a CAPEX cost, $c(x)$ in the CAISO transmission planning database. The marginal investment for each project, MC_x, is the ratio of cost to load change:

$$MC_x \text{ [\$/MW]} = \frac{PV\big(c(x)\big)}{PV(\Delta P_x)}, \tag{9}$$

where $PV(\cdot)$ calculates the present value (PV) over the time horizon of interest. The power flow modeling does not distinguish between system and local transmission in the manner that the current ACC documentation does. This project will use the DTIM method for computing the MTCC from the estimated cost and load values. Location specific values will be estimated using spatial allocation as outlined in Section 3.1.5. The overall value will be the sum over all transmission projects, annualized with factor f_{ann}, to include RECC and other adjustments using the same DTIM method as the current ACC, so that the final avoided cost will be:

$$MTCC[\$/\text{MW-year}] = \sum_{x \in T_x} f_{\text{ann}} \cdot MC_x. \tag{10}$$

A review of methods for estimating transmission avoided capacity costs will also be conducted to identify other methods that are currently in use in other locations and jurisdictions. The review will identify any methods or developments that have improved the state of the art. The project will include a computation of the MTCC value for other methods identified in the literature review that use data and modeling done as part of this project. For methods that would require different modeling approaches or data requirements, the data and modeling required will be summarized and explained, but values will not be estimated.

Intuitive explanation:
The marginal investment for each transmission project with respect to load growth is the ratio of the transmission project's cost and the load reduction that would be needed to eliminate the need for the project.

An overview of how the output from the power flow analysis is used to calculate the MTCC is illustrated in Figure 3. Note that according to (9), as the amount of necessary load reduction increases, the avoided cost is smaller. In this way, projects that may not be primarily focused on load should exhibit a large ΔP_x and therefore have little impact the total marginal investment.

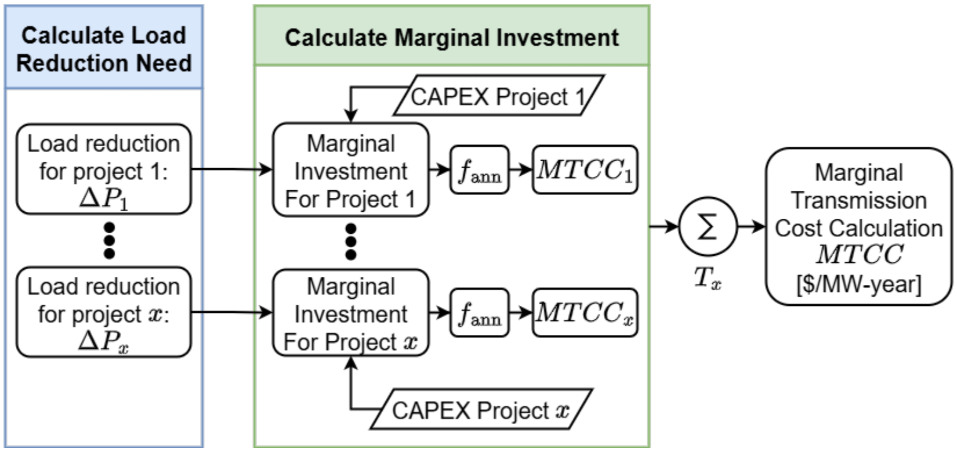

Figure 3: MTCC calculation based on power flow assessment.

3.1.5 Spatial and Temporal Allocation

In (9) the change of load is a system (utility) wide value. However, since the load change is made up of changes attributed to individual zones, the MTCC can be allocated based on the proportional change in each zone i:

$$MTCC_{i,x} = \frac{\Delta P_{i,x}}{\Delta P_x} \times MTCC_x, \tag{11}$$

where $\Delta P_{i,x}$ is the accumulation over all iterations, t, of load changes in zone i for transmission project x according to (8), and $MTCC_x$ is the product of the marginal investment MC_x and the annualization factor f_{ann}.

