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PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

**PREPARED REBUTTAL TESTIMONY
ON
MARGINAL TRANSMISSION CAPACITY COSTS
IN
PACIFIC GAS AND ELECTRIC COMPANY'S
2023 GENERAL RATE CASE PHASE 2**

San Francisco, California
October 9, 2026

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CHAPTER 1 – MARGINAL TRANSMISSION CAPACITY COSTS

(Witness: Christopher Hogan)

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) rebuttal testimony in response to the marginal transmission capacity cost (MTCC) proposals from Pacific Gas and Electric Company's (PG&E) of \$63.61 per kilowatt-year (kW-year),¹ Solar Energy Industries Association (SEIA) of \$86.22 per kW-year,² and Agricultural Energy Consumers Association (AECA) of \$125 per megawatt hour (MWh).³

The Commission should adopt PG&E's MTCC calculation method and proposal, because it accurately categorizes which transmission projects are deferrable, accurately reflects the avoided cost value of deferring transmission capacity projects, and correctly uses a five-year input data horizon consistent with the Avoided Cost Calculator (ACC). The Commission should reject SEIA's MTCC proposal because a six-year input data horizon⁴ provides no additional benefits over PG&E's five-year horizon proposal, and it skews costs higher than a five-year horizon through the introduction of erroneous, rescope or deferred transmission project cost data into the MTCC calculation. Further, the Commission should reject AECA's MTCC proposal because AECA's proposal does

¹ A.24-09-014, *Pacific Gas and Electric Company 2023 General Rate Case Phase II Errata Testimony to April 18, 2025 Prepared Testimony Exhibit (PG&E-2) Cost of Service Studies (PG&E-2), Chapter 5: Marginal Transmission Capacity Costs* (Chapter 5), October 29, 2025, at 5-1, line 18-20.

² A.24-09-014, *Prepared Direct Testimony of R. Thomas Beach on Behalf of the Solar Energy Industries Association*, March 9, 2026 (SEIA Opening Testimony), at 25, lines 11-12.

³ A.24-09-014, *Direct Testimony of Richard McCann, PH.D. on Marginal Costs, Revenue Allocation, and Rate Design Issues on Behalf of the Agricultural Energy Consumers Association*, March 9, 2026 (AECA Opening Testimony), at 22, line 12, through 23 line 2.

⁴ SEIA Opening Testimony, at 25, lines 20-22.

not reflect the value of avoidable transmission capacity costs and thus does not meet the functional definition of an MTCC.⁵

II. DISCUSSION OF RECOMMENDATIONS

A. PG&E's Deferrability Criteria Results in an MTCC which Accurately Reflects Avoided Transmission Capacity Costs.

The Commission should adopt PG&E's proposed deferrability criteria for MTCC input data⁶ because it vastly improves upon the MTCC input data utilized for the adopted MTCC in PG&E's 2020 GRC II.⁷ Even though the MTCC adopted in PG&E's 2020 GRC II reflected SEIA's proposal in that previous proceeding,⁸ SEIA implicitly supports PG&E's proposed deferrability criteria in this 2023 GRC II proceeding.² Marginal costs reflect the cost of incremental infrastructure investments the utility can defer based on an incremental change in aggregate customer peak demand. In other words, if customers

⁵ See Appendix B, Attachment 1, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 48, 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, accessed June 9, 2026. (The 2024 ACC provides an MTCC description, "Transmission avoided capacity costs represent the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems. The paradigm is that reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects.")

⁶ PG&E-2, *Chapter 4: Deferrable Transmission Capacity Projects* (Chapter 4), Table 4-1: *2020 and 2023 GRC II Deferrability Criteria Mapping*, at 4-3.

⁷ Decision (D.) 21-11-016, *Decision Adopting Marginal Costs, Revenue Allocation, and Rate Designs for Pacific Gas and Electric Company*, November 19, 2021, Conclusion of Law 23, at 164 ("It is reasonable to adopt SEIA's proposed MTCC of \$52.45 per kW-year on the presumption that approximately 27 percent of PG&E's near-term planned transmission investments are related to capacity needs and therefore will be impacted by customer reductions in peak demand in response to marginal cost signals.").

⁸ D.21-11-016, Conclusion of Law 23, at 164 ("It is reasonable to adopt SEIA's proposed MTCC of \$52.45 per kW-year on the presumption that approximately 27 percent of PG&E's near-term planned transmission investments are related to capacity needs and therefore will be impacted by customer reductions in peak demand in response to marginal cost signals.").

² SEIA Opening Testimony, at 1 ("PG&E has made significant improvements in its method for calculating its MTCC. These include more reasonable criteria for determining which future transmission projects are capacity-related and a more extensive showing of how PG&E determines which projects qualify as deferrable according to these criteria. SEIA recommends one adjustment to PG&E's calculated MTCC – given the "lumpiness" of transmission additions, the MTCC calculation should look at deferrable transmission projects over the same six-year forward period used to assess MGCCs.").

1 unexpectedly increase their aggregate peak demand, the utility must make additional
2 infrastructure investments using ratepayer approved funds to increase the grid's capacity
3 to meet that increase in demand and maintain reliable service. In contrast, if customers
4 unexpectedly reduce their aggregate demand, the utility can defer the optional
5 infrastructure investments and corresponding cost.¹⁰ Therefore, the marginal cost value
6 reflects the deferrable, optional infrastructure investment costs from changes in aggregate
7 customer demand.

8 In contrast, if current transmission grid capacity is insufficient to meet customer
9 demand under normal operating conditions, the utility cannot reasonably avoid certain
10 infrastructure investments necessary to maintain grid reliability requirements unless
11 enormous and unlikely changes in customer demand occur. The MTCC calculation
12 should exclude transmission infrastructure investments the utility cannot reasonably
13 avoid. For example, if transmission grid capacity does not meet current federal
14 requirements to reduce the chance of an overload event or blackout with no change in
15 customer demand, a project intended to increase transmission capacity to meet the federal
16 reliability requirements should not be considered deferrable. In other words, the project's
17 cost does not reflect a marginal cost, because the only circumstance where the utility
18 would not be required to make the investment would be under the unlikely scenario of
19 enormous decreases in customer demand. The investment would be required to maintain
20 reliability even if load remained flat or decreased within a standard range. PG&E's
21 proposed deferability criteria provide a reasonable threshold for determining whether a
22 transmission capacity infrastructure investment categorization should fall under
23 deferrable or required.

¹⁰ This statement assumes sufficient transmission capacity to meet current customer demand.

1 **1. PG&E’s deferability criteria outlines which**
2 **transmission projects could be deferred based on**
3 **federal reliability standards.**

4 In this proceeding, PG&E reasonably expanded which transmission projects it
5 considers deferrable compared to its 2020 GRC II proposal. The proposed expansion
6 includes projects that increase transmission capacity that address capacity deficiencies
7 with a probability of less than 25%.¹¹ In contrast, PG&E previously proposed projects
8 which only address transmission capacity deficiencies with a probability of 10% or less
9 in PG&E’s 2020 GRC II.¹² PG&E supports its proposed expansion of the deferability
10 criteria by stating the 25% overload threshold selection is “where overloaded facilities
11 may begin to experience adverse operational effects, such as overheating and reduced
12 stability.”¹³ Further, the increased 25% overload threshold was developed using PG&E’s
13 “cascading outage risk assessment methodology,” which PG&E also uses to meet its
14 North American Electric Reliability Corporation (NERC)¹⁴ requirements.¹⁵ Lastly,
15 PG&E’s proposed 25% overload threshold falls toward the middle of the range where
16 PG&E asserts transmission line relays and transformers typically trigger thermal
17 protections (115% - 150%) depending on the overload time duration.¹⁶ Thus, PG&E’s
18 25% threshold for determining whether a transmission project can be deferred strikes a
19 reasonable balance between reliability and practicality.

¹¹ PG&E-2, Chapter 4, Table 4-1: *2020 and 2023 GRC II Deferability Criteria Mapping*, line 1, at 4-3.

¹² PG&E-2, Chapter 4, Table 4-1: *2020 and 2023 GRC II Deferability Criteria Mapping*, lines 1-2, at 4-3.

¹³ See Appendix B, Attachment 2, PG&E’s response to DR Cal Advocates-PG&E-013, question 1a, sent on January 17, 2025.

¹⁴ NERC is a not-for-profit, non-governmental entity to which the Federal Energy Regulatory Commission has delegated authority to create and enforce compliance with reliability standards, available at: <https://www.nerc.com/who-we-are>, accessed September 22, 2026.

¹⁵ See Appendix B, Attachment 2, PG&E’s response to DR Cal Advocates-PG&E-013, question 1b, sent on January 17, 2025.

¹⁶ See Appendix B, Attachment 3, PG&E’s response to DR Cal Advocates-PG&E-013, question 2, sent on January 17, 2025.

1 **2. Not all transmission capacity infrastructure**
2 **investments are deferrable.**

3 PG&E’s deferability criteria for incorporating input data into the MTCC results in
4 a more accurate avoided cost than including all capacity related transmission projects into
5 the MTCC.¹⁷ PG&E’s criteria excludes necessary transmission project costs to meet
6 reliability requirements under flat or even decreasing demand conditions, and costs that
7 are only avoidable if extreme and unlikely reductions in load occur. In this Application,
8 PG&E proposes to exclude these required transmission projects from the MTCC
9 calculation.¹⁸ First, PG&E specifically categorizes transmission projects that increase
10 capacity to mitigate current overload conditions and reduce the potential for blackouts
11 under current conditions or with one component failure as not deferrable.¹⁹ Second,
12 PG&E also categorizes transmission capacity projects intended to withstand or recover
13 from extreme events as not deferrable.²⁰ Lastly, PG&E proposes to consider transmission
14 projects intended to mitigate high voltage conditions due to reduced load at particular
15 hours of the day, and projects intended to manage fault currents that do not depend on
16 load growth as not deferrable.²¹

17 PG&E’s proposed method for categorizing and only including deferrable
18 transmission capacity projects in its MTCC aligns with the MTCC calculation formula
19 and with the Avoided Cost Calculator’s method for selecting transmission projects to be
20 included in its MTCC calculation. MTCC calculations include the Real Economic

¹⁷ D.21-11-016, at 67 (The MTCC method adopted by D.21-11-016 incorrectly considers all transmission project costs intended to increase transmission grid capacity as deferrable which does not hold up to scrutiny, because this method includes projects necessary to meet reliability requirements without changes in demand that cannot be deferred. In D.21-11-016, the Commission was unconvinced of PG&E’s arguments that “PG&E essentially argued that if a transmission project is related to reliability concerns or Commission mandates then it cannot be deferred, regardless of whether that reliability concern is tied to peak demand.”).

¹⁸ PG&E-2, Chapter 4, at 4-11, lines 15-21.

¹⁹ PG&E-2, Chapter 4, Table 4-1: *2020 and 2023 GRC II Deferability Criteria Mapping*, lines 1 and 9, at 4-3.

²⁰ PG&E-2, Chapter 4, Table 4-1: *2020 and 2023 GRC II Deferability Criteria Mapping*, lines 8, at 4-3.

²¹ PG&E-2, Chapter 4, Table 4-1: *2020 and 2023 GRC II Deferability Criteria Mapping*, lines 5, at 4-3.

1 Carrying Cost (RECC) factor as an input.²² Inclusion of the RECC factor results in an
2 MTCC which represents the annualized, avoided cost of deferring a transmission capacity
3 related project for one year.²³ PG&E’s categorization and inclusion of only deferrable
4 transmission capacity projects in its MTCC produces a meaningful MTCC that reflects
5 the avoided costs from deferring a transmission capacity project for one year due to a
6 change in customer demand. Mechanically, the RECC factor can be mathematically
7 applied to all transmission capacity costs (deferrable and not deferrable). However,
8 including unavoidable capacity related costs produces an overestimate of MTCC over the
9 “true” value, because the unavoidable costs are added in the numerator of the MTCC
10 equation.²⁴ Further, the resulting MTCC loses all practical meaning, because including
11 unavoidable costs in a measure tasked with representing avoidable costs presents a
12 contradiction. Effectively, this incorrect and inflated MTCC would represent the avoided
13 cost value of necessary and unavoidable transmission project costs.

14 The Commission should adopt PG&E’s proposed deferability criteria for
15 developing an MTCC, because the criteria isolates the projects that the utility could
16 actually defer, consistent with the ACC, thus producing a more accurate MTCC and
17 avoided cost value. In contradiction to the MTCC adopted in D.21-11-016, the MTCCs
18 adopted for Southern California Edison Company (SCE) and San Diego Gas & Electric

²² PG&E-2, Chapter 5, at 5-5, lines 14-16.

²³ See Appendix B, Attachment 4, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 86-87, 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, accessed June 9, 2026. (“The DTIM RECC annualizes the full unit cost of the projects over the life of the project (50-60 years) and reflects revenue requirement components (e.g., taxes) that increase the cost of the project to ratepayers. This is equivalent to value of deferring the revenue requirement cost of the project and all of the project’s future replacements by one year. his paradigm of the one-year replacement value is how the RECC was originally developed in the Electric Utility Rate Design Study Task Force 4 by NERA for EPRI (NP-22555).”)

²⁴ PG&E-2, Chapter 6: *Marginal Distribution Capacity Costs*, at 6-4, line 3. PG&E uses the same Discount Total Investment Method equations for marginal distribution capacity costs as MTCC. “I_t” in the equation reflects capital investment costs which are in the numerator of the DTIM and are thus directionally correlated with the resulting MTCC. In other words, adding transmission capacity related costs that are not deferrable to the deferrable capacity costs contained in “I_t” would increase the resulting MTCC.

1 Company (SDG&E) in the ACC only include reasonably deferrable transmission project
2 costs and exclude unavoidable transmission costs. Similar to PG&E’s deferability
3 proposal, the ACC consultant calculates MTCCs for SCE²⁵ and SDG&E²⁶ that only
4 include transmission capacity costs which can be reasonably avoided through distributed
5 energy resource (DER) adoption, because these results serve as an input to value DERs.²⁷
6 For example, in developing SDG&E’s MTCC for the 2024 ACC, the transmission project
7 cost input data consists only of “transmission projects determined by SDG&E to be
8 systemwide and potentially deferrable by DER.”²⁸ The ACC would significantly
9 overestimate the value of DERs if all transmission capacity projects were included in the
10 MTCC instead of only transmission capacity projects that can be avoided by DERs. For

²⁵ See Appendix B, Attachment 5, Rulemaking (R.) 22-11-013, *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards, Reply Comments of Southern California Edison Company (U 338-E) on the Proposed Decision Adopting Updates to the Avoided Cost Calculator*, August 25, 2026, at 4, footnote 20. SCE provides the transmission project cost input data that the ACC consultant uses to calculate SCE’s MTCC in the ACC based on which transmission projects in SCE’s service territory can be reasonably avoided by DERs (“From Energy Division’s 2026 ACC Transmission Data Request: “If the utility chooses to exclude projects that have peak load deficiencies that are too large to be deemed ‘deferrable’ by DER (or some other load reduction based exclusion criteria), data for those projects should be included separately in the data response to allow consideration of the impact of the inclusion or exclusion of such projects, as well as the appropriateness of excluding such projects from near term marginal costs but including for long term marginal costs.”).

