BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Authority to Increase its Authorized Revenues for Electric Service in 2025, among other things, and to Reflect that Increase in Rates.	A.23-05-010 (Filed May 12, 2023)

OPENING COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON PROPOSED DECISION ON TEST YEAR 2025 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

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Pursuant to Rule 14.3(b) of the California Public Utilities Commission Rules of Practice and Procedure Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (collectively, the "Companies") provide the following Subject Index of Recommended Changes in support of its opening comments to the July 28, 2025 Proposed Decision on Test Year 2025 General Rate Case ("GRC") for Southern California Edison Company ("SCE") ("Proposed Decision" or "PD"):

1. The PD Should Be Corrected to Authorize Wildfire Hardening Strategies Tailored to Risk Analysis and Subject Matter Expertise.

2. The Proposed Decision should be revised to correct technical errors in its approval of SDG&E's proposed share of San Onofre Nuclear Generating Station ("SONGS") marine mitigation costs, allowing for the provision of revenue requirement updates under previously established processes.

3. The Proposed Decision should be revised to authorize a post-test year ratemaking ("PTYR") mechanism that accounts for necessary capital additions during attrition years.

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I. INTRODUCTION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (the "Rules" of the "Commission" or "CPUC"), San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas") respectfully submit these Opening Comments on the July 28, 2025, Proposed Decision on Test Year 2025 General Rate Case ("GRC") for Southern California Edison Company ("SCE") ("Proposed Decision" or "PD"). In these Opening Comments, SDG&E and SoCalGas request that the Proposed Decision be revised to correct specified factual, legal and technical errors. Consistent with Rule 14.3, these Comments focus on errors in the Proposed Decision, propose modifications to Findings of Fact ("FOF"), Conclusions of Law ("COL") and Ordering Paragraphs ("OP"), and are timely filed within 20 days of service of the Proposed Decision.[1]

First, the Proposed Decision should be revised to authorize SCE's wildfire mitigation forecasts and Targeted Undergrounding Program miles. The PD correctly concludes that utility-

[1] Failure to address any issue in these Comments does not indicate agreement or waiver. These Opening Comments also comply with Rule 14.3's page limitation for general rate case comments on a proposed decision (which does not include the subject index, table of authorities, and appendix).

caused ignitions have and can lead to catastrophic wildfires resulting in significant property damage, economic losses, and fatalities,[2] but then erroneously authorizes a wildfire hardening approach that fails to adequately address risk and factually errs in concluding that covered conductor offers comparable levels of risk reduction to undergrounding.[3] SCE's proposed approach, which takes into account risk factors such as high winds, egress constraints, and significant fire consequence on a location-specific basis, should be adopted to support authorization of additional undergrounding miles.

Second, the Proposed Decision should be revised to correct technical errors in its approval of SDG&E's proposed share of San Onofre Nuclear Generating Station ("SONGS") marine mitigation costs.[4] The Proposed Decision correctly approved SDG&E's uncontested request for cost recovery of its 20% share of SONGS-related marine mitigation costs and worker's compensation costs, and the calculation mechanism for those costs. However, the Proposed Decision inadvertently provides language and implementation requirements that do not permit SDG&E to efficiently provide timely updates reflecting the SONGS revenue requirement for years 2026, 2027, and 2028.

Third, the Proposed Decision should be revised to authorize a PTYR mechanism that accounts for necessary capital additions during the attrition years. For all but wildfire mitigation capital additions, the Proposed Decision authorizes a PTYR mechanism that escalates revenue requirement by the most recent Consumer Price Index ("CPI"), with a 5% annual cap. Although the proposed PTYR mechanism is intended "to give SCE an opportunity to offset some

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2 PD, FOF 302 at 891.

3 PD, FOF 283-284 at 889.

4 Minor typographical errors have also been identified and corrected in the accompanying Appendix A.

inflationary price increases and to recover costs for capital investments,"[5] it accounts only for inflation and fails to provide adequate funding for new capital spending and assets placed in service in the attrition years, thus funding only replacement of existing assets for non-wildfire capital additions.

II. ARGUMENT

A. The PD Should Be Corrected to Authorize Wildfire Hardening Strategies Tailored to Risk Analysis and Subject Matter Expertise

The PD factually errs in dramatically scaling back SCE's Targeted Undergrounding Program ("TUG") and accepting The Utility Reform Network's ("TURN") recommendation to authorize only 31 percent of SCE's TUG mileage forecasts. The most obvious error in accepting TURN's analysis appears to be the PD's willful blindness to the continued wildfire risk in southern California; while the PD acknowledges that SCE has reduced the risk of utility-related wildfire through the installation of covered conductor in SCE's HFRAs,[6] not once in the PD's thousand pages does it acknowledge the two catastrophic wildfires that occurred in January—facts that the Commission can, and should, officially notice. Regardless of the cause, these wildfires demonstrate the potential consequence of any ignition during high-risk conditions. SCE's forecasted undergrounding proposals will more effectively reduce the risk of ignition where one might have catastrophic consequences similar to the January events, and should be approved.