Temporally, the MTCC can be attributed similarly to the current calculator and allocated by peak load allocation factors (PCAFs)[1] using CAISO's historical energy management system data[2]. For this analysis, the latest data from 2024 will be used. PCAFs are calculated for each utility using their utility-level load using N, usually between 20 and 250, peak load hours. PCAF values for a utility are calculated as:

$$PCAF_h = \frac{\max(\text{load}_h - \tau,\ 0)}{\sum_h \max(0, \text{load}_h - \tau)}, \tag{12}$$

where $PCAF_h$ is the allocation factor at hour h, load_h is the historical load in MW at hour h, and τ is the maximum demand minus one standard deviation, or the closest value ensuring that the number of hours with loads above the threshold falls between 20 and 250 hours. The PCAF values are zero or greater and sum to 1 across 8760 hours. The MTCC in zone i for project x is temporally allocated as:

$$MTCC_{h,i,x} = \text{PCAF}_h \times MTCC_{i,x}. \tag{13}$$

Summing over all transmission projects T_x gives the total MTCC. The full process, from load change to MTCC with zonal and hourly allocation, is illustrated in Figure 4.

Intuitive explanation:
The MTCC is allocated both spatially and temporally. Spatial allocation to each zone is proportional to the calculated change of load need in that zone. Temporal allocation is based on historical hours of peak load.

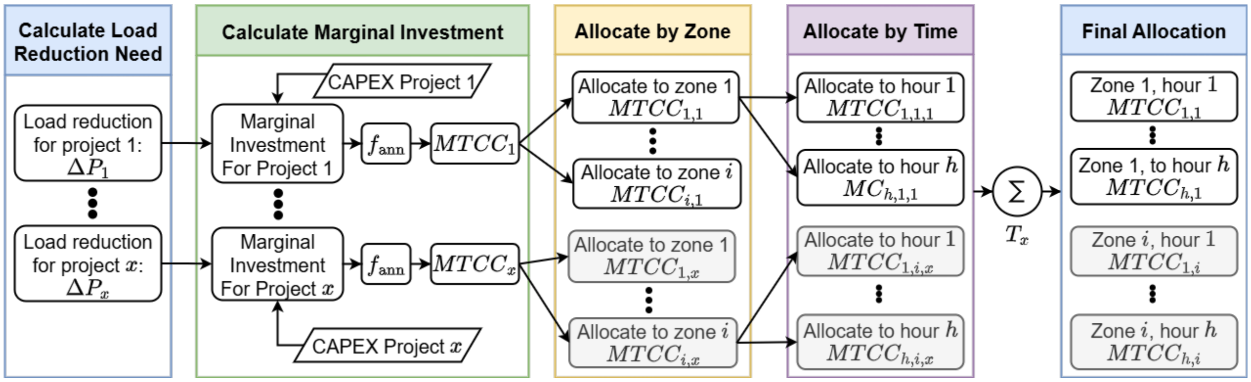

Figure 4: Allocation of MTCC in space (zone) and time (hour).

3.1.6 Incorporating multiple power flow scenarios in time

The CAISO transmission planning process considers three general cases: summer peak, spring off-peak, and winter peak. The study will initially consider the summer-peak scenario only to prototype the power flow assessment. Upon successful implementation, an expansion to leverage the additional scenarios will be completed, time allowing. In addition, the multiple study years in the transmission planning process represent another dimension in the scenario matrix. The influence of multiple scenarios in time on the calculation procedure is described in the following section.

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[1] https://www.ethree.com/public_proceedings/energy-efficiency-calculator/
[2] https://www.caiso.com/generation-transmission/resource-adequacy#Historical

Since the avoided transmission cost calculation deals with capacity, the process of allocating over time has to do with attributing which periods drive the need for infrastructure upgrades. Since the construction of a transmission project is an integer decision, the maximum load reduction found over all studied scenarios would need to be achieved, in order to successfully avoid the project. As a result, when adding more scenarios Equation (9) changes to:

$$MC_x\,[\$/\mathrm{MW}] = \frac{PV\big(c(x)\big)}{\max_{s\in S} PV\big(\Delta P_{s,x}\big)} \tag{14}$$

Where $\Delta P_{s,x}$ is the load reduction needed for each scenario s of the studied scenario set S. The maximum operation indicates that the maximum load reduction is necessary to achieve the avoided investment. The use of the present value operation is especially important for placing different study years on a level basis. For each transmission project, the MTCC can then be distributed to the scenarios as,

$$\mathrm{MTCC}_{s,x} = \frac{\mathrm{PV}(\Delta P_{s,x})}{\sum_{s\in S}\mathrm{PV}(\Delta P_{s,x})} \cdot MTCC_x. \tag{15}$$