²⁶ See Appendix B, Attachment 4, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 87, 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, accessed June 9, 2026. The consultant calculates SDG&E’s MTCC in the ACC using transmission project infrastructure investments that can only be reasonably avoided through DER adoption. (“Therefore, the DTIM method is applied to transmission projects determined by SDG&E to be systemwide and potentially deferrable by DER.”).

²⁷ See Appendix B, Attachment 6, *2026 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 5, available at <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a.pdf>, accessed September 18, 2026. (“The ACC is used to determine the benefits of Distributed Energy Resources (DER), such as energy efficiency and demand response, for cost-effectiveness analyses . . . The ACC calculates hourly system-level costs of providing electric or gas service for 30 years, in \$/kWh or \$/therm. These hourly avoided costs are used with specific program data, such as hourly energy savings, to determine program benefits.”).

²⁸ See Appendix B, Attachment 4, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 87, 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, accessed June 9, 2026.

1 instance, SCE asserted that the Wildlife substation project that was used for SCE's
2 MTCC in the 2024 ACC could not be avoided by DER adoption.²⁹ Subsequently, SCE's
3 MTCC in the 2026 ACC excludes the Wildlife substation project which resulted in a
4 more accurate MTCC for valuing DERs.³⁰

5 **B. SEIA's Proposed Six-Year Horizon is Inconsistent with**
6 **Commission Practices and Produces a Less Accurate**
7 **MTCC.**

8 The Commission should adopt a five-year input data horizon instead of SEIA's
9 proposed six-year horizon,³¹ because it provides the best estimate of transmission project
10 costs most likely recovered in rates during the four-year GRC II cycle and aligns with
11 current Commission practices.

12 **1. SEIA's proposed six-year input data horizon**
13 **introduces unnecessary variability into the**
14 **resulting MTCC.**

15 The Commission should reject SEIA's six-year MTCC horizon proposal³² because
16 a six-year horizon of forecasted transmission project data adds unnecessary variability
17 and uncertainty into the MTCC. Deferrable transmission projects are those projects that
18 could potentially be deferred. Thus, the time to completion and final cost may differ
19 greatly from the approval date,³³ and when the project completes. Including forecasted,
20 deferrable projects with completion dates more than five years out typically adds
21 unnecessary variability and potential inaccuracy in the MTCC estimate as shown in this

²⁹ See Appendix B, Attachment 7, R.22-11-013, *Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Issuing Updated 2023 Avoided Cost Calculator Staff Proposal for Party Input*, June 19, 2026, at 4.

³⁰ See Appendix B, Attachment 8, *2026 Distributed Energy Resources Avoided Cost Calculator Documentation*, Table 10-1: *SCE Project Costs and Load Forecast*, at 70, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a.pdf>, accessed September 18, 2026.

³¹ SEIA Opening Testimony, at 25, lines 20-22.

³² SEIA Opening Testimony, at 25, lines 20-22.

³³ The California Independent Service Operator (CAISO) board approves capacity related transmission projects in its annual Transmission Planning Process (TPP).

1 testimony. For example, SEIA’s proposed six-year time horizon incorporates the cost of
2 three more projects compared to PG&E’s five-year time horizon.³⁴ However, all three of
3 those projects were delayed or re-scoped, and the expected in-service dates now either
4 fall outside of SEIA’s proposed six-year time horizon or are no longer categorized as
5 deferrable.³⁵ Thus, the Commission should reject SEIA’s proposed six-year horizon,
6 because the additional year of data used for developing MTCC includes overly
7 speculative project costs.

8 In contrast, PG&E’s five-year input data horizon provides a near-term forecast of
9 transmission project costs with higher likelihoods for completion during the four-year
10 GRC II cycle. Further, a five-year time horizon provides an additional year of input data
11 over the four-year GRC II cycle that serves as a margin of error given the difficulty in
12 estimating the completion date for transmission projects. Thus, a five-year horizon
13 should be adopted, because it provides a more accurate near-term forecast of transmission
14 costs than SEIA’s proposed six-year horizon.

15 **2. SEIA’s proposed six-year input data horizon**
16 **results in an inflated MTCC while PG&E’s**
17 **proposal results in a comparable MTCC.**

18 As shown in Table 1-1, SEIA’s choice of a six-year input data horizon results in a
19 skewed MTCC value compared to other input data horizon choices. SEIA’s six-year
20 input data horizon proposal results in a significantly larger MTCC of \$86.22 compared to

³⁴ See Appendix B, Attachment 9, 2025-2026 Board Approved CAISO TPP, May 19, 2026, project 2223-R-18, at 171, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026. Redwood City Area 115 kV System Reinforcement project was delayed and now has an expected in-service date of February 2030. See Appendix B, Attachment 10, PG&E’s response to DR Cal Advocates-PG&E-032, question 1a, sent June 30, 2026. Coburn-Oil Fields 60 kV System project now has an expected in-service date of September 2031. See Appendix B, Attachment 11, PG&E’s response to DR Cal Advocates-PG&E-032, question 4, sent June 30, 2026. Morgan Hill Area Reinforcement project was re-scoped and PG&E now categorizes this project as required and not deferrable.

³⁵ PG&E-2, Chapter 4, Table 4-2: *Deferrable Transmission Capacity Projects*, line 2, line 14, and line 17, at 4-12 through 4-13. These were the only projects that had expected, 2029 in-service dates which serve as an input to SEIA’s MTCC proposal.

1 the \$66.00 MTCC produced based on a four-year horizon (as adopted in D.21-11-016),³⁶
2 and the \$63.61 MTCC produced by the five-year horizon which PG&E proposes and
3 aligns with the input horizon for the ACC.³⁷ If the Commission chooses to adopt an
4 MTCC with a longer input data horizon to ensure coverage until implementation of the
5 next GRC II decision, the \$62.35 MTCC produced by an eight-year horizon includes
6 transmission projects into PG&E's 2031 GRC II test year, and is far lower than SEIA's
7 MTCC proposal of \$86.22. In contrast, PG&E's five-year input data horizon proposal
8 results in a moderate, \$63.61 MTCC.

9 SEIA provides no evidence of additional benefits from its six-year horizon
10 proposal compared to PG&E's proposed five-year horizon and the Commission should
11 reject its proposal. SEIA only supports its six-year horizon proposal by stating it
12 accounts for the "lumpiness" in transmission investments but provides no evidence of the
13 deficiencies with a five-year horizon regarding investment "lumpiness."³⁸ Given
14 PG&E's five-year input data horizon produces an MTCC comparable to other input data
15 horizon choices, and SEIA's proposal produces an outlier compared to the other choices,
16 the Commission should adopt PG&E's proposed MTCC of \$63.61 per kW-year.

³⁶ D.21-11-016 at 66 ("SEIA recommended that the Commission adopt an MTCC value of \$52.45 per kW-year, by assuming that 27.26 percent of PG&E's 2021-2024 investments are capacity-related and are therefore marginal transmission costs.").

³⁷ See Section II.B.4 of this testimony.

³⁸ SEIA Opening, at 1.

Table 1-1: Illustrative MTCCs based on Input Data Horizon Length³⁹

Input Data Horizon (Years)	Resulting MTCC (\$ per kW-year)
4 (D.21-11-016 Adopted Input Data Horizon)	\$66.00
5 (PG&E's Proposal and ACC Horizon)	\$63.61
6 (SEIA's Proposal)	\$86.22
7 (2024-2030)	\$73.26
8 (2024-2031)	\$62.35

3. SEIA's basis for its proposed six-year input data horizon is factually incorrect.

In addition, SEIA supports its six-year time horizon by incorrectly asserting that “the four-year window for this case runs through 2029.”⁴⁰ SEIA correctly identifies that GRC II cycles typically last four years; however, PG&E's 2023 GRC II should theoretically cover the years 2023 (test year) through 2026.⁴¹ PG&E's 2023 GRC 2

³⁹ See confidential errata workpapers supporting PG&E-2, Chapter 5, “GRC-2023-PhII_WP_PGE_20250418_Ex02Ch05_MTCC_Model_PROP_CONF_ERRATA.” The length in years of the input data horizon can be inputted in tab “Dashboard,” cell E30. The corresponding MTCC output is provided in tab “OUT_MTCC_Results,” cell G12.

⁴⁰ SEIA Opening, at 25, lines 7-10.

⁴¹ See PG&E-1, *Overview and Guiding Policy Framework*, Chapter 1, *Overview and Guiding Policy Framework*, at 1, lines 9-12. The 2023 test year and 2024-2026 attrition years for PG&E's 2023 GRC cycle are confirmed in D.20-01-002, *Decision Adopting the Commission's Rate Case Plan for Energy Utilities, Appendix B: Schedule for the Transition from the Current Three-Year GRC Cycle to the Four-Year GRC Cycle*. PG&E confirms that this application is its 2023 GRC II filing.

1 proceeding is almost a full, four-year GRC II cycle delayed, because ideally a 2023 GRC
2 II decision should be issued by the end of 2022 for the decision to be effective starting
3 with the 2023 test year. PG&E's 2027 GRC II⁴² application, which should cover 2029, is
4 already past its filing requirement of August 2025.⁴³ PG&E's following 2031 GRC II
5 filing requirement of August 2029 would cover the years 2031 through 2034.⁴⁴
6 Regardless of whether PG&E will file a delayed 2027 GRC II application or whether the
7 Commission will direct PG&E to skip its 2027 GRC II filing requirement, the end date
8 for this GRC 2 cycle is not 2029 as SEIA asserts.

9 **4. PG&E's five-year horizon proposal aligns with the**
10 **Commission's Avoided Cost Calculator MTCC**
11 **while SEIA's six-year horizon does not.**

12 The Commission consistently adopts a five-year or less horizon for developing
13 MTCCs in the ACC. Between 2020 and 2026, there have been five adopted ACCs for
14 each of the three large investor-owned utilities (IOUs), for a total of 15 adopted ACCs.⁴⁵
15 The Commission only adopted an MTCC with a six-year horizon in three⁴⁶ out of fifteen

⁴² PG&E's 2027 GRC II cycle covers the years 2027 through 2030.

⁴³ D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities*, January 22, 2020, at 1. The Commission directs energy utilities to file their GRC I application on May 15th, two years prior to the test year. See also D.20-01-002, at 44, footnote 80. The Commission confirmed that GRC II application should be filed 90 days after the May 15th GRC I application filing, resulting in an August GRC II filing.

⁴⁴ An August 2029 filing date for PG&E's 2031 GRC II application filing is four years after PG&E's 2027 GRC II application filing date.

⁴⁵ There have been five adopted ACCs between 2020 and 2026 (2020, 2021, 2022, 2024 and 2026). Thus, 15 instances (15 = 3 x 5).

⁴⁶ The Commission used a six-year horizon for SDG&E's MTCC in the 2022 ACC, 2024 ACC, and 2026 ACC. See Appendix B, Attachment 12, *2022 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 92, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf>. Also see Appendix B, Attachment 4, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 87 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. Also see Appendix B, Attachment 13, *2026 Distributed Energy Resources Avoided Cost Calculator Documentation*, Table 10-4: *SDG&E Project Costs and Load Forecast*, at 72 available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a_20260921.pdf.

1 instances (~20%) between the 2020 ACC and 2026 ACC. It adopted an MTCC with a
2 five-year horizon or less in the remaining twelve instances (80%).⁴⁷

3 The Commission adopted a six-year horizon for SDG&E's MTCC in the ACC in
4 three instances,⁴⁸ but did not provide specific analysis to support its choice. The
5 instances in which the Commission adopted less than a five-year horizon for developing
6 SDG&E's and PG&E's MTCC were due to extenuating circumstances. The Commission
7 considered adopting the typical five-year horizon for SDG&E's MTCC in the 2020
8 ACC⁴⁹ and the 2021 ACC.⁵⁰ However, the Commission adopted a four-year horizon
9 instead due to load data incompatibility concerns.⁵¹ Similarly, the Commission presented
10 PG&E's MTCC with the typical five-year horizon in the 2022 ACC,⁵² and the 2024

⁴⁷ 80% = 100% - 20%.

⁴⁸ The 2022, 2024, and 2026 ACC.

⁴⁹ See Appendix B, Attachment 14, 2020 *ACC Workshop: Transmission and Distribution Avoided Capacity Costs Presentation Slides*, at 6, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/T&D%20Workshop.pdf, accessed September 23, 2026. SDG&E's MTCC horizon was shortened to four years in the 2020 and 2021 ACCs due to negative load growth in 2020 which requires exclusion from the MTCC calculation.

⁵⁰ See Appendix B, Attachment 15, 2021 *ACC Documentation v1b*, Table 19: *SDG&E Transmission capital forecast and IEPR forecast without DER (\$M and MW)*, at 52, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2021%20ACC%20Documentation%20v1b.pdf, accessed September 23, 2026. SDG&E's MTCC horizon was shortened to four years in the 2020 and 2021 ACCs due to negative load growth in 2020 which requires exclusion from the MTCC calculation.

⁵¹ See Appendix B, Attachment 14, 2020 *ACC Workshop: Transmission and Distribution Avoided Capacity Costs Presentation Slides*, at 6, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/T&D%20Workshop.pdf, accessed September 23, 2026. Also see Appendix B, Attachment 15, 2021 *ACC Documentation v1b*, Table 19. SDG&E Transmission capital forecast and IEPR forecast without DER (\$M and MW), at 52, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2021%20ACC%20Documentation%20v1b.pdf, accessed September 23, 2026. SDG&E's MTCC horizon was shortened to four years in the 2020 and 2021 ACCs due to negative load growth in 2020 which requires exclusion from the MTCC calculation.

⁵² See D.21-11-016 at 66. PG&E's MTCC adopted in D.21-11-016 and proposed by SEIA includes a 4-year horizon. See also Appendix B, Attachment 16, 2022 *Distributed Energy Resources Avoided Cost Calculator Documentation*, at 85, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf>. The 2022 ACC used PG&E's MTCC adopted in PG&E's 2020 GRC II.

1 ACC.⁵³ However, the Commission adopted a four-year horizon instead, because the
2 Commission adopted SEIA’s proposed MTCC with a four-year horizon in PG&E’s last
3 GRC II.⁵⁴ The ACC typically uses the MTCC adopted in PG&E’s GRC II proceedings,
4 thus the Commission should adopt an MTCC with a five-year horizon that aligns with the
5 ACC.

6 **C. The Commission Should Reject AECA’s MTCC Proposal**
7 **that Inaccurately Redefines the Purpose of MTCC.**

8 The Commission should reject AECA’s proposed MTCC of \$0.1246 per kilowatt
9 hour (kWh),⁵⁵ because it does not reflect the change in transmission costs based on a
10 change in customer demand. Instead, AECA’s invalid MTCC proposal reflects the
11 change in CAISO transmission revenue requirements for each unit of volumetric
12 generation additions.⁵⁶ The Commission should reflect AECA’s and Cal Advocates
13 concerns that neither demand nor transmission capacity projects drive the currently
14 increasing transmission revenue requirements by adopting PG&E’s lower MTCC
15 proposal of \$63.61 per kW-year.

⁵³ D.21-11-016 at 66. PG&E’s MTCC adopted in D.21-11-016 and proposed by SEIA includes a 4-year horizon. See Appendix B, Attachment 1, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 47-48, 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. The 2024 ACC used PG&E’s MTCC adopted in PG&E’s 2020 GRC II.

⁵⁴ D.21-11-016 at 66 (“SEIA recommended that the Commission adopt an MTCC value of \$52.45 per kW-year, by assuming that 27.26 percent of PG&E’s 2021-2024 investments are capacity-related and are therefore marginal transmission costs.”).