The PD engages in faulty logic in equating the risk reduction of targeted undergrounding in the highest risk areas to that of covered conductor, even when covered conductor is paired

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[5] PD, FOF 842 at 947.

[6] *Id.* at 373.

with additional technologies.[7] Covered conductor and undergrounding are not commensurate risk reduction tools, particularly in areas meeting SCE's criteria to define SRAs—particularly areas with high winds.[8] While the other criteria SCE uses to define its SRAs are important to understanding wildfire risk, as evidenced by the events in January, any ignition in high winds can be catastrophic.

The PD even acknowledges that "undergrounding may be appropriate in high wind locations where covered conductor circuits would still be subject to high PSPS likelihood." But paradoxically it goes on to limit SCE's ability to address the full extent of those circuits, potentially exposing customers to both increased wildfire and PSPS risk. The PD's limitations on the scope of undergrounding leaves customers exposed to unnecessary risk and runs contrary to the requirements of California Public Utilities Code ("Cal. Pub. Util. Code") Section 8386.[9]

Undergrounding reduces nearly all ignition risk (98%) and has the benefit of corresponding reductions in PSPS impacts. SCE estimates that covered conductor is only 73% effective at reducing wildfire risk.[10] By adopting TURN's recommendations, the PD appears to

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7 *See, e.g.* PD at 376.

8 *Id.* at 375-376.

9 *See,* Cal. Pub. Util. Code Section ("§") 8386(c)(14) (requiring utilities to include "[a[description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulating of distribution wires, and replacing poles" in Wildfire Mitigation Plans; Cal. Pub. Util. Code § 8386(c)(8) (utilities must identify "circuits that have frequently been deenergized pursuant to a deenergization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future deenergization of those circuits, including, but not limited to, the estimated annual decline in circuit deenergization and deenergization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines.").

10 PD at 387.

expand the use of a less effective wildfire mitigation strategy to achieve the same risk reduction as SCE's forecasts. But that blanket approach leaves customers in the highest risk areas continually exposed to ignition risk and requires what might otherwise be unnecessary hardening in lower risk areas.

The PD recognizes that covered conductor is an effective risk mitigation tool, but it is also important to acknowledge that it has limitations. While there have been no ignitions from "risk drivers that covered conductor directly mitigates,"[11] that leaves out many potential sources of ignitions, including degradation, equipment failure, pole failures (such as car accidents), and non-wire contacts to equipment. SCE has experienced ignitions on covered lines, demonstrating the need for the Commission to support undergrounding in areas where merited. The PD should be revised to approve SCE's undergrounding forecasts, consistent with the risk framework that was vetted and approved as part of SCE's WMPs.[12]

Finally, the PD should recognize the need for ongoing flexibility in the scope of both covered conductor and undergrounding as SCE further develops and refines its risk models. The PD discusses that SCE's models may be improved by incorporation of "the SRA criteria as part of the risk analysis required by the RDF so that it may yield the utility's best estimate of risk"[13] but fails to authorize funding in a manner that allows flexibility if and when SCE implements those enhancements. SCE may fill "gaps" in risk data over the four-year GRC cycle that may

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11 *Id.* at 388.

12 *Id.* at 375. SDG&E recognizes that the Commission has found that "Commission ratification of an approved WMP does not consider or authorize rate recovery," but argues that the Commission's interpretation of Cal. Pub. Util. Code § 8386.4(b) leaves electrical corporations at risk of unfunded mandates and inability to comply with regulatory requirements set by the agency designated to assess and reduce utility-related wildfire risk in California, constituting legal error.

13 *Id.*

better inform its hardening strategies. The PD should be revised to allow for additional undergrounding consistent with risk model enhancements and future WMP approvals.