The spatial resolution follows as in (11) except that it distributes on a scenario basis:

$$MTCC_{i,s,x} = \frac{\Delta P_{i,s,x}}{\Delta P_{s,x}} \times MTCC_{s,x}, \tag{16}$$

where $\Delta P_{i,s,x}$ is the load change associated with zone i in scenario s for project x,and $\Delta P_{s,x}$ is the total load change for scenario s and project x.

The PCAF method can also be broken up by scenario, by mapping each hour to a subset of the scenarios studied. That is, (12) is modified to

$$PCAF_{h,s} = \begin{cases} \dfrac{\max(\mathrm{load}_h - \tau_s, 0)}{\sum_{h\in hr(s)} \max(\mathrm{load}_h - \tau_s, 0)} & h \in hr(s) \\ 0 & \text{otherwise} \end{cases} \tag{17}$$

Where $hr(s)$ returns the set of hours mapped to scenario s, and τ_s is a scenario specific threshold.

The final spatiotemporal allocation of MTCC for by zone i and hour h sums over the set of scenarios and transmission projects:

$$MTCC_{h,i} = \sum_{x\in T_x}\sum_{s\in S} \mathrm{PCAF}_{h,s} \times MTCC_{i,s,x}. \tag{18}$$

Figure 5 expands upon the process overview from Figure 4 to illustrate how the power flow scenarios fit into the full calculation procedure.

Intuitive explanation:
When multiple power flow scenarios, representing different operational times, are used, the MTCC considers the *maximum* load reduction needed across these scenarios. The total investment is then allocated proportionally to the load change in each scenario. Temporally, each scenario distributes value to a subset of hours associated with that scenario, rather than to the full year.