⁵⁵ AECA Opening Testimony at 23, lines 1-2.

⁵⁶ AECA Opening Testimony at 22, line 10, through 23, line 2 (“Using these two data sources, we calculated the incremental or marginal cost for transmission using the change in annual revenue requirements as a proxy for the direct cost. Figure AECA-11 shows how transmission revenue requirement increases relate to generation additions. Based on this analysis, the marginal cost of transmission is \$125 per megawatt-hour or \$0.1246 per kilowatt-hour.”).

1 **1. AECA’s proposed volumetric form for MTCC does**
2 **not reflect marginal transmission capacity costs.**

3 Previous ACC and PG&E GRC IIs MTCC values reflect the avoided capacity
4 investment cost resulting from reductions in customer demand.⁵⁷ AECA instead proposes
5 a new method of interpreting MTCC that reflects transmission costs on a volumetric basis
6 (kilowatt hours) instead of a capacity or demand basis (kilowatt-years).⁵⁸ AECA’s
7 proposed MTCC diverges from the purpose of an MTCC, because it does not reflect the
8 marginal cost of adding transmission capacity to meet customer demand increases.
9 Instead, AECA’s proposal reflects the change in revenue requirement for each unit of
10 volumetric generation additions.⁵⁹ However, the revenue requirement includes all costs,
11 including unavoidable fixed costs that do not change based on changes in electricity
12 demand.⁶⁰ For example, reductions in electricity usage would not reduce vegetation
13 management costs, because vegetation growth does not depend on customer usage.

14 In other words, mathematically converting AECA’s volumetric MTCC proposal to
15 kW-year units which actually reflect demand and capacity produces a meaningless
16 MTCC, because the underlying input data reflects all transmission costs, and does not
17 isolate capacity related transmission costs. AECA itself states that the generation costs

⁵⁷ See Appendix B, Attachment 1, *2024 Distributed Energy Resources Avoided Cost Calculator Documentation*, at 48, 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, accessed June 9, 2026. (“Transmission avoided capacity costs represent the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems. The paradigm is that reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects.”)

⁵⁸ AECA Opening Testimony at 23, lines 1-2.

⁵⁹ AECA Opening Testimony at 22, line 10, through 23, line 2 (“Using these two data sources, we calculated the incremental or marginal cost for transmission using the change in annual revenue requirements as a proxy for the direct cost. Figure AECA-11 shows how transmission revenue requirement increases relate to generation additions. Based on this analysis, the marginal cost of transmission is \$125 per megawatt-hour or \$0.1246 per kilowatt-hour.”).

⁶⁰ Such as wildfire mitigation, vegetation management, operations and maintenance such as the repair or replacement of transmission infrastructure.

1 that compose 90%⁶¹-100%⁶² of its Marginal Transmission **Capacity Cost** [emphasis
2 added] proposal serve the purpose of meeting “environmental compliance, not capacity
3 for reliability.”⁶³ The Commission should reject AECA’s proposed MTCC, because it
4 reflects unavoidable costs that do not increase transmission capacity to meet customer
5 demand, and thus does not reflect a true marginal transmission capacity cost.

6 **2. Generation interconnection costs should be**
7 **excluded from MTCC.**

8 AECA asserts that generation interconnection costs drive nearly **all** transmission
9 revenue requirement increases and includes these costs in its proposed MTCC.⁶⁴
10 However, MTCC estimates exclude generation costs, and MTCCs should continue to
11 exclude generation costs, because generation investments do not increase transmission
12 capacity.⁶⁵ MTCC is the transmission equivalent of marginal distribution capacity costs,

⁶¹ See Appendix B, Attachment 17, AECA’s response to DR Cal Advocates-AECA-002, question 2.a, sent April 8, 2026. (“AECA disagrees with PG&E’s analysis of what drives transmission investment. As shown in AECA’s testimony, it is renewable generation that explains at least 90% of marginal transmission investment.”). See also AECA Opening Testimony at 22, lines 7-9. AECA also asserts in testimony that 76% of generation interconnection costs could be due to renewable generation. (“And because 76% of the new generation is for renewable energy, not for peak reliability, kilowatt-hours of energy is the best metric.”)

⁶² See Appendix B, Attachment 17, AECA’s response to DR Cal Advocates-AECA-002, question 3.a, sent April 8, 2026 (“To clarify, AECA asserts that 100% of incremental transmission costs since at least 2012 are not capacity related. AECA demonstrates that the MTCC is entirely energy related because the CAISO peak load has not changed since 2012.”).

⁶³ AECA Opening Testimony, at 4, lines 10-15 (“Analysis of transmission costs and generation additions shows that at least 76% of marginal transmission costs are explained by new renewable generation over the period from 2012 to 2023. These costs should be assigned in the same manner as renewable energy costs to customer classes on a per kilowatt-hour basis because these investments have been made to deliver energy for environmental compliance, not capacity for reliability.”).

⁶⁴ See Appendix B, Attachment 17, AECA’s response to DR Cal Advocates-AECA-002, question 3.a, sent April 8, 2026 (“To clarify, AECA asserts that 100% of incremental transmission costs since at least 2012 are not capacity related. AECA demonstrates that the MTCC is entirely energy related because the CAISO peak load has not changed since 2012.”).

⁶⁵ D.25-08-049, *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, August 29, 2025, at 62 (“An IOU’s Marginal Transmission Capacity Costs, or MTCC represents the annualized cost per kilowatt to upgrade or expand transmission infrastructure to reliably transport an incremental unit of electricity, especially during peak demand periods. MTCC is typically

(continued on next page)

1 and reflects the “room” on the transmission system to **deliver** electricity to meet
2 increases in customer demand over a short time duration.⁶⁶ Delivery of electrons
3 excludes consideration of electron availability (generation) or whether generators are
4 even connected to the system. Generator interconnection costs provide generators access
5 to the transmission grid but does not ensure sufficient “room” on the transmission grid to
6 deliver electricity and meet the demand placed on the transmission system. For instance,
7 if a transmission line or substation has a maximum capacity of “X” megawatts (MW), the
8 maximum capacity of delivering “X” MW before an overload event occurs would remain
9 unchanged after interconnecting a new generator or even removing a generator. In other
10 words, a four-lane highway’s capability to serve four lanes of automobile traffic does not
11 change when only one car drives down the highway.

12 AECA’s proposal to include generation interconnection costs in MTCC also
13 conflicts with how the CAISO categorizes transmission costs. The CAISO categorizes
14 non-deferrable and potentially deferrable transmission projects which increase the
15 transmission grid capacity to meet customer demand as “reliability” costs.⁶⁷ The
16 CAISO’s reliability costs exclude transmission projects that repair or replace
17 transmission components on the grid.⁶⁸ The CAISO separately categorizes renewable

measured in dollars per kilowatt per year (\$/kW-year) and reflects the annualized investment required for augmenting the transmission system to deliver the highest forecasted loads to distribution networks without failure or significant losses.”).

⁶⁶ D.25-08-049, at 17 (“Marginal Transmission Capacity Cost (MTCC): the cost of expanding transmission infrastructure to **reliably transport** an incremental unit of electricity[emphasis added].”).

⁶⁷ See Appendix B, Attachment 18, 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 2, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026. (“Transmission projects are categorized as reliability-driven needed to serve load reliably and meeting NERC national standards; policy-driven needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.”)

⁶⁸ See Resolution E-5252, May 2, 2023, at 2, fn. 3 (“The CAISO’s FERC Tariff does not currently require review and approval of projects that do not expand the capacity of the CAISO-controlled transmission grid or which do so only incidentally.”).

interconnection costs as “policy” costs,⁶⁹ because these projects are intended to meet Renewables Portfolio Standard (RPS) policy targets.⁷⁰ The Commission should continue to exclude generation costs from MTCC, consistent with how the CAISO categorizes transmission costs.

3. “Self-approved” capital investments drive PG&E’s transmission capital expenditures and not generation costs, as AECA incorrectly asserts.

The basis for AECA’s MTCC proposal is AECA’s incorrect assertion that generation interconnection costs drive transmission revenue requirement increase.⁷¹ Although renewable generation interconnection once drove transmission revenue requirement increases,⁷² the Commission first noted in its 2021 Senate Bill 695 Report to the California legislature that “self-approved” utility transmission projects drove the majority (69%) of PG&E’s transmission capital infrastructure spending from the 2010

⁶⁹ See Appendix B, Attachment 18, 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 2, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026 (“Transmission projects are categorized as reliability-driven needed to serve load reliably and meeting NERC national standards; policy-driven needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.”).

⁷⁰ See Appendix B, Attachment 19, 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 21, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026 (“Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support local, state, and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California’s renewable energy goals.”).

⁷¹ See Appendix B, Attachment 17, AECA’s response to DR Cal Advocates-AECA-002, question 3.a, sent April 8, 2026 (“To clarify, AECA asserts that 100% of incremental transmission costs since at least 2012 are not capacity related. AECA demonstrates that the MTCC is entirely energy related because the CAISO peak load has not changed since 2012.”).

⁷² See Appendix B, Attachment 20, 2014 CPUC Assembly Bill 67 Report to the Legislature, *Electric and Gas Utility Cost Report: Public Utilities Code Section 747 Report to the Governor and Legislature*, April 2015, at 17, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/reports_and_white_papers/2014ab67final.pdf, accessed September 23, 2026 (“Transmission revenue requirements for the electric IOUs have been trending up since 2003. Much of the increase in the revenue requirements is due to additional transmission plant capital additions which have been built by the utilities. From 2004 – 2014, PG&E’s transmission revenue requirement has increased at a 12.15% annual average rate; SCE’s at a 22.5% annual average rate; and SDG&E’s at a 36.6% annual average rate. These increases are driven primarily by CAISO reliability and RPS mandates.”).

1 through 2019.⁷³ Further, PG&E reported in its public, May 2026 Transmission Process
2 Review filing that between 2021 through 2025, self-approved transmission projects alone
3 composed 76%-88% of its **annual** transmission capital expenditures,⁷⁴ and generation
4 interconnection only composed an additional 3%-11% of annual capital expenditures.⁷⁵
5 However, neither generation⁷⁶ or “self-approved”⁷⁷ transmission project costs increase
6 transmission capacity, and these costs should be excluded from the MTCC.

⁷³ See Appendix B, Attachment 21, 2021 CPUC Senate Bill 695 Report to the Legislature, *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1*, May 2021, Table 12: *CAISO-approved and Utility Self-approved Projects 2010-2019 (\$000)*, at 41, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf, accessed September 23, 2026.

⁷⁴ See *Public-PGE May 2026 Transmission Project Review Process Project Spreadsheet*, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transmission-project-review-process/pge/public-pge-may-2026-tp-r-project-spreadsheet.xlsx>, accessed September 21, 2026. PG&E Self-Approved project costs are designated with a value of “TRUE” in column 30 (excel column “AO”). Actual, annual capital expenditures are provided in column 57 (excel columns BU through “BY”). PG&E’s percentage of annual transmission capital expenditures spent on self-approved projects were derived from dividing the sum of capital expenditures for projects that were designated as self-approved pursuant to a “TRUE” value in column 30, divided by the total annual capital expenditures. Between ~0.05% and 0.5% of PG&E’s annual, “self-approved” transmission capital investments between 2021 through 2025 included “Generation Interconnection” or “Policy costs.”

⁷⁵ See *Public-PGE May 2026 Transmission Project Review Process Project Spreadsheet*, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transmission-project-review-process/pge/public-pge-may-2026-tp-r-project-spreadsheet.xlsx>, accessed September 21, 2026. Incremental generation interconnection projects that are not self-approved are designated with a value of “Generator Interconnection” and “Policy” in column 9 (excel column L), and a value of “FALSE” in column 30 (excel column “AO”). These incremental generation interconnection projects estimates exclude the negligible amount of “self-approved” transmission capital investments between 2021 through 2025 included “Generation Interconnection” or “Policy costs.”

⁷⁶ D.25-08-049, *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, August 29, 2025, at 62. (“An IOU’s Marginal Transmission Capacity Costs, or MTCC represents the annualized cost per kilowatt to upgrade or expand transmission infrastructure to reliably transport an incremental unit of electricity, especially during peak demand periods. MTCC is typically measured in dollars per kilowatt per year (\$/kW-year) and reflects the annualized investment required for augmenting the transmission system to deliver the highest forecasted loads to distribution networks without failure or significant losses.”)

⁷⁷ See Appendix B, Attachment 21, 2021 CPUC Senate Bill 695 Report to the Legislature, *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1*, May 2021, at 41 (“Projects that expand the capacity of the transmission grid are included in CAISO’s annual Transmission Planning Process (TPP), pursuant to

(continued on next page)

1 The data showing transmission costs unrelated to capacity increases drive nearly
2 all of the transmission capital expenditure, instead of load increases, supports a lower
3 MTCC such as PG&E’s proposed MTCC of \$63.61 per kW-year. For comparative
4 purposes, PG&E estimates its \$63.61 per kW-year MTCC reflects the costs from
5 approximately 14.4% of PG&E’s transmission projects from 2024-2028⁷⁸ which more
6 appropriately aligns with the transmission capital expenditure to meet capacity increases.
7 AECA’s concerns that transmission capacity increases do not drive new transmission
8 projects for PG&E should be reflected through adoption of PG&E’s lower MTCC
9 proposal of \$63.61 compared to SEIA’s MTCC proposal.

10 **III. CONCLUSION**

11 The Commission should adopt PG&E’s proposed MTCC value of \$63.61 per kW-
12 year, which reasonably categorizes which transmission capacity projects can be deferred,
13 utilizes a five-year input data horizon consistent with the ACC and excludes overly
14 speculative transmission project costs, and accurately reflects the cost of meeting
15 incremental transmission demand. Further, the Commission should reject SEIA’s \$86.22
16 per kW-year MTCC proposal, because its proposed six-year horizon adds erroneous
17 transmission project cost input data into the MTCC. The Commission should also reject
18 AECA’s irrelevant \$125 per MWh MTCC, because it does not reflect marginal
19 transmission capacity costs. For these reasons, the Commission should adopt Cal
20 Advocates’ recommendations.

requirements of FERC Order No. 890 (‘Order 890’), which requires transparent transmission planning. However, a majority of the California IOUs’ spending on capital additions is not related to grid capacity expansion and therefore receives no review by the CAISO through the TPP. FERC has determined that Order 890 does not apply to projects that do not expand the capacity of the transmission grid. These projects that are outside of the scope of the TPP are referred to as ‘self approved.’”).

⁷⁸ *PG&E-2*, Chapter 5, at 5-4, fn. 9.

APPENDIX A

QUALIFICATION OF WITNESSES

**PREPARED TESTIMONY
OF
CHRISTOPHER HOGAN**

Q.1 Please state your name and address.

A.1 My name is Christopher Hogan, and my business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the Public Advocates Office at the California Public Utilities Commission and my job title is Public Utilities Regulatory Analyst.

Q.3 Please describe your educational and professional experience.