B. The PD Should be Revised to Reflect Established Implementation for SONGS Revenue Requirement Updates

The PD "authorize[s] and adopt[s] SDG&E's request for a 2025 SONGS revenue requirement of $1.691 million (2025) for its 20 percent share of these SONGS-related costs."[14] The PD further recognizes that an approved environmental services stipulation addressing forecasted costs among SCE, Cal Advocates and TURN may result in changes to the amount of SDG&E's SONGS-related revenue requirement and therefore "authorize[s] use of the Revenue Requirement Calculation Methodology provided by SDG&E to adjust its costs calculations."[15]

In its Ordering Paragraph 24, however, the PD directs SDG&E:

> Within 30 days upon issuance of this decision, San Diego Gas & Electric Company (SDG&E) shall file an annual Tier 1 advice letter, by July 1 of each year, requesting approval of SDG&E's San Onofre Nuclear Generation Station Balancing Account and Marine Mitigation Memorandum Account to reflect the updates of the San Onofre Nuclear Generation Station revenue requirement for years 2026, 2027, and 2028.[16]

Although SDG&E can comply with the directive to file an advice letter within 30 days of a final SCE TY 2025 GRC decision for year 2025-related SONGS revenue requirement, SDG&E's ability to file an update for years 2026, 2027, and 2028 is tied to the timing of SCE's filing of its advice letter for 2026 and successive post-test years. SCE's advice letter will

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14 PD at 677 (citation omitted). *See also* PD, OP 22 at 1003.

15 *Id*. *See also* PD, OP 23 at 1003-1004. SDG&E notes that the environmental services stipulation may result in changes to the SONGS-related revenue requirement in the test year (2025) and all succeeding post-test years. For this reason, in Appendix A, SDG&E has proposed modification of OP 22 to permit adjustment of its SONGS-related revenue requirement in 2025 using the authorized Revenue Requirement Calculation Methodology.

16 *Id.*, OP 24 at 1004.

"specify the revenue requirement adjustment for Operations and Maintenance expense and capital-related costs" and occur by December 1 of the year prior to the effective date of the rate adjustment.[17] SDG&E will require use of its Revenue Requirement Calculation Methodology and SCE's escalation rate to calculate SDG&E's post-test year updates.

Similar to SCE's annual revenue requirement adjustment process for post-test year periods,[18] SDG&E's current process for filing its annual consolidated update to update its revenue requirement for the following year will apply and will incorporate SONGS-related revenue requirement updates.[19] The PD's requirement for SDG&E to file its update of SONGS-related revenue requirement by July 1 of the year in which the new rate applies presents a technical error. The record is devoid of evidence to depart from the established year-end consolidated updated filings schedule and SDG&E requests that the PD be corrected to require SDG&E to include the SONGS-related updates for years 2026, 2027 and 2028 in its consolidated year-end rate filings through its efficient and previously established processes. Proposed language is contained in Appendix A.

C. The PD's Post Test Year Ratemaking (PTYR) Methodology Should Reflect Necessary Capital

The PD authorizes SCE a PTYR mechanism for its GRC cycle, tying the adjustment to "its base revenue requirement as a percent based on the most recent [Consumer Price Index

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17 *Id.*, OP 3 at 997.

18 *See id.* at 838 ("Consistent with current procedure, SCE proposes to submit its 2026, 2027, and 2028 attrition requests via advice letter by December 1 of the prior year. The advice letter would specify the revenue requirement adjustment for O&M escalation and changes in capital-related costs.") (citation omitted); *see also id.*, OP 415 at 996 (adopting SCE's request to submit annual attrition request via advice letter).

19 Pursuant to Resolution E-5217 (August 4, 2022), SDG&E files a Tier 2 advice letter "Preliminary Annual Electric Consolidated Update" by November 15th of each year, followed by a Tier 1 advice letter by December 31, to update rates for January 1 of the following year.

(CPI)] attrition increase/decrease each year for 2026, 2027, and 2028, plus additional increases for budget-based wildfire mitigation capital additions."[20] The PD further places an annual 5% cap on attrition increases.[21] Although the PD acknowledges that "[t]he Commission has held that utility-specific indices more accurately reflect how utilities incur costs as compared to consumer retail price changes reflected through CPI"[22] and elsewhere adopts use of such an index for utility cost escalation factors to project SCE's cost of service revenue requirements for its test year, the PD goes on to limit SCE's attrition year escalation for O&M and capital costs to CPI capped at 5% per year.[23] While SoCalGas and SDG&E disagree with the use of CPI, as the PD correctly finds that CPI does not accurately reflect the cost of utility assets, the more significant error here is not the index by which to escalate but rather with the PTYR mechanism itself.

To establish attrition year funding, the PD uses a simple approach that escalates the test year revenue requirement for all but SCE's wildfire mitigation program. This relatively straight-forward approach is appropriate for O&M expenses, but not for capital. The PD's PTYR treatment errs by failing to reflect necessary capital investment and additions by: (1) not

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[20] PD at 842.