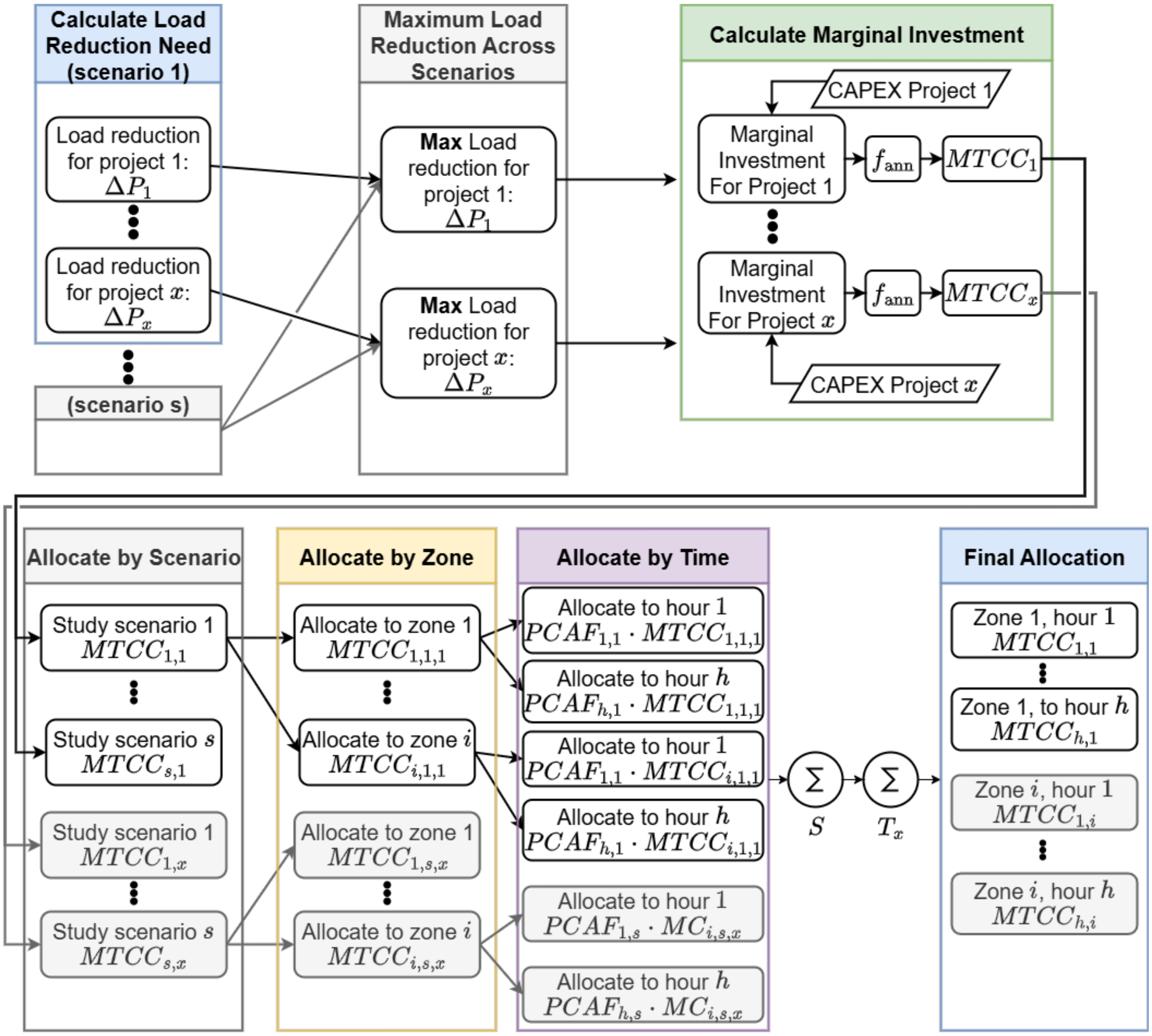

Figure 5 Allocation of MTCC in space (zone) and time (hour) using multiple scenarios (power flow cases).

3.2 Production Cost Modeling Assessment

PNNL has also developed an alternative approach, using production cost modeling to assess the avoided transmission costs. The benefit of a production cost modeling approach is that it inherently considers all 8760 hours and that it naturally produces dollar valued quantities that can be helpful in the development of a calculation method. The PNNL team will develop a whitepaper on the proposed production cost approach for the CPUC to consider in future iterations. At this time, however, the preferred approach from the CPUC is the power flow analysis and the production cost assessment will not be carried out.

3.3 GRC Filing Assessment

Both the PG&E's GRC Phase II filing[1], as well as the SEIA testimony challenging the calculated MTCC value[2] illustrate that there is already a fair amount of transmission project information that enters the record as part of the transmission planning and rate case processes. The current calculation methods apply existing tags, aggregations, and accounting measures to derive the MTCC. In the event that the power flow analysis proves untenable or unreliable, PNNL will propose a harmonization of existing processes, for a calculation of MTCC that relies solely on information already in other filings. The main detraction for this approach, is that it will not provide any of the additional spatial resolution of the power flow modeling.

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[1] Pacific Gas and Electric Company 2020 General Rate Case Phase II Exhibit (PG&E-2)

[2] Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, November 20, 2020.

4.0 Project Timeline

Once a final research plan is developed in coordination with CPUC and stakeholders, preliminary analysis and results from PNNL's approved method will be disseminated to the CPUC ED by August 31, 2025. Final analysis and results are then proposed for September 30th, 2025. A draft report will be released to the CPUC ED by November 30th, 2025.

5.0 Initial Questions for Stakeholder Comment

1. PNNL would like stakeholder input on our assumption of using CAISO's recommended transmission projects rather than transmission projects that are in the queue but not built or under construction. This assumption can result in a "lumpy" investment trajectory (and impact to avoided cost) on a biennial basis.