A.3 I graduated from California State University East Bay, in Hayward California with a Master of Science degree in Statistics and a Bachelor of Science degree in Statistics and Economics. I have been employed by Cal Advocates for more than nine years. In my experience at Cal Advocates, I have submitted testimony and participated in Southern California Edison Company's (SCE) 2025 General Rate Case Phase II Application (A. 24-03-019), San Diego Gas & Electric Company's (SDG&E) 2024 GRC II Application (A. 23-01-008), SCE's 2021 GRC II (A. 20-10-012), Pacific Gas and Electric Company's (PG&E) 2020 GRC II (A.19-11-019), SDG&E's 2019 GRC II (A.19-03-002), Phase 2A of PG&E's and SCE's 2018 Rate Design Window Proceeding (consolidated as A.17-12-011), and SCE's 2018 GRC II (A.17-06-030).

Q.4 What is your area of responsibility in this proceeding?

A.4 My area of responsibility in this proceeding is focused on the Marginal Transmission Capacity Costs, and Cost Recovery, Nonmarginal Costs, and Export Compensation for the Real Time Pricing Track in this proceeding.

Q.5 Does that complete your prepared testimony?

A.5 Yes

APPENDIX B

SUPPORTING MATERIALS

TABLE OF ATTACHMENTS FOR APPENDIX B

Attachment	Description	Page
1	2024 ACC Documentation, at 47-48, excerpt	B-1
2	PG&E's response to DR Cal Advocates-PG&E-013, question 1, sent on January 17, 2025	B-3
3	PG&E's response to DR Cal Advocates-PG&E-013, question 2, sent on January 17, 2025	B-5
4	2024 ACC Documentation, at 86-87	B-7
5	R.22-11-013, <i>Reply Comments of Southern California Edison Company (U 338-E) on the Proposed Decision Adopting Updates to the Avoided Cost Calculator</i> , August 25, 2026, at 4, fn. 20, excerpt.	B-9
6	2026 ACC Documentation, at 5, excerpt	B-10
7	R.22-11-013, <i>Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Issuing Updated 2023 Avoided Cost Calculator Staff Proposal for Party Input</i> , June 19, 2026, at 4, excerpt	B-11
8	2026 ACC Documentation, at 70, excerpt. ⁷⁹	B-12
9	2025-2026 Board Approved CAISO TPP, at 171, excerpt	B-13
10	PG&E's response to DR Cal Advocates-PG&E-032, question 1, sent June 30, 2026	B-14
11	PG&E's response to DR Cal Advocates-PG&E-032, question 4, sent June 30, 2026.	B-16
12	2022 ACC Documentation, at 92, excerpt.	B-18

⁷⁹ 2026 Distributed Energy Resources Avoided Cost Calculator Documentation, Table 10-1: SCE Project Costs and Load Forecast, at 70, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a.pdf>, accessed September 18, 2026.

13	2026 ACC Documentation, at 72, excerpt	B-19
14	2020 <i>ACC Workshop: Transmission and Distribution Avoided Capacity Costs Presentation Slides</i> , at 6.	B-20
15	2021 ACC Documentation, at 6, excerpt	B-21
16	2022 ACC Documentation, at 85, excerpt	B-22
17	AECA's response to DR Cal Advocates-AECA-002, sent April 8, 2026	B-23
18	2025-2026 CAISO Board Approved TPP, at 2, excerpt. ⁸⁰	B-30
19	2025-2026 CAISO Board Approved TPP, at 21, excerpt. ⁸¹	B-31
20	2014 CPUC Assembly Bill 67 Report to the Legislature, at 17, excerpt	B-32
21	2021 CPUC Senate Bill 695 Report to the Legislature, at 41, excerpt	B-33

⁸⁰ 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 2, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026.

⁸¹ 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 21, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026.

Attachment 1: 2024 ACC Documentation, at 47-48, excerpt.⁸²

CPUC 2024 ACC Documentation

Figure 5-13: 2035 Expected Unserved Energy [MWh] from SERVIM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																	0.8	3.7	3.7	3.7	3.7	3.7	3.7	3.5
8	0.1														10.1	14.5	59.5	79.2	81.3	84.6	84.3	84.4	84.4	82.0
9	2.0	0.1				0.2	0.2	0.2	0.2		0.5	0.5	1.0	5.2	6.8	58.4	96.8	115	125	133	133	134	90.6	89.6
10																								
11																								
12																								

Figure 5-14: 2040 Expected Unserved Energy [MWh] from SERVIM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7	4.3	0.0												0.2	0.4	2.8	5.4	11.0	15.4	17.2	16.6	16.0	17.0	16.1
8	2.1												0.4	2.8	4.8	11.8	32.4	55.8	60.2	66.0	63.2	51.8	47.7	42.3
9	31.4	0.1					0.1						0.1	0.3	1.0	7.3	29.2	47.6	52.5	58.2	58.5	48.5	44.6	42.9
10																								
11																								
12																								

These month/hour EUE values were then allocated to days of the year using the CTZ22 temperature data and the 2018 calendar year for consistency with energy prices. A load-weighted daily maximum statewide temperature is calculated and all hours in days where the temperature exceeds a threshold receive the corresponding month/hour EUE value from SERVIM. The temperature threshold was calculated as one standard deviation below the highest temperature, resulting in a temperature threshold of 87 F. The allocation factors between modelled years are interpolated. Years before 2026 use 2026 allocation factors, and years after 2040 use 2040 allocation factors.

6 Transmission Avoided Capacity Costs

6.1 Background

The 2024 ACC update relies on the same general methodology as was used for the 2022 ACC to calculate transmission avoided costs for SCE and SDG&E. Changes made to improve consistency between utilities and incorporate updates to utilities' project data are noted in section 12.3. For PG&E, the transmission avoided cost value remains unchanged from the 2022 ACC update except for escalation adjustments. Though PG&E estimates transmission avoided costs in its GRC filings, the value used in the 2022 and 2024 ACC updates reflects an avoided cost value proposed by the Solar Energy Industries Association and adopted by the CPUC

⁸² 2024 Distributed Energy Resources Avoided Cost Calculator Documentation, at 47-48, 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, accessed June 9, 2026.

in its D.21-11-016 ruling. Transmission avoided costs for SCE and SDG&E are calculated using the Discounted Total Investment Method (DTIM) for system-wide projects and Locational Net Benefits Analysis (LNBA) for individual large projects. Inputs are provided by each utility in response to individual data requests. The final values for all three utilities are listed in Table .

Transmission avoided capacity costs represent the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems. The paradigm is that reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects. The ability to defer or avoid transmission projects would depend on multiple factors, such as the ability to obtain sufficient dependable aggregate peak reductions in time to allow prudent deferral or avoidance of the project, as well as the location of those peak reductions in the correct areas within the system to provide the necessary reductions in network flows.

This avoided cost update does not look to evaluate whether any particular technology, measure, or installation could provide transmission avoided cost savings. Those determinations should be made in the proceedings in which these avoided costs are applied. The values developed herein represent the value provided IF the peak loading reductions can be obtained in the right amount, right location, and with the right dependability.

It should also be noted that the locations of the needs for demand reductions or distributed generation or storage will move over time as loadings on the utility systems evolve differently in different areas within the utility service territories. Thus, over the next ten years there could be a value to load reductions in area A, but not area B; but in years 10-20 the situation may flip, and area B could become the area with a need for load reductions, while area A no longer has a need. Given this locational and temporal uncertainty, the transmission avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, the consultant believes that this approach is superior to trying to forecast locational needs far into the future. Details on the calculation of the utility-specific transmission costs are included in Appendix 12.3.

Table 6-1. Long-Term Transmission Marginal Costs (\$2023)

	PG&E	SCE	SDG&E
Transmission Capacity (\$/kW-yr.)	\$53.21	\$49.95	\$39.64

6.2 Annual Transmission Marginal Capacity Costs

The transmission capacity marginal costs are escalated to nominal dollars using the annual transmission escalation rates shown below. The escalation rates were provided by the utilities in their responses to the Energy Division data request for the 2024 ACC update. Values for all three utilities have decreased from the 2022 ACC update. The utilities noted that escalation rates used in transmission planning may vary annually or by project based upon the forecast conducted during project planning. The values in Table 6-2 are an average across years in the near-term transmission planning horizon.

Attachment 2: PG&E’s response to DR Cal Advocates-PG&E-013, question 1, sent on January 17, 2025.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalAdvocates_013-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_013-Q001Supp01
Request Date:	January 17, 2025
Requester DR No.:	013
Requesting Party:	Public Advocates Office
Requester:	Nathan Chau, James Lau, Christopher Hogan, Kimiko Akiya
Date Sent:	February 11, 2025
PG&E Witness(es):	Marco Rios – Electric Engineering

SUBJECT: DEFERABLE TRANSMISSION PROJECTS

QUESTION 001

PG&E’s testimony discusses its proposal to increase the capacity deficiency threshold to 25% to determine whether a transmission project is deferrable.¹ PG&E supports this proposal by stating PG&E uses the 25% threshold for its cascading analysis in its annual transmission reliability assessment.

- a. How did PG&E determine a 25% threshold is appropriate in its annual transmission reliability assessment? Please provide any supporting information and documentation.
- b. Is the 25% threshold specifically required by the North American Electric Reliability Corporation (NERC)?
 - i. If so, please provide a citation to the NERC requirement for using a 25% threshold.

ANSWER 001

- a. PG&E selected the 25% capacity deficiency threshold for identifying deferrable transmission projects based on its cascading outage risk assessment methodology. The PG&E cascading methodology used in its annual assessment has more detailed criteria and thresholds based on the voltage level and the asset type. Please refer to the “PG&E 2023 Electric Transmission Reliability Assessment Study Report”, section 2.3.2 for detailed information on the cascading methodology. The 25% overload threshold for deferrability criteria was selected as a practical and conservative threshold where overloaded facilities may begin to experience adverse operational effects, such as overheating and reduced stability. It also aims to ensure

¹ *Pacific Gas and Electric Company 2023 General Rate Case Phase II Prepared Testimony Exhibit PG&E-2 Cost of Service Studies (PG&E-2), Chapter 4: Deferrable Transmission Capacity Projects (Chapter 4) at 4-8.*

a balance between system reliability and deferral feasibility. Using this threshold allows PG&E to differentiate between projects that can be safely deferred and those where deferral could pose a significant risk of equipment damage and increased likelihood of cascading outages.

The PG&E 2024 Electric Transmission Reliability Assessment Study Report requires confidentiality review and will be provided in a supplemental response.

- b. The 25% threshold is not explicitly required by NERC. However, NERC reliability standards, particularly TPL-001-5 (Transmission System Planning Performance Requirements), provide a framework for evaluating overload conditions and cascading risks.

Key relevant NERC standard include:

- TPL-001-5 (Transmission System Planning Performance Requirements), which requires utilities to evaluate potential reliability risks, including the possibility of cascading failures. (TPL-001-5, R3, R4)²

While NERC does not mandate a 25% threshold, PG&E selected this value as a reasonable and conservative benchmark based on its planning methodology.

SUPPLEMENTAL ANSWER 001

Please see *GRC-2023-Phil_DR_CalAdvocates_013-Q001Supp01_Atch01.pdf* that provides the excerpt from PG&E's 2023 Electric Transmission Reliability Assessment Study Report describing PG&E's cascading methodology in support PG&E's response to Question 001 (a).

² TPL-001-5, NERC Transmission System Planning Performance Requirements, <https://nerc.com/pa/Stand/ReliabilityStandards/TPL-001-5.pdf> (as of February 6, 2025).

Attachment 3: PG&E’s response to DR Cal Advocates-PG&E-013, question 2, sent on January 17, 2025.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalAdvocates_013-Q002
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_013-Q002
Request Date:	January 17, 2025
Requester DR No.:	013
Requesting Party:	Public Advocates Office
Requester:	Nathan Chau, James Lau, Christopher Hogan, Kimiko Akiya
Date Sent:	February 6, 2025
PG&E Witness(es):	Marco Rios – Electric Engineering

SUBJECT: DEFERABLE TRANSMISSION PROJECTS

QUESTION 002

PG&E’s testimony states that overloads exceeding 25% can trigger the automatic action of protection devices in the system that can cause cascading outages.¹

- a. Is the 25% threshold the minimum threshold that can trigger automatic protection devices?
 - i. If not, what is the minimum percentage threshold that may trigger protection devices?

ANSWER 002

a. The 25% threshold is not necessarily the absolute minimum that can trigger automatic protection devices. The specific triggering threshold depends on several factors, including:

- Type of protection scheme – Different protective relays have different settings and time-delay characteristics.
- Equipment-specific thermal limits – Transformers, lines, and other components have distinct overload capabilities before tripping.
- Relay coordination settings – Protection schemes are designed to trip based on time-dependent and instantaneous settings to minimize unintended outages.

In PG&E’s system, the minimum threshold for triggering protection devices varies by asset type and protection scheme.

¹ PG&E-2, Chapter 4 at 4-8.

i. The exact minimum overload threshold that can trigger protection devices depends on relay settings and the type of facility. However, typical industry protection settings include:

- Transmission line relays:
 - Line relays may be set to trip at 115%–150% based on loading duration².
- Transformer overload protection:
 - Transformer protection schemes typically allow temporary overloads between 115% of the highest operator established emergency transformer rating and 150% of the applicable maximum transformer nameplate rating before triggering thermal protection³.

Thus, while some protection schemes may activate at lower overload levels, PG&E selected 25% as a practical and conservative threshold where cascading risk becomes a concern.

² NERC PRC-023-5-Transmission Relay Loadability, https://www.nerc.com/pa/Stand/Project/201509/201509-Establish-and-Communicate-System-Op/2015-09_PRC-023-5-clean.pdf (as of February 6, 2025).

³ *Id.*

Attachment 4: 2024 ACC Documentation, at 86-87, excerpt.⁸³

CPUC 2024 ACC Documentation

Table 12-7. Derivation of SCE Transmission Capacity Costs for Alberhill and Wildlife Projects using the LNBA Method (values in 2023\$)

Alberhill Project Cost (LNBA Method for large projects)				
1	Discount Rate	7.0085%		
2	Inflation Rate	1.99%		
3	Real Discount Rate	4.92%	$(1+1)/(1+2) - 1$	
4	Planning Horizon (yrs)	10		
5	RECC (For LNBA method)	12.30%	$((1+2)/(1+1))^4 / (((1+1)^4 - 1) / ((1+2)^4 - 1))$	
Year	Project Cost (\$M)	Peak Demand Growth (MW)	1 Yr Deferral Value (\$M)	Deferral Value (\$/kW)
2023	1.101	12	0.05	4.30
2024	1.572	11	0.07	6.70
2025	1.048	23	0.05	2.14
2026	17.117	19	0.80	42.25
2027	73.95	11	3.47	315.28
2028		9	0.00	0.00
2029		13	0.00	0.00
2030		11	0.00	0.00
2031		16	0.00	0.00
NPV using Real Discount Rate [NPV([3] [All Deferral Values above])]			3.55	294.87
RECC (From Above) [5]				12.3%
Present Value Revenue Requirement Factor				1.56
LNBA Value (\$/kW-yr) [15 (full deferral value)] * [16] * [17]				\$56.56
A&G (1.40%) * [18]				1.40%
General Plant (2.07%) * [18]				2.07%
Franchise Fees (1.79%) * ([18] + [19] + [20])				1.79%
Total Project Marginal Cost (\$/kW-yr) [18] + [19] + [20] + [21]				\$59.57
Percent of system load				4.375%
Project Marginal Cost spread across the system [22] * [23]				\$2.61
Wildlife Project Cost (LNBA Method for large projects)				
1	Discount Rate	7.0085%		
2	Inflation Rate	1.99%		
3	Real Discount Rate	4.92%	$(1+1)/(1+2) - 1$	
4	Planning Horizon (yrs)	10		
5	RECC (For LNBA method)	12.30%	$((1+2)/(1+1))^4 / (((1+1)^4 - 1) / ((1+2)^4 - 1))$	
Year	Project Cost (\$M)	Peak Demand Growth (MW)	1 Yr Deferral Value (\$M)	Deferral Value (\$/kW)
2023	0.9	1	0.04	42.21
2024	0.9	2	0.04	21.10
2025	75.198	2	3.53	1763.32
2026	212.832	2	9.98	4990.71
2027	61.133	4	2.87	716.76
2028		7	0.00	0.00
2029		0	0.00	0.00
2030		0	0.00	0.00
2031		0	0.00	0.00
NPV using Real Discount Rate [NPV([3] [All Deferral Values above])]			13.82	6268.13
RECC (From Above) [5]				12.3%
Present Value Revenue Requirement Factor				1.56
LNBA Value (\$/kW-yr) [15 (full deferral value)] * [16] * [17]				\$1,202.29
A&G (1.40%) * [18]				1.40%
General Plant (2.07%) * [18]				2.07%
Franchise Fees (1.79%) * ([18] + [19] + [20])				1.79%
Total Project Marginal Cost (\$/kW-yr) [18] + [19] + [20] + [21]				\$1,266.28
Percent of system load				2.445%
Project Marginal Cost spread across the system [22] * [23]				\$30.96

Note that the RECC factor used in the LNBA method is different from the RECC factor used in the DTIM method above. The DTIM RECC annualizes the full unit cost of the projects over the life of the project (50-60 years) and reflects revenue requirement components (e.g., taxes) that increase the cost of the project

⁸³ 2024 Distributed Energy Resources Avoided Cost Calculator Documentation, at 86-87, 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, accessed June 9, 2026.

to ratepayers. This is equivalent to value of deferring the revenue requirement cost of the project and all of the project's future replacements by one year. This paradigm of the one-year replacement value is how the RECC was originally developed in the Electric Utility Rate Design Study Task Force 4 by NERA for EPRI (NP-22555). The LNBA method follows this same deferral concept, but directly calculates the value of deferring projects over each year over the planning horizon. Because the LNBA method sums the deferral value of projects over multiple years, a RECC is used to convert that multi-year value back to a \$/kW-yr value needed for marginal costing. The RECC used for the LNBA method annualizes the total deferral value over the planning horizon (10 years) and does not include the Present Value Revenue Requirement Factor effects. For the LNBA, the RECC is utilized as a capital recovery factor that is constant in real dollars. A typo in the RECC equation listed in the 2021 and 2022 ACC external documentation is corrected here. This typo did not affect the RECC calculation itself for prior cycles, only what was described in the documentation.

Table 12-8. Total SCE Transmission Marginal Cost (\$/kW-yr 2023\$)

	Marginal Cost (\$/kW-yr)
System-wide projects	\$13.80 / kW-yr
Alberhill project averaged over SCE system	\$2.61 / kW-yr
Wildlife project averaged over SCE system	\$30.96 / kW-yr
Transmission O&M	\$ 2.58 / kW-yr
Total	\$49.95 / kW-yr

Transmission O&M is from SCE's 2024 Data Request Response

12.3.3 SDG&E

Similar to SCE, SDG&E does not provide estimates of transmission capacity costs in its GRC proceedings. Therefore, the DTIM method is applied to transmission projects determined by SDG&E to be systemwide and potentially deferrable by DER. The derivation method for the Marginal Transmission Capacity Cost as displayed in Table is the same as that applied for SCE, including the same modification to take the median load growth over an extended forecast period. The primary difference in data between the two utilities is that SDG&E includes 6 years in its planning horizon rather than the 5 of SCE, so all 6 years are included. This is consistent with the prior ACCs. The calculation of the SDG&E Transmission Annual MC Factor for the 2024 ACC cycle includes updated inputs provided by SDG&E in response to Energy Division data requests.

Attachment 5: R.22-11-013, *Reply Comments of Southern California Edison Company (U 338-E) on the Proposed Decision Adopting Updates to the Avoided Cost Calculator*, August 25, 2026, at 4, fn. 20, excerpt.

III. TRANSMISSION COSTS

Both SEIA and PCF criticize the process for selecting transmission projects to include in the calculation of Investor-Owned Utility (IOU) marginal transmission costs.¹⁸ SEIA proposes that the Commission adopt a methodology that would be used uniformly by all IOUs for the selection of these transmission projects.¹⁹ However, SEIA did not describe a substantive methodology in its comments on the PD or in prior comments. This proceeding lacks sufficient record for SEIA’s proposal to be considered.

To be clear, SCE does not select which transmission projects to include in these calculations in a vacuum or in an ad hoc manner. Each update cycle, the Commission’s Energy Division sends SCE a data request with instructions on which transmission projects to include in the response to the data request. Those instructions have been consistent—at least since the 2022 update cycle—if not earlier. The instructions also direct IOUs to separately list transmission projects and costs that the IOUs may have used judgment in excluding so that the “appropriateness of excluding such projects” can be considered.²⁰

Concerning the PD’s proposal to cease the use of the Locational Net Benefits Analysis (LNBA) methodology for marginal transmission costs, PCF states that “SCE identifies no projects to which the LNBA method will apply in 2026.”²¹ PCF cites the PD, which states “SCE also writes that it expects the one remaining LNBA transmission project to shift to the DTIM for 2026.”²² These statements seem to misinterpret SCE’s comments on the Revised Staff Proposal,²³ potentially concluding incorrectly that the elimination of the LNBA would have no practical effect for the 2026 ACC. To clarify, without a policy change, SCE would have one project, the Alberhill Substation, to which the LNBA would still apply for the 2026 ACC. If the

¹⁸ SEIA Comments, p. 4; PCF Comments, p. 3.

¹⁹ SEIA Comments, pp.4-5.

²⁰ From Energy Division’s 2026 ACC Transmission Data Request: “If the utility chooses to exclude projects that have peak load deficiencies that are too large to be deemed ‘deferrable’ by DER (or some other load reduction based exclusion criteria), data for those projects should be included separately in the data response to allow consideration of the impact of the inclusion or exclusion of such projects, as well as the appropriateness of excluding such projects from near term marginal costs but including for long term marginal costs.”

²¹ PCF Comments, p. 3.

²² PD, p. 42.

²³ SCE Comments (June 19, 2026), p. 4.

Overview of the Avoided Cost Calculator

1. Introduction

This document describes the inputs, assumptions and methods used in the 2026 Distributed Energy Resources (DER) Avoided Cost Calculator (ACC). The DER ACC model, documentation and supporting files are available at:

- <https://willdan.box.com/v/2026CPUC-ACC>, and
- <https://www.cpuc.ca.gov/dercosteffectiveness>

1.1 Purpose of the ACC and Recent Developments

The ACC is used to determine the benefits of Distributed Energy Resources (DER), such as energy efficiency and demand response, for cost-effectiveness analyses. The ACC is the first part of the three-part cost-effectiveness process used by the CPUC to determine the costs and benefits of customer programs.¹ The ACC calculates hourly system-level costs of providing electric or gas service for 30 years, in \$/kWh or \$/therm. These hourly avoided costs are used with specific program data, such as hourly energy savings, to determine program benefits. Those benefits are then compared to program costs to determine cost-effectiveness.

The ACC both includes an electric avoided cost calculator and a natural gas avoided cost calculator, sometimes referred to as the ACC electric model and gas model, respectively. The ACC determines several types of avoided costs including avoided generation capacity, energy, ancillary services, greenhouse (GHG) emissions, high global warming potential gases, transmission and distribution capacity, and natural gas infrastructure.

Since 2020, the ACC has been closely aligned with the grid planning efforts of the Integrated Resource Planning (R. 16-02-007) and distribution planning proceedings. The avoided costs are based on data and analysis from Integrated Resource Planning (IRP) modeling, except for the avoided costs of transmission and distribution, which are based on data and guidance from utility transmission planning and distribution planning proceedings as well as supplemental general rate case inputs. The ACC also provides hourly ancillary service price forecasts from the SERVVM reliability and production simulation model used in the IRP proceeding. Ancillary services are a potential benefit for dispatchable DER that can provide reserves in CAISO markets. This is different than the avoided ancillary service cost that estimates the value that DER provides to avoid procuring spinning reserves when load is reduced.

In 2020, the ACC was updated to fully support evaluation of electrification measures that increase load but may decrease total GHG emissions. This included adopting a new avoided cost of high

¹ This three-part process is described in the "Cost-Effectiveness Brief Overview," available at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm>

⁸⁴ 2026 Distributed Energy Resources Avoided Cost Calculator Documentation, at 5, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a.pdf>, accessed September 18, 2026.

Attachment 7: R.22-11-013, *Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge’s Ruling Issuing Updated 2023 Avoided Cost Calculator Staff Proposal for Party Input*, June 19, 2026, at 4, excerpt.

SCE agrees with the proposed changes to simplify the calculation of the transmission marginal costs, but only for the 2026 ACC update. SCE has not been able to fully investigate the impacts of retiring the LNBA method on a permanent basis during the two-week comment period for the Revised Proposal. However, SCE expects that the number and value of projects to be evaluated under the LNBA will shrink for this cycle. In the interest of efficiency and simplifying the analysis, it makes sense to only use the DTIM method given the smaller scope of projects that would normally be evaluated under the LNBA in this cycle.

SCE expects the scope of projects that would otherwise be evaluated under the LNBA to shrink due to a discovery that was made in the process of replying to an ED data request pertaining to the calculation of transmission avoided costs for this ACC update cycle. For the 2024 update cycle, SCE included the Wildlife Substation as a locational, load-driven transmission project. However, no SCE retail customers are expected to be connected to or served from the Wildlife Substation under non-emergency operations, as SCE is building the substation to exclusively serve Riverside Public Utilities (RPU).² RPU receives transmission service from SCE and will serve the retail customers connected to the Wildlife Substation once it is in service. The ACC is designed to estimate avoided costs related to DERs located behind customer meters on SCE’s system. SCE cannot offer programs or compensation for DERs located on RPU’s system and therefore has absolutely no opportunity to avoid costs associated with the Wildlife Substation through DER programs and tariffs. The Wildlife Substation should have been excluded from the 2024 ACC transmission marginal costs had SCE provided the appropriate context at the time. As a result, for 2026, the one remaining LNBA project would shift to the DTIM.

² [See Riverside Transmission Reliability Project](https://www.sce.com/about-sce/reliability/projects-in-progress/riverside-transmission-reliability-project), available at: <https://www.sce.com/about-sce/reliability/projects-in-progress/riverside-transmission-reliability-project>.

Attachment 8: 2026 ACC Documentation, at 70, excerpt.⁸⁵

2026 Distributed Energy Resources Avoided Cost Calculator Documentation

Table 10-1. SCE Project Costs and Load Forecast

Year	SCE Project Cost (\$M)				SCE Forecast from CEC		
	Pardee Sylmar	New Serrano	Alberhill	Total	Forecast for SCE (MW)	Annual Peak Demand Growth (MW)	Median Growth (2025-2040)
					24647		
2025	2.108	26.546	4.73	33.384	25973	1,326	224
2026	1.5	35.324	9.65	46.474	26106	133	224
2027	1.5	12.253	73.369	87.122	26319	213	224
2028	1.5	10.533	53.492	65.525	26538	219	224
2029	0.579	17.754	13.326	31.659	26841	303	224
2030					27081	240	224
2031					27314	233	224
2032					27523	209	224
2033					27721	198	224
2034					28075	354	224
2035					28524	449	224
2036					28687	163	224
2037					28917	230	224
2038					29129	212	224
2039					29332	203	224
2040					29646	314	224
NPV (2025 - 2029)				\$228.28			972.5

Notes: SCE Data request response: ED-SCE-ACC Transmission-2026 - 4/1/2026
Source for 2024-2040 Demand: CEC Demand Forecast 2024-2040 Baseline Forecast, Form 1.5 SCE Planning Area: Historical and Extreme Temperature Non-Coincident Peak Demand (MW), 2024 Data reflects Historical Net Peak, 2025-2040 data located at <https://efiling.energy.ca.gov/GetDocument.aspx?tm=260928>

Real Discount Rate Used: 4.94%

Table 10-2. Derivation of SCE Transmission Marginal Cost Factor

Marginal Transmission Cost Factor			
2026 MC Factor for Transmission			
Loaders & Financial Factors Inputs:			
Transmission Real Economic Carrying Charge (RECC)	[1]	6.98%	No update from 2024 value
Electric Transmission O&M (\$/kW-yr)	[2]		Applied later
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	0.87%	No update from 2024 value
General Plant Loading Factor Transmission (Annual Capital basis)	[4]	2.27%	No update from 2024 value
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]		
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	2.36%	No update from 2024 value
MARGINAL INVESTMENT			
Marginal Investment	[8]	\$100.00	
Annualized Marginal Investment	[9]	\$6.980	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense (to be added directly, rather than included as a factor)	[10]		
A&G Expense	[11]	\$0.87	[11] = [8] x [3]
General Plant	[12]	\$0.16	[12] = [9] x [4]
Sub-total Marginal Expenses	[13]	\$1.028	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]		
Sub-total Carrying Costs	[16]		[16] = [14] + [15]
Franchise Fees and Uncollectibles	[17]	\$0.19	[17] = ([9] + [13] + [16]) x [7]
Marginal Cost	[18]	\$8.20	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	8.20%	[19] = [18] / [8]

2026 Distributed Energy Resources Avoided Cost Calculator Documentation

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⁸⁵ 2026 Distributed Energy Resources Avoided Cost Calculator Documentation, Table 10-1: SCE Project Costs and Load Forecast, at 70, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a.pdf>, accessed September 18, 2026.

Attachment 9: 2025-2026 Board Approved CAISO TPP, at 171, excerpt.⁸⁶

BOARD APPROVED 2025-2026 ISO TRANSMISSION PLAN

MAY 19, 2026

Project ID	Project Name	PTO	Current ISD
2223-P-03	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Jan-30
2223-P-04	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	Apr-27
2223-P-05	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	Dec-30
2223-R-07	Garberville Area Reinforcement	PG&E	Dec-28
2223-P-08	IV-North of Songs 500 kV line and North of Songs Substation	SDG&E	Jan-32
2223-R-09	Los Banos 230 kV Circuit Breaker Replacement	PG&E	Dec-28
2223-R-10	Los Banos 70 kV Area Reinforcement Project	PG&E	Jan-31
2223-P-09	Lugo-Victor-Kramer 230 kV Upgrade	SCE	Jun-29
2223-R-13	Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest	SDG&E	Dec-32
2223-R-15	North East Kern 115 kV Line Reconductoring	PG&E	Mar-32
2223-P-11	North Gila-Imperial Valley 500 kV line	SDG&E	Dec-31
2223-P-12	North of Songs-Sorreno 500 kV Line	SDG&E / SCE	Jan-32
2223-R-16	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Apr-28
2223-R-18	Redwood City Area 115 kV System Reinforcement	PG&E	Feb-30
2223-P-15	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	Dec-31
2223-R-19	Santa Rosa 115 kV lines reconductoring project	PG&E	May-32
2223-R-20	Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	May-33
2223-P-17	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	Aug-31
2223-R-23	Tesla 115 kV Bus Reconfiguration Project	PG&E	Jun-28
2223-P-20	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	Sep-31
2122-R-13	Table Mountain Second 500/230 kV Transformer	PG&E	May-29
2122-R-11	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	Apr-28
2122-R-10	San Jose Area HVDC 500 kV Line (Metcalf - San Jose)	PG&E	May-28
2122-R-01	Antelope 66 kV Short Circuit Duty Mitigation Project	SCE	Dec-26
2122-P-04	Manning 500/230 kV Substation Project	PG&E	Apr-28
2122-P-03	Collinsville 500/230 kV Substation Project	PG&E	May-28
2122-P-01	GLW/VEA Area Upgrades	GLW/VEA	Jun-28
1819-R-09	South of Mesa Upgrade	PG&E	Jun-29
1819-R-08	Round Mountain 500 kV Dynamic Voltage Support (Fern Road Substation)	PG&E	May-26
1415-R-03	Martin 230 kV Bus Extension	PG&E	Oct-28
1314-R-27	Wheeler Ridge Junction Substation	PG&E	May-34
1314-R-13	Midway-Kern PP #2 230 kV Line	PG&E	Dec-28
1314-P-01	Lugo-Mohave series capacitor upgrade	SCE	Jun-26
1213-R-14	Lockeford-Lodi Area 230 kV Development	PG&E	Jun-31
1213-P-02	Lugo - Eldorado series cap and terminal equipment upgrade	SCE	Jun-26
1112-R-10	Kern PP 115 kV Area Reinforcement	PG&E	Aug-29
09-R-03	Alberhill 500 kV Method of Service	SCE	Dec-29

⁸⁶ 2025-2026 Board Approved CAISO TPP, May 19, 2026, project 2223-R-18, at 171, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026.