Appendix A – Sample Load Reduction Calculation

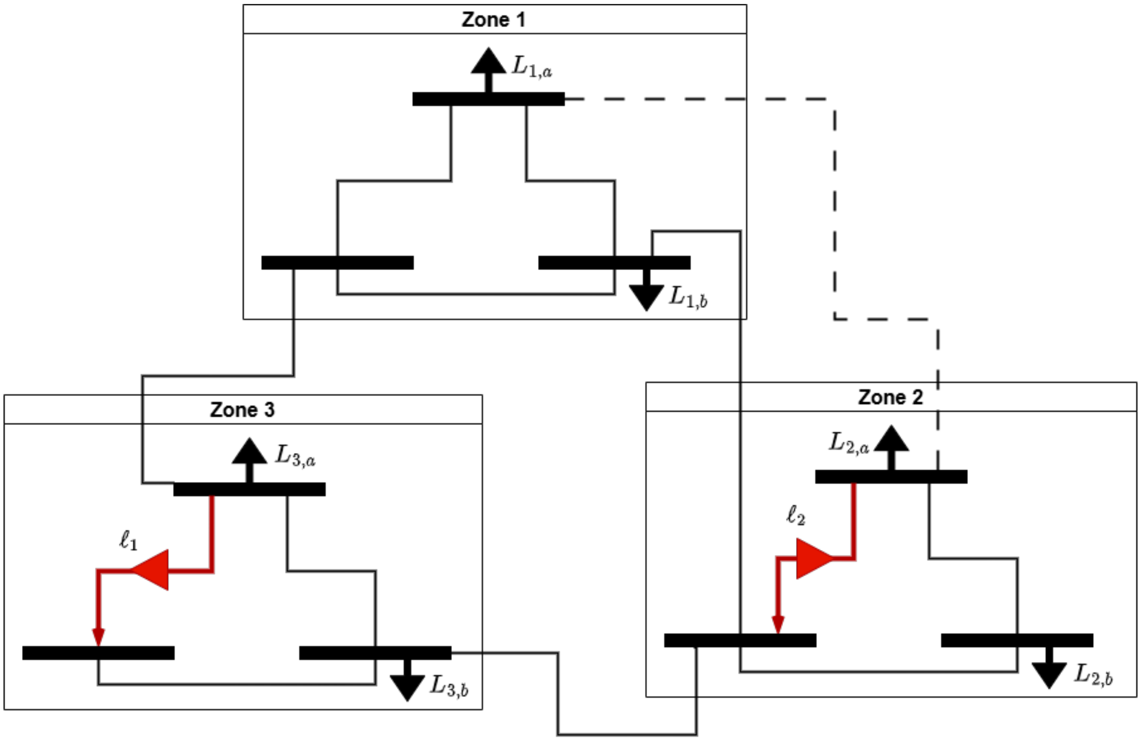

Figure 2: Sample case with thermal limit violations.

In Figure 2, the dashed line between Zone 2 and Zone 1 represents a project deactivation. During the power flow and contingency analysis violations on branches l_1 and l_2 are observed. The big arrowhead in the middle of the branches represents flow direction, while smaller arrowhead at the end of the branches represents the defined branch orientation. Therefore, $s_{l_1} = +1$ and $s_{l_2} = -1$ according to (4) (defined by from and to bus).

The desired system wide load reduction step is 1 MW.

Assume that $\epsilon_{l_2} = 0.1$ and $\epsilon_{l_2} = 0.05$ as defined in (3). Thus, *weighted violation*, w_l, of l_1 is 10/15 and of l_2 is 5/15. Therefore, the amount of load to be reduced with respect to the violation on each line is:

Branch	w_l	Reduction [MW]
l_1	$\frac{10}{15}$	$1\text{MW} \times \frac{10}{15} = 0.67\text{MW}$
l_2	$\frac{5}{15}$	$1\text{MW} \times \frac{5}{15} = 0.33\text{MW}$

Assume, the following PTDF values for the zones onto each violating branch

Branch\Zone	Zone 1	Zone 2	Zone 3
l_1	$\mathrm{PTDF}_{l_{1,1}} = -0.15$	$\mathrm{PTDF}_{l_{1,2}} = +0.1$	$\mathrm{PTDF}_{l_{1,3}} = -0.4$
l_2	$\mathrm{PTDF}_{l_{2,1}} = -0.06$	$\mathrm{PTDF}_{l_{2,2}} = +0.3$	$\mathrm{PTDF}_{l_{2,3}} = +0.2$

Note that due to directionality, for the violation on l_1 only Zones 1 and 3 should be reduced, while for the violation on l_2 only Zones 2 and 3 should be reduce. The total reduction in each zone can then be calculated as:

	Zone 1	Zone 2	Zone 3
l_1	$0.67 \times \frac{0.15}{0.15 + 0.4} = 0.1818$		$0.67 \times \frac{0.4}{0.15 + 0.4} = 0.4848$
l_2		$0.33 \times \frac{0.3}{0.3 + 0.2} = 0.2$	$0.33 \times \frac{0.2}{0.3 + 0.2} = 0.1333$
Total	**0.1818**	**0.2**	**0.6181**

Note that the sum remains 1 MW.