Attachment 10: PG&E’s response to DR Cal Advocates-PG&E-032, question 1, sent June 30, 2026.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

Data Request No.:	CalAdvocates_032-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_032-Q001
Request Date:	May 21, 2026
Requester DR No.:	032
Requesting Party:	Public Advocates Office
Requester:	James Lau
Date Sent:	June 30, 2026
PG&E Witness(es):	Marco Rios

SUBJECT: DEFERABLE TRANSMISSION PROJECTS

QUESTION 001

PG&E proposes that “Coburn-Oil Fields 60 kV System Project (Revised; Original Project: Oil Fields 60 kV Area Voltage Support)” is a deferable project for developing marginal transmission capacity costs (MTCC).¹ The in-service date for this project was updated to September 2030, on page 184 of the May 30, 2025, Board approved 2024-2025 California Independent Service Operator (CAISO) Transmission Plan.² However, this project is absent in the May 12, 2026, Revised Draft 2025-2026 CAISO Transmission Plan.³

- a. Please provide PG&E’s estimated in-service date for project “Coburn-Oil Fields 60 kV System Project (Revised; Original Project: Oil Fields 60 kV Area Voltage Support).”
- b. Was this project rescoped or canceled following the issuance of the Board approved 2024-2025 CAISO Transmission Plan?
 - i. If yes, please provide the new cost estimate for this project, the new in-service date, and if possible, a citation or source where PG&E obtained this information.

¹ See PG&E’s July 29, 2025, response to SEIA data request 1, question 9, attachment “GRC-2023-PhII_DR_SEIA_001- Q009-Atch02.xlsx,” tab “Deferable Projects,” line 14.

² CAISO, 2024-2025 Transmission Plan, Board Approved, May 30, 2025, Table 8.1-1: *Status of Previously Approved Projects Costing Less than \$50 M*, line 28 at 184, available at <https://www.caiso.com/documents/iso-board-approved-2024-2025-transmission-plan.pdf>, accessed May 20, 2026.

³ CAISO, 2025-2026 Transmission Plan, Revised Draft, May 12, 2026, Table 8-2: *Status of Previously Approved Projects with Cost < \$50 Million*, at 167-169, available at <https://stakeholdercenter.caiso.com/InitiativeDocuments/Revised-Draft-2025-2026-Transmission-Plan.pdf>, accessed May 20, 2026.

- ii. If yes, does PG&E still consider this project as meeting its proposed deferrable criteria⁴ and should be included in its proposed MTCC estimate?
- c. In the July 29, 2025, response to data request SEIA-PG&E-001, question 9, PG&E stated the project's estimated cost was between \$20-\$50 million.⁵ Is \$20-\$50 million still the current cost estimate range for this project?
 - i. If not, please provide the current cost estimate range for this project, and if possible, a citation or source where PG&E obtained this information.

ANSWER 001

- a. The current in-service date for the Coburn-Oil Fields 60 kV System Project is September 2031.⁶
- b. No, the Coburn-Oil Fields 60 kV System Project has not been rescoped or canceled by the CAISO. The CAISO included the project as part of the 2025-2026 Transmission Planning Process (TPP)⁷. Further, the CAISO Board Approved 2025-2026 Transmission Plan does not identify the project as re-scoped or canceled.⁸
- c. Yes, the cost for the Coburn-Oil Fields 60 kV System Project is still within the \$20-\$50 million range.

⁴ *Pacific Gas and Electric Company 2023 General Rate Case Phase II Errata Testimony to April 18, 2025 Prepared Testimony Exhibit PG&E-2 Cost of Service Studies (PG&E-2), Chapter 4: Deferrable Transmission Capacity Projects (Chapter 4), October 29, 2025, at 4-8 to 4-11.*

⁵ See PG&E's July 29, 2025, response to SEIA data request 1, question 9, attachment "GRC-2023-PhII_DR_SEIA_001- Q009-Atch02.xlsx," tab "Deferrable Projects," row 14.

⁶ See CAISO's January 28, 2026 Transmission Development Forum approved projects update, "[Approved Projects - Transmission Planning Process - Jan 28, 2026.xls](#)", PG&E tab, row 11, column S, January [Meetings | Transmission development forum | California ISO](#).

⁷ The September 24, 2025 CAISO stakeholder presentation identifies the project as modeled in the base case used for the Central Coast/Los Padres reliability assessment: [Presentation- 2025-2026 Transmission Planning Process - Sep 24, 2025](#), first project listed (page 85)

⁸ CAISO's Board Approved Transmission Plan sections 2.3.3 Previously Approved Project Re-scopes (page 83-88) and 2.3.5 Previously Approved Projects Cancellations (page 90-91) do not list this project: [Board Approved - 2025-2026 Transmission Plan](#)

Attachment 11: PG&E’s response to DR Cal Advocates-PG&E-032, question 4, sent June 30, 2026.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalAdvocates_032-Q004
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_032-Q004
Request Date:	May 21, 2026
Requester DR No.:	032
Requesting Party:	Public Advocates Office
Requester:	James Lau
Date Sent:	June 30, 2026
PG&E Witness(es):	Marco Rios

SUBJECT: DEFERABLE TRANSMISSION PROJECTS

QUESTION 004

PG&E included project “Morgan Hill Area Reinforcement (FKA: Spring Substation)” in its proposed deferrable projects list for developing its proposed MTCC.¹⁴ However, the May 12, 2026, Board approved 2025-2026 CAISO Transmission Plan adopted a rescope of project “Morgan Hill Area Reinforcement (FKA: Spring Substation).”¹⁵

- a. Does the rescoped “Morgan Hill Area Reinforcement (FKA: Spring Substation)” project still meet PG&E’s proposed deferrable project criteria for developing an MTCC?¹⁶ If yes, please explain why and if no, please explain why not.

ANSWER 004

- a. No, the Morgan Hill Area Reinforcement still does not meet the criteria to be deemed as a deferrable project. The projected load on the associated facilities to be upgraded exceeds the 25% deficiency for a single contingency event within the 5-yr horizon. As explained in Chapter 4 – Deferrable Transmission Capacity testimony,¹⁷ thermal overload issues exceeding 25 percent (relay loadability threshold) can trigger the automatic action of protection devices in the system, which can cause cascading outages and potentially lead to blackouts. This threshold

¹⁴ See PG&E’s July 29, 2025, response to SEIA data request 1, question 9, attachment “GRC-2023- PhII_DR_SEIA_001-Q009-Atch02.xlsx,” tab “Deferrable Projects,” line 17.

¹⁵ CAISO, *2025-2026 Transmission Plan*, Revised Draft, May 12, 2026, Table ES-1: *Reliability Driven Projects Recommended for Approval*, line 30 at 9

¹⁶ PG&E-2, Chapter 4 at 4-8 to 4-11.

¹⁷ PG&E-2, Chapter 4 at 4-8, line 16 to line 27.

provides a safety margin to protect equipment and maintain system stability. As such, the project continues to not be deferrable.

Attachment 12: 2022 ACC Documentation, at 92, excerpt.⁸⁷

CPUC 2022 ACC Documentation

Table 35. Derivation of SDG&E Systemwide Transmission Project Costs and Load Forecasts

Discount rate	7.17%	2021 After Tax WACC Provided by SDG&E		
Inflation	2.62%			
Real Discount Rate	4.43%			

Year	SDG&E XMSN Capital Expenditures (\$M)	SDG&E Forecast from IEPR		
		SDG&E Forecast (MW)	Annual Peak Demand Growth (MW)	Median Growth (2021-2029)
		4,578		
2021	52.68	4,547	(31)	29
2022	81.16	4,583	36	29
2023	0.00	4,600	17	29
2024	73.06	4,651	51	29
2025	0.00	4,682	31	29
2026	0.00	4,711	29	29
2027		4,753	42	29
2028		4,768	15	29
2029		4,795	27	29
NPV(2021-2026)	\$186.29			149.92

Section 3 Standard Escalation Factors: Escalation Factors Transmission Plant	
Year	%
2021	2.90%
2022	6.45%
2023	3.64%
2024	1.54%
2025	0.59%
2026	0.63%
2027	1.12%
2028	1.55%
2029	1.89%
Average (2021-2026)	2.62%

- IEPR Values Drawn from CEU 2020 Managed Forecast - LSE and BA Mid Demand - Low AAEE Case. Form 1.5d (1-in-10): SDG&E TAC Area.
[IEPR SDGE Used_CEDU 2020 Managed Forecast - LSE and BA Tables Mid Demand - Low AAEE Case.xlsx | Powered by Box](#)

In the prior update, the SDG&E systemwide transmission load growth and investment calculation omitted one of the forecast years due to a negative load growth value. The use of this value would have resulted in undefined project costs under the DTIM method. In the 2022 update, this problem is instead addressed by taking the median growth over a 9-year forecast and applying it to each year within the time horizon. This aligns with the method used in both the 2021 and 2022 ACC updates for SCE and helps to address a concern that the shift in growth forecasts each year can lead to volatility in the final transmission value.

In SDG&E's data request response, forecasted capital expenditures for potentially DER-deferrable transmission projects were provided for the years 2021-2026. Because all relevant values were available for this time horizon, including corresponding load growth and escalation rates, all six years are incorporated in the calculation. Noting the anomaly when compared with the prior forecast, SDG&E explained that the high transmission capital costs represent an unusual concentration in expenditures due to pent up need. Further changes in the forecast when compared to the prior ACC inputs are due in part to the change in vintage of the forecast (the 2020 and 2021 ACC relied on a 2019 forecast whereas the 2022 ACC relies on a 2022 forecast) and several projects being included which were not yet solidified within the 5-year horizon as of 2019.

⁸⁷ 2022 Distributed Energy Resources Avoided Cost Calculator Documentation, at 92, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf>.

Attachment 13: 2026 ACC Documentation, at 72, excerpt.⁸⁸

2026 Distributed Energy Resources Avoided Cost Calculator Documentation

Table 10-4. SDG&E Project Costs and Load Forecast

Year	SDG&E XMSN Capital Expenditures (\$M)	SDG&E Forecast from IEPR		
		SDG&E Forecast (MW)	Annual Peak Demand Growth (MW)	Median Growth (2025-2044)
		4,647		
2025	28.1	4,558	N/A	110
2026	52.0	4,509	11	110
2027	62.8	4,617	48	110
2028	77.6	4,727	110	110
2029	25.3	4,831	104	110
2030	24.5	4,938	107	110
2031		5,045	108	110
2032		5,147	101	110
2033		5,247	100	110
2034		5,341	95	110
2035		5,467	126	110
2036		5,538	71	110
2037		5,749	211	110
2038		5,945	196	110
2039		6,135	190	110
2040		6,329	194	110
2041		6,474	145	110
2042		6,621	146	110
2043		6,756	136	110
2044		6,886	130	110
NPV(2025-2044)	\$216.41			522.90

Notes:

SDG&E Response to 2.18.2026 Transmission Data Request

Transmission Capital Expenditures for 2026-2030 from SDG&E's TPR process data

Expenditures listed reflect planned projects that are expected to be completed but may be viewed as proxies for transmission that could potentially be deferred due to load reductions from incremental DER

IEPR source for 2025-2044 data: CED 2025-2050 Forecast - Local Reliability Scenario - LSE and BAA Tables, Form 1.5d (1-in-10); SDG&E TAC Area

IEPR source for 2024 data: Value for 2024 from CED 2024-2040 Forecast - Local Reliability Scenario - LSE and BAA Tables, Form 1.5d (1-in-10); SDG&E TAC Area. Accessible at <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0>

Real Discount Rate Used:

7.01%

2026 Distributed Energy Resources Avoided Cost Calculator Documentation

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⁸⁸ 2026 Distributed Energy Resources Avoided Cost Calculator Documentation, Table 10-4: SDG&E Project Costs and Load Forecast, at 72 available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/2026-acc-models/2026-acc-documentation-v1a_20260921.pdf.

Attachment 14: 2020 ACC Workshop: Transmission and Distribution Avoided Capacity Costs Presentation Slides, at 6.⁸⁹

		+ DTIM method		7.14% Dec 2020 after-tax WACC	
+ SDG&E load forecast could not be used (was negative growth)		• Replaced with IEPR without DER forecast		2.35% Inflation	
+ Analysis used 2021-2024				4.68% Real Discount Rate	
Year	SDG&E Capital Expenditures (\$M)	IEPR without DER Peak Load (MW)	IEPR without DER based forecast Annual Peak Demand Growth (MW)		
2020	46.28	4,571	(31)		
2021	9.78	4,579	38		
2022	5.82	4,636	58		
2023	4.96	4,695	58		
2024	3.44	4,749	54		
2025	0	4,800	50		
2026	0	4,845	45		
2027	0	4,892	47		
2028	0	4,938	46		
NPV(2021-2024)	\$21.85		185.63		

⁸⁹ 2020 ACC Workshop: Transmission and Distribution Avoided Capacity Costs Presentation Slides, at 6, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/T&D%20Workshop.pdf, accessed September, 23, 2026.

Attachment 15: 2021 ACC Documentation, at 6, excerpt.⁹⁰

CPUC 2021 ACC Documentation

Table 18. Total SCE Transmission Marginal Cost (\$/kW-yr \$2020)

	Marginal Cost (\$/kW-yr)
System-wide projects	\$5.07 / kW-yr
Alberhill project averaged over SCE system	\$16.75 / kW-yr
Transmission O&M	\$ 6.70 / kW-yr
Total	\$28.52 / kW-yr

Transmission O&M is from ED-SCE-001, and reflects SCE's 2018 GRC.

9.1.3 SDG&E

SDG&E's response to the Energy Division data request indicated a preference for a regression-based estimation of marginal costs. Unfortunately, the provide system peak load data reflected a negative load growth trend. With that negative growth trend, the regression method resulted in a nonsensical negative marginal capacity cost for transmission.

To address the negative load growth problem, we again turn to the IEPR forecast. Combining the SDG&E Mid Low IEPR load forecast with SDG&E's forecasted capacity-driven projects allow us to derive transmission marginal costs via the DTIM approach. Using the IEPR forecast, we see increased peak load for all years except 2020.

Table 19. SDG&E Transmission capital forecast and IEPR forecast without DER (\$M and MW)

Discount rate	7.14% Dec 2020 after-tax WACC
Inflation	2.35%
Real Discount Rate	4.68%

Year	SDG&E Capital Expenditures (\$M)	IEPR without DER based forecast	
		IEPR without DER Peak Load (MW)	Annual Peak Demand Growth (MW)
2020	46.28	4,571	(31)
2021	9.78	4,540	38
2022	5.82	4,579	58
2023	4.96	4,636	58
2024	3.44	4,695	54
2025	0	4,749	50
2026	0	4,800	45
2027	0	4,845	47
2028	0	4,892	46
NPV (2021-2024)	\$21.85		185.63

Excludes projects deemed too large to be deferred (Sunrise Powerlink and South Orange County Reliability Enhancement)

In applying the DTIM method, we use the period 2021 through 2024. Excluding 2020 avoids the problem introduced by the large negative load growth in that year of the IEPR forecast. In addition, \$40.5M of the \$46M 2020 investment cost is due to the last phase of a project that was commenced in 2012. Including

⁹⁰ 2021 ACC Documentation v1b, Table 19: SDG&E Transmission capital forecast and IEPR forecast without DER (\$M and MW), at 52, available at: https://files.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2021%20ACC%20Documentation%20v1b.pdf, accessed September 23, 2026.

Attachment 16: 2022 ACC Documentation, at 85, excerpt.⁹¹

CPUC 2022 ACC Documentation

200 tons of hourly marginal GHG emissions are added, reducing the average grid intensity to 0.14 tons/MWh. This is below the annual target of 0.16 tons/MWh. To meet the 0.16 tons/MWh target emission intensity level, 480 tons of increased emission would be allowed based on electrification load of 3000 MWh.

In step 1, the 200 tons of hourly marginal emissions are valued at the cap-and-trade price of \$80/ton and the GHG Adder cost of \$30/ton for a total cost of \$22,000. In step 2, the portfolio is rebalanced to allow for an increase of 480 tons which are valued at the GHG Adder cost of \$30/ton for a cost reduction of \$14,400. In total the cooling load increases GHG costs by only \$7,600. Dividing the \$7,600 in GHG costs by the 200 tons of marginal GHG impacts results in a savings of \$38/Ton. The reduced GHG costs divided by the 3,000 MWh of added load results in a GHG cost of \$2.5/MWh.

Table 27. GHG Cost: Commercial Space Heating Electrification Example

	A	B	C	
	GHG Cost (\$/ton)	Emissions (tons CO ₂)	Cost (\$)	
1 Tons added		200		
2 Tons allowed by intensity target		480		0.16t/MWh * L8
Marginal emissions impacts				
3 Cap and Trade	\$80.00	200	\$16,000	
4 GHG Adder	\$30.00	200	\$6,000	
5 Total marginal emission cost			\$22,000	L3 + L4
Rebalancing Impacts				
6 GHG Adder	\$30.00	(480)	-\$14,400	
7 Net GHG cost			\$7,600	L5 + L6
8 Usage added (MWh)		3000		
9 Net GHG cost per MWh			\$2.53	L7/L8
10 Net GHG Cost per ton of added marginal emissions			\$38.00	L7/L1

14.3 Utility-Specific Transmission Costs

14.3.1 PG&E

Recent ACCs have used transmission marginal capacity costs from PG&E's GRC proceedings. PG&E has estimated those values for ratemaking purposes using the Discounted Total Investment Method (DTIM). The DTIM calculates the unit cost of transmission capacity as the present value of peak demand driven transmission investments divided by the present value of the peak demand growth. This unit cost is then annualized using a Real Economic Carrying Charge (RECC) with adjustments for other ratepayer -borne costs, such as administrative and general costs (A&G) and operations and maintenance costs (O&M). This most recent calculation as performed by PG&E is provided in the table below, with a derived marginal transmission capacity cost of \$12.02/kW-yr (in \$2021).

However, in the California Public Utilities Commission Decision 21-11-016 published November 18, 2021, the Commission shifted to adopt the Solar Energy Industries Association's proposed marginal transmission capacity cost of \$52.45 per kilowatt year (in \$2021).

⁹¹ 2022 Distributed Energy Resources Avoided Cost Calculator Documentation, at 85, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf>.

Attachment 17: AECA’s response to DR Cal Advocates-AECA-002, sent April 8, 2026.

Agricultural Energy Consumers Association

**RESPONSE TO PUBLIC ADVOCATES OFFICE
DATA REQUEST NO. CAL ADVOCATES-AECA-002**

CPUC Proceeding No. A.24-09-014

April 8, 2026

1. Page 4, lines 10 through 15 of AECA’s opening testimony states “Analysis of transmission costs and generation additions shows that at least 76% of marginal transmission costs are explained by new renewable generation over the period from 2012 to 2023. These costs should be assigned in the same manner as renewable energy costs to customer classes on a per kilowatt-hour basis because these investments have been made to deliver energy for environmental compliance, not capacity for reliability.” However, page 3 lines 6 through 7 of AECA’s opening testimony states “AECA does not propose a formal quantified revenue allocation for the different rate classes.”

- a. Please provide clarity on whether AECA is making a formal transmission revenue requirement allocation proposal, a marginal transmission capacity cost proposal, or is instead making an observation.

- i. Is AECA formally proposing that the transmission revenue requirement should be allocated on an equal cents per kilowatt hour (kWh) basis?

- A. **No, AECA is not making a formal proposal on how these marginal transmission costs should be used to allocate revenue. AECA’s position is that PG&E’s proposed marginal cost-based revenue allocations historically have been erratic and, accordingly, the agricultural class increase should be capped at no more than 0.3% above system average per year.**

However, given the close relationship between incremental transmission investment and incremental renewable generation additions over the 2012-2023 period, the transmission costs could reasonably be allocated in the same manner as the portion of marginal generation energy costs attributable to renewable generation.

1. If AECA is formally proposing an alternative transmission revenue requirement allocation proposal, does AECA assert that transmission revenue allocation is within the California Public Utilities Commission’s (CPUC) jurisdiction and not the Federal Energy Regulatory Commission’s (FERC) jurisdiction?

- A. **As noted above, AECA is not making a proposal for an alternative allocation of transmission revenue requirements. AECA is proposing that the**

agricultural class increase be capped at 0.3% above the system average per year.

2. If AECA is not making a transmission revenue requirement allocation proposal, please clarify what AECA is proposing relating to the sentence from page 4, lines 12-15 of AECA's opening testimony, "These costs should be assigned in the same manner as renewable energy costs to customer classes on a per kilowatt-hour basis because these investments have been made to deliver energy for environmental compliance, not capacity for reliability."

- A. **AECA is not making a formal proposal on how these marginal transmission costs should be used to allocate revenue. AECA's position is that PG&E's proposed marginal cost-based revenue allocations historically have been erratic and, accordingly, the agricultural class increase should be capped at no more than 0.3% above system average per year.**

However, given the close relationship between incremental transmission investment and incremental renewable generation additions over the 2012-2023 period, the transmission costs could reasonably be allocated in the same manner as the portion of marginal generation energy costs attributable to renewable generation.

- b. Given AECA's assertion that 76% of transmission costs are not related to adding capacity, does AECA agree that only 24% of PG&E's transmission revenue requirement should be considered marginal?

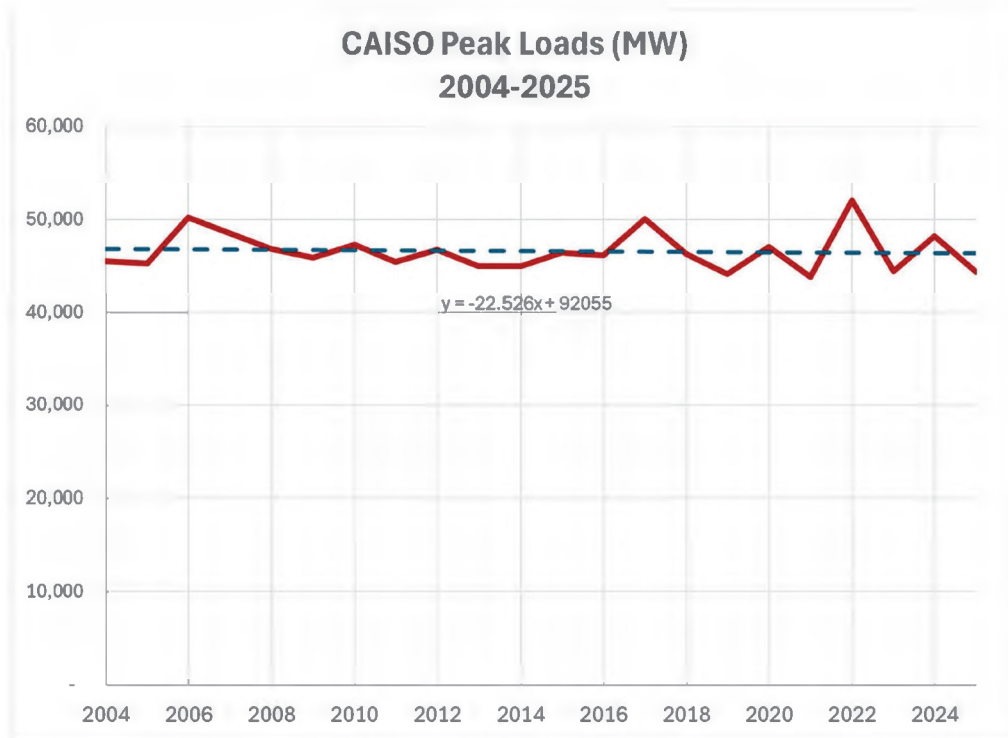
- A. No.

- i. If not, please explain.

- A. **That transmission is added simply because of an increase in demand is a myth. Transmission is added to bring additional generation to serve load. Added transmission has no value without sufficient generation at the source end. In some cases, that transmission is added to meet increased peak demand when peak demand is rising. However, the CAISO peak load has not increased measurably since 2006.¹ But it also is added to bring energy to the grid, just as the transmission link from the Diablo Canyon Power Plant to the Helms Pumped Storage plant was intended to send energy, not reliability related capacity.**

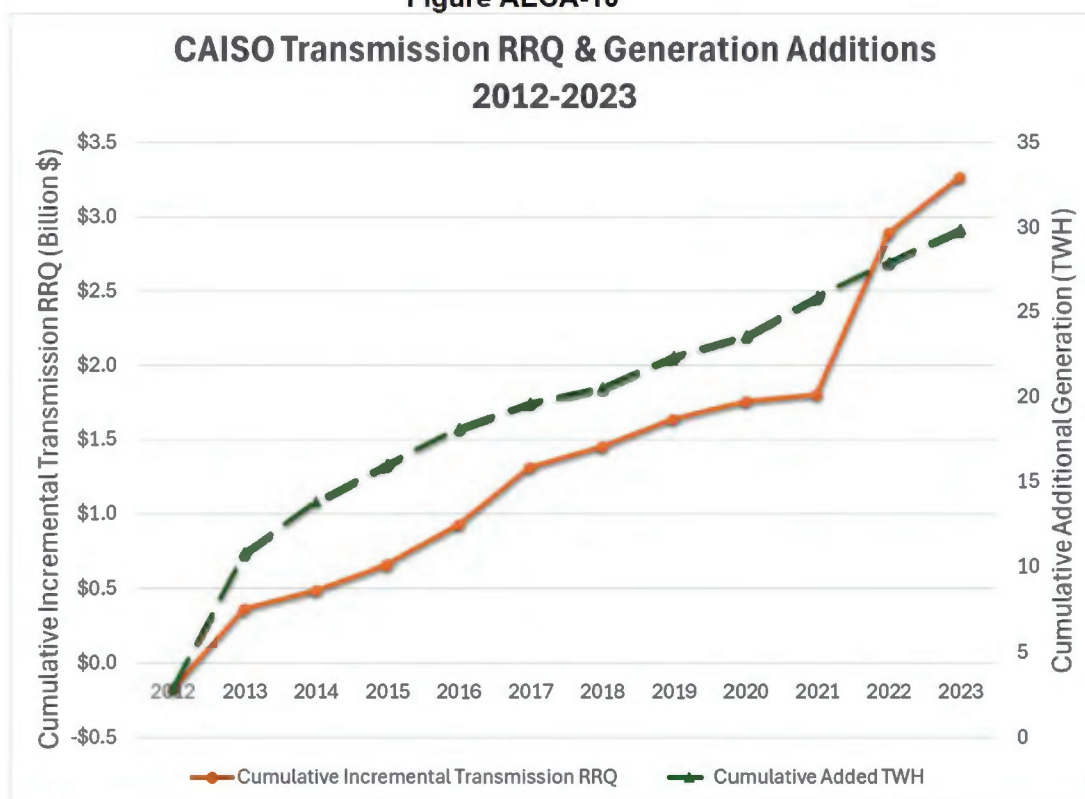
The chart below shows that the CAISO peak load has been flat and even falling at a rate of 22.5 MW per year since 2004. There has been no incremental demand increase that justifies transmission investment as a response to higher peak demands. Thus, it appears that the reason for increased transmission investment is the additions of renewable energy since 2012.

¹ The 2022 peak was an accounting anomaly that has since been corrected.



See the following excerpt from AECA’s testimony explaining further that the marginal transmission is added to bring new generation from renewables to the market.

Figure AECA-10

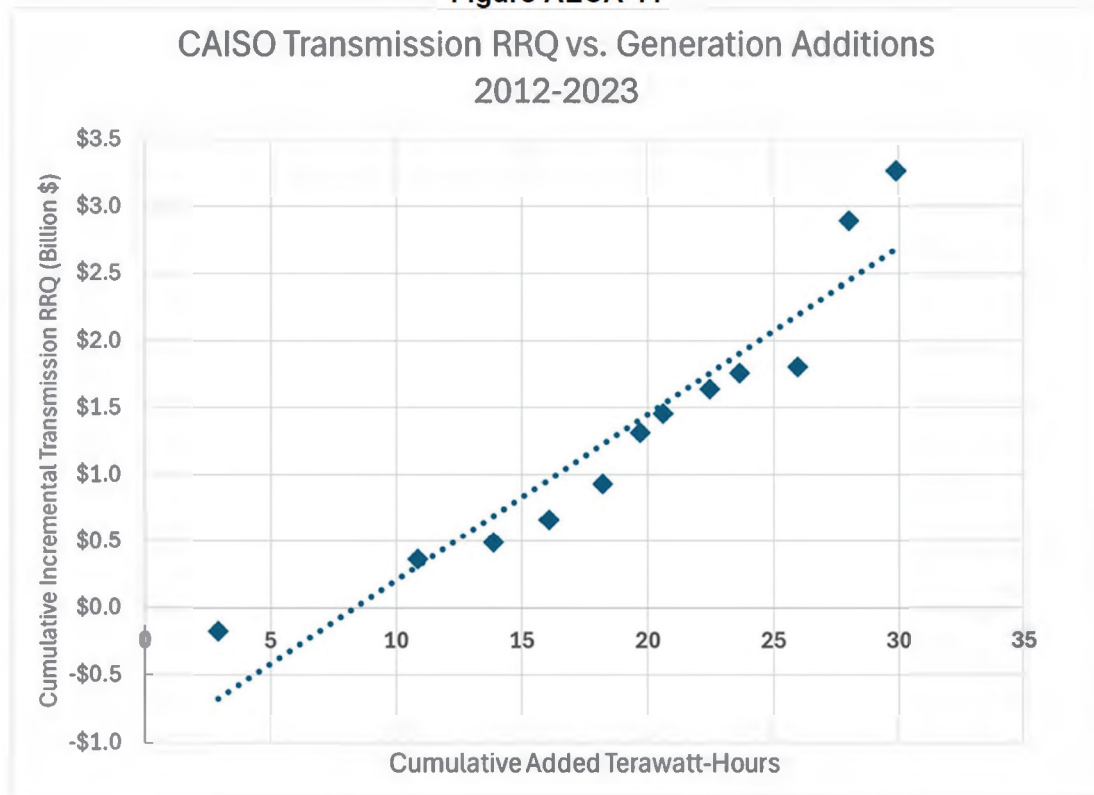


Looking at this chart, it becomes obvious that incremental transmission spending is driven largely by additions of generation. This fact is particularly evident when transmission costs rise so rapidly despite no significant load growth. In addition, the CAISO transmission has been built to convey renewable energy that is replacing natural generation, not capacity for peak reliability purposes. And because 76% of the new generation is for renewable energy, not for peak reliability, kilowatt-hours of energy is the best metric. For this reason, the marginal or incremental cost should be expressed in dollars per kilowatt or kilowatt-hour.