The load reduction is then distributed based on the load participation factors, α_j, to each individual load. For an example, consider Zone 1, and assume that the nominal loads are $L_{1,a} = 10\mathrm{MW}$ and $L_{1,b} = 5\mathrm{MW}$. The load reductions for each load can be calculated as:

	Participation Factor α_j	Zone 1
$L_{1,a}$	$\frac{10}{10+5} = \frac{2}{3}$	$0.1818 \times \frac{10}{10 + 15} = 0.1212$
$L_{1,b}$	$\frac{5}{10+5} = \frac{1}{3}$	$0.1818 \times \frac{5}{10 + 15} = 0.0606$
Total		**0.1818**

Appendix B – Transmission Driver Considerations

The rationale behind the approach detailed in Section 3.1 for assessing the impact of load reduction on reliability driven projects is straightforward: the methodology simply identifies the load reduction needed to alleviate the reliability issue. Whether load reduction is an appropriate measure for projects that are tagged as economically or policy driven merits a closer interrogation. It is important to consider that many projects usually have multiple drivers. The following considers the expected behavior of the proposed methodology if a project is *not* primarily motivated by reliability.

For policy-driven projects, it is necessary to assume that the transmission is not a goal on its own, but rather a way to realize some objective. To that end, the presence of a policy driven project should be coupled with some other operational change. Chapter 3.3 of CAISO's 2023-2024 Transmission Plan[1] states, "the policy assessment is geared towards capturing the impact of resource build-out on transmission infrastructure, identifying any required upgrades, and generating transmission input for use by the CPUC in the next cycle of portfolio development." Therefore, policy-driven transmission projects are in service of added generation. Since a power flow case comes with a fixed dispatch, the cases integrating the policy-driven projects should include a change in dispatch representing the policy resource goals that necessitated the given transmission. When the proposed methodology from Section 3.1 is carried out, two outcomes can arise:

1) *Load reductions help alleviate violations*. In this case, the methodology demonstrates that it is possible to meet the policy objective without the transmission addition but rather, with load reduction.

2) *One of the two edge cases are encountered*. In this case, the transmission is necessary, irrespective of load reduction, to support the dispatch change. An example from the CAISO 2023-2024 TPP is the Humboldt offshore wind interconnection. The offshore wind injection will overload the system if these projects are not put in place and no change in load will alter that, which is an example of edge case 2 (see Section 3.1.2).

The economically driven upgrades are developed based on a production cost model. The 2023-2024 TPP notes that, "The production cost modeling simulations focus primarily on the benefits of alleviating transmission congestion to reduce energy costs." Therefore, the cases that include these projects should reflect a dispatch that would otherwise be congested. As a result, it is unlikely that edge case 1—where no violations are observed after removing a transmission project—will be relevant in this case. Once again, when the proposed methodology is carried out, two outcomes are expected:

1) *Load reductions help alleviate violations*, demonstrating there is a marginal transmission avoided cost. In other words, the improved economic dispatch, enabled by the transmission project, can be realized in the same way without the transmission project, if the load were reduced.

2) *Violations are unaffected by load reduction (edge case 2)*. This would suggest that the congestion the proposed project alleviates is not dependent on the increased loads. An example might be something like the observed Path 26 congestion mentioned in Table 4.6-1 in the 2023-2024 TPP. The report states that, "The main driver of the Path 26

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[1] https://www.caiso.com/documents/iso-board-approved-2023-2024-transmission-plan.pdf

corridor congestion is the large amount of renewable generation and battery in Southern CA identified in the CPUC portfolio.” Since the proposed methodology maintains a constant injection pattern, load reduction will not alleviate the overgeneration and resulting congestion described in this scenario, and violations will persist.

These examples show that the proposed methodology should correctly discern the relevance of load reduction, even for projects that are categorized as policy driven or economically driven.

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