Using these two data sources, we calculated the incremental or marginal cost for transmission using the change in annual revenue requirements as a proxy for the direct cost. Figure AECA-11 shows how transmission revenue requirement increases relate to generation additions. Based on this analysis, the marginal cost of transmission is \$125 per megawatt-hour or \$0.1246 per kilowatt-hour.² Given that retail transmission rates for the three IOUs have increased 250% to \$0.04016 cents per kilowatt-hour, this result is consistent with the economic principle that marginal costs are above average costs when average costs are rising.

² The R-squared is 0.881, and the standard error is \$0.0138 per kilowatt-hour.

Figure AECA-11



2. PG&E asserts its proposed marginal transmission capacity cost (MTCC) of \$63.61 per kilowatt-year (kW-year) reflects that only 14.4% of all of its transmission projects should be categorized as both capacity related and deferrable.
 - a. Please explain AECA's perspective on PG&E's estimate that only 14.4% of PG&E's transmission projects should be considered marginal?

A. AECA disagrees with PG&E's analysis of what drives transmission investment. As shown in AECA's testimony, it is renewable generation that explains at least 90% of marginal transmission investment. This linkage is obvious when reviewing the CAISO's transmission planning reports when the CAISO explains the reason for adding transmission is to deliver new renewable generation. For example:

The Memorandum of Understanding (MOU) is an agreement between The California Public Utilities Commission (CPUC), The California Energy Commission (CEC), and the ISO. The MOU tightens the linkages between resource and transmission planning activities, interconnection processes and resource procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by

*Senate Bill 100.*³

- b. Is AECA proposing that PG&E should increase its MTCC proposal such that it reflects 24% of PG&E's transmission projects instead of 14.4%?
 - A. **AECA is proposing that the MTCC should reflect 100% of PG&E's transmission projects based on the analysis that shows (1) that transmission investment is driven largely by the addition of new generation which has been substantially renewables since 2012, and (2) that CAISO peak load remains unchanged since 2004, indicating no new generation is being added solely to meet capacity needs. PG&E has failed to explain why its transmission revenue requirements have increased 150% since 2012 despite no increase in peak demand over the same period. Without that explanation it is not possible to understand how PG&E arrived at asserting that only 14% of its transmission costs are deferrable. AECA has provided a transparent and easily understandable explanation for this increase that aligns with most if not all of these costs being deferrable.**
- 3. Page 23, line 1 of AECA's testimony provides AECA's own marginal cost of transmission at \$125 per kWh based on the premise that 76% of transmission costs are not capacity related.
 - a. Does AECA assert that its proposed marginal cost of transmission estimate reflects the same marginal cost function that is represented by PG&E's marginal transmission **capacity** cost of \$63.61? Or does AECA's marginal transmission cost reflect a different transmission function? For example, PG&E's proposed MTCC is the marginal cost of transmission capacity and not the marginal cost of volumetric transmission usage.
 - A. **To clarify, AECA asserts that 100% of incremental transmission costs since at least 2012 are not capacity related. AECA demonstrates that the MTCC is entirely energy related because the CAISO peak load has not changed since 2012.**
 - i. Please explain.
 - A. **AECA's proposed marginal cost function reflects the reality of what has driven transmission investment, and is the most likely driver of future transmission investment as the state pushes for its SB 100 goal of 100% carbon-free generation by 2045. The MTCC should be allocated over energy delivered because transmission has been built to convey the energy from renewable sources.**
 - b. If the CPUC adopts AECA's proposed \$125 per kWh marginal cost of transmission, please explain what function AECA proposes it should serve?

³ See CAISO, "Transmission Planning," <https://www.caiso.com/generation-transmission/transmission/transmission-planning>, retrieved April 7, 2026.

- A. **This calculation should serve as a replacement for PG&E's proposed MTCC for all purposes. That said, AECA's position is that PG&E's proposed marginal cost-based revenue allocations historically have been erratic and, accordingly, the agricultural class increase should be capped at no more than 0.3% above system average per year.**
 - i. Should it be used for revenue allocation?
 - A. **See response to Question 3.b above.**
 - ii. Should it be used for rate design?
 - A. **See response to Question 3.b. above.**
 - iii. Should it be used for economic development rates?
 - A. **See response to Question 3.b. above.**
 - iv. If AECA proposes its use should be limited to informative purposes only, what proceedings or aspects should it inform?
 - A. **AECA believes this analysis is a critical updated input for the Avoided Cost Calculator.**
4. Solar Energy Industry Association's (SEIA) opening testimony at page 59, lines 4 through 7 advocates time-of-use based transmission rates.
- a. Does AECA support SEIA's proposal for time-of-use based transmission rates, the current flat volumetric rate design, or an alternative rate structure?
 - A. **AECA has no position on SEIA's rate design proposal at this time.**
 - b. Does AECA have a position on how its \$125 per kWh marginal cost of transmission should be used to design time-of-use based transmission rates?
 - A. **AECA believes this marginal cost calculation should be used in a manner consistent with how renewable energy costs are introduced into the rate design since the two factors are directly interlinked in the marginal cost calculation.**
5. Page 20, lines 1 through 13 of AECA's testimony argues that Marginal Distribution Capacity Costs (MDCC) allocated to the agricultural class should be reduced by 64% because the Sustainable Groundwater Management Act (SGMA) will force a reduction in groundwater pumping, thereby freeing distribution capacity and lowering PG&E's costs to serve them.
- a. Please provide all workpapers, calculations, source data, and supporting documentation used to drive the recommendation that distribution marginal costs should be reduced by exactly 64%. Please provide Excel files with all formulas

Attachment 18: 2025-2026 CAISO Board Approved TPP, at 2, excerpt.⁹²

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considers a wide array of technical options in the transmission planning process, ranging from conventional transmission additions, reinforcements or upgrades to existing facilities to fully utilize existing infrastructure, and grid-enhancing technologies that can, where feasible, increase capacity more economically than building new transmission lines. While each transmission plan builds on previously approved plans and projects, the ISO also reviews previously approved projects, on a case-by-case basis, when there is a material change in circumstances that warrant reconsideration.

The transmission projects recommended for approval in this plan represent significant investments that are phased in over lead times of up to eight to 10 years, which are reasonable for some of the projects to be completed. These costs translate to approximately 0.5 cents per kWh over the life of the projects, phased in as the new facilities come online. The costs for consumers are ultimately determined as part of the rate design process between utilities and their regulatory authorities. These projects are consistent with the ISO's 20-Year Transmission Outlook and co-optimized with resource planning through the CPUC's integrated resource planning process. The ISO also conducted detailed evaluations of alternatives to ensure achievement of the most efficient and cost-effective long-term solutions. The infrastructure investments also have tremendous reliability and economic benefits for California, and the transmission upgrades are required to cost-effectively bring reliable decarbonized power to California consumers and industry across all seasons of the year.

Transmission projects are categorized as reliability-driven needed to serve load reliably and meeting NERC national standards; policy-driven needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.

Integrated Zonal Planning and Interconnection

Proactive and coordinated resource and transmission planning are the cornerstone of the ISO's transmission planning process and have taken on even greater importance over the past several years. The strategic direction of this approach was initially set forth in a joint Memorandum of Understanding (MOU) signed in December 2022 by the ISO and the state's two principal energy policy entities, the CEC and the CPUC. Consistent with that agreement, this Transmission Plan represents the latest iteration of our integrated approach whereby the CEC completes annual energy demand forecasting, which is used as the basis of the CPUC's Integrated Resource Planning process. The ISO then supplements the CPUC's Integrated Resource Plans with the plans of other Local Regulatory Authorities (e.g. municipal utilities) as the central inputs into the annual transmission planning process (TPP). The zones identified for new transmission are

⁹² 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 2, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026.

Attachment 19: 2025-2026 CAISO Board Approved TPP, at 21, excerpt.⁹³

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account an array of considerations, with advancing the state's objectives of a cleaner future grid playing a major part in those considerations.

Reliability-driven needs

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, as well as the ISO's own transmission planning standards. The reliability studies, necessary to ensure such compliance, comprise a foundational element of the transmission planning process. During the 2025-2026 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.¹⁶ The ISO performed this analysis across a 15-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, which range in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation.

Policy-driven needs

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support local, state, and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California's renewable energy goals. In the past, the focus of these goals was on the renewables portfolio standard (RPS) set out in various legislation. First, on the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2, and then, on the 60% renewables portfolio standard by 2030 objective in

¹⁶ This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan and subsequent transmission plans, the ISO has not included in this year's Plan the additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The ISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the ISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

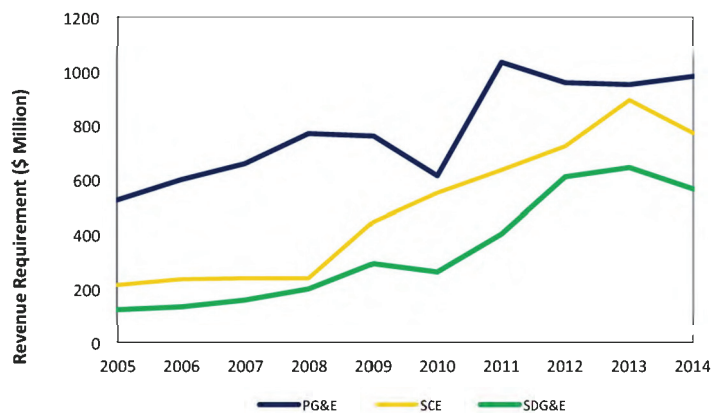
⁹³ 2025-2026 CAISO Board Approved TPP, May 19, 2026, at 21, available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf>, accessed September 23, 2026.

Attachment 20: 2014 CPUC Assembly Bill 67 Report to the Legislature, at 17, excerpt.²⁴

charges for ratepayers. CPUC representation in FERC rate cases from 2004-2014 has resulted in a cumulative savings of over \$1.264 billion for ratepayers.

Transmission revenue requirements for the electric IOUs have been trending up since 2003. Much of the increase in the revenue requirements is due to additional transmission plant capital additions which have been built by the utilities. From 2004 – 2014, PG&E's transmission revenue requirement has increased at a 12.15% annual average rate; SCE's at a 22.5% annual average rate; and SDG&E's at a 36.6% annual average rate. These increases are driven primarily by CAISO reliability and RPS mandates.

Figure 2.9: Trends in Transmission Revenue Requirements¹⁵



¹⁵ Does not include costs related to Reliability Services or Transmission Access Charge.

²⁴ 2014 CPUC Assembly Bill 67 Report to the Legislature, *Electric and Gas Utility Cost Report: Public Utilities Code Section 747 Report to the Governor and Legislature*, April 2015, at 17, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/reports_and_white_papers/2014ab67final.pdf, accessed September 23, 2026.

Attachment 21: 2021 CPUC Senate Bill 695 Report to the Legislature, at 41, excerpt.²⁵

Projects that expand the capacity of the transmission grid are included in CAISO's annual Transmission Planning Process (TPP), pursuant to requirements of FERC Order No. 890 ("Order 890"), which requires transparent transmission planning. However, a majority of the California IOUs' spending on capital additions is not related to grid capacity expansion and therefore receives no review by the CAISO through the TPP. FERC has determined that Order 890 does not apply to projects that do not expand the capacity of the transmission grid. These projects that are outside of the scope of the TPP are referred to as "self-approved." A TO rate case at FERC includes no review of specific utility self-approved projects. The end result is that there is no state or federal review on either the need or costs for these projects.

In data reported by the IOUs to the CPUC in July 2020, capital additions between 2016 and 2019 for all three IOUs totaled over \$7.5 billion. Approximately \$4.5 billion (60 percent) of these capital additions were utility self-approved, while \$3 billion were CAISO-approved. The annual average for all capital additions for 2016 to 2019 was \$1.875 billion. In comparison, in 2010, the capital additions for the IOUs totaled less than \$950 million, with the share of self-approved projects in 2010 at 50.6 percent and CAISO-approved projects was 49.4 percent. The annual capital additions projected for just 2020 and 2021 total \$5.3 billion, with approximately 60 percent being self-approved projects across all three IOUs, with PG&E exceeding 80 percent self-approved.

As the previous table shows, the largest CAISO-approved projects occurred in SDG&E's and SCE's territories. Table 12 shows the proportion of CAISO-approved and utility self-approved projects between 2010 and 2019. While over 80 percent of SCE's and SDG&E's project costs during that time were CAISO-approved, primarily because of the large projects in Table 11 only 31 percent of PG&E's capital additions were CAISO approved. PG&E's overall capital project costs far exceed those of either SCE or SDG&E and a large majority of those costs were self-approved.

Table 12: CAISO-approved and Utility Self-approved Projects 2010-2019 (\$000)

Utility	Self-approved Projects	CAISO-approved Projects	Total Capital Additions	Percentage Self-approved	Percentage CAISO-approved
SDG&E	\$ 0.81 million	\$ 3.99 million	\$ 4.80 million	16.9%	83.1%
SCE	\$ 1.18 million	\$ 5.08 million	\$ 6.26 million	18.9%	81.1%
PG&E	\$ 6.16 million	\$ 2.77 million	\$ 8.93 million	69.0%	31.0%
Total	\$ 8.15 million	\$11.84 million	\$19.99 million	40.8%	59.2%

Declining Loads and Increasing Rates

For more than a decade, the total annual gross load, which is a measure of all energy delivered for the supply of end-use customer loads, has been declining in the CAISO control area. However, over that same period, CAISO's High Voltage Transmission Access Charge (TAC), which is a primary component of transmission charges on customers' bills, has increased substantially. In 2009, the annual load in the CAISO

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²⁵ 2021 CPUC Senate Bill 695 Report to the Legislature, *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1*, May 2021, Table 12: *CAISO-approved and Utility Self-approved Projects 2010-2019 (\$000)*, at 41, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf, accessed September 23, 2026.