[21] *Id.* The PD further notes: "For purposes of this decision, we assume a three percent increase to the base revenue requirement figure each attrition year corresponding to the reported average annual CPI-U increase from December 2023 to December 2024."

[22] *Id*. Longstanding Commission precedent has repeatedly recognized that CPI is an inappropriate measure for the costs that utility companies incur during the attrition year period. *See, e.g.*, Decision ("D.") 04-07-022 at 278; D.14-08-032 at 653 ("The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services."); D.15-11-021 at 390-391 (same); D.19-09-051 at 707-708 (same); D.21-08-036 at 547 ("As we have previously explained, the CPI reflects consumer retail price changes and does not reflect how utilities incur costs.").

[23] PD at 842.

adequately providing revenues for new capital expenditures in the attrition years and (2) only reflecting partial revenue needs associated with test year capital in the attrition years.

First, to provide context, PTYR is typically determined by a formula or mechanism, as the Commission explains in D.20-01-002:

> The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years.[24]

This explanation demonstrates that O&M attrition is straightforward – escalating test year expenses – however, capital is more complex with various ways to determine the appropriate capital revenue requirements in the attrition years. Additionally, D.20-01-002's finding demonstrates that O&M and capital typically have different approaches for determining attrition year revenue requirements. The Commission has historically reaffirmed this separate treatment for O&M and capital most recently in PG&E's 2023 GRC, SCE's prior (2021) GRC, and SoCalGas's and SDG&E's 2019 GRC, finding "it reasonable to treat expense and capital-related costs differently for purposes of post-test year ratemaking because expense and capital-related costs can affect revenue requirement differently."[25] Despite the Commission acknowledging the differences between O&M and capital, the PD applies the same method for attrition of O&M to capital (*i.e.*, escalating test year revenue requirement).

O&M and capital impact the revenue requirement differently and thus should not have the same treatment in PTYR. O&M expenses are typically recurring in nature and have a duration of one year or less. An example of an O&M expense is employee salaries that are paid

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[24] D.20-01-002 at 8.

[25] D.23-11-069 at 707-708. *See also* D.19-09-051 at 706-707, D.21-08-036 at 546-547.

each year. Another example of an O&M expense is inspections on electrical equipment that are completed on a recurring cycle. Because the duration of the expense is one year or less, the O&M revenue requirement is also annual for the GRC cycle, in other words, the O&M expense is equal to the O&M-related revenue requirement. Accordingly, escalation of test year O&M revenue requirement to determine the attrition years produces an appropriate result and provides adequate funding for expected O&M expenses.

Capital, by contrast, represents project costs and investments in assets that are used and useful for multiple years and recovery of the capital expenditures incurred are spread over time (over the useful life). Each capital investment addresses a different component on the system. Even routine capital projects that replace a given number of widgets per year, for example, are not the same widget being replaced each time (like O&M) but could be a new widget in a different location. Because capital projects have a start and end date and have useful lives greater than one year, the costs can vary from year to year corresponding to the project lifecycle. The capital costs that are spent during the construction phase of the project are referred to as capital expenditures. Those capital expenditures, once the asset is placed into service and it is used and useful, become what is referred to as capital additions or plant in service. Capital additions are the total costs of assets placed into service, recorded as plant on a utility's balance sheet, and depreciated over the asset's useful life. Capital additions are the more appropriate predictor of capital-related revenue requirements and attrition needs.

Revenue requirement is what is recovered in rates. Related to capital, the revenue requirement includes the annual capital-related costs, which are depreciation (annual portion of capital in-service), return and taxes. The capital-related costs are recovered in rates over time through the recurring annual capital-related revenue requirement of a given capital project. The capital-related revenue requirement does not then provide incremental revenues for new capital occurring in that period. Rather, it provides for recovery of a portion of the capital costs associated with a completed capital project from the prior period. For example, if you have a capital project that is \$50 million in capital additions with a 50-year useful life, all else being equal, the utility will collect \$1 million in capital-related costs each year for 50 years through depreciation (\$50 million divided by 50 years) plus taxes and return. Each year, that \$1 million of revenue requirement is designated for the same completed capital project. Applying the PD's PTYR mechanism to this example project, the \$1 million collected beginning in the test year for capital-related costs would be escalated by CPI. If CPI is estimated to be 3%, in the first attrition year, the utility would collect \$1.03 million. The \$1 million is to recover the portion of the up-front capital investment associated with that year of the in-service project, which leaves only \$300,000 to invest in new capital or address rising costs (*i.e.*, inflation). Therefore, the \$300,000 does not reflect the additional capital that will continue to be needed each year to invest in the system. Expanding on this simple example, now assume this is a recurring capital program, such as a corrective maintenance program, where \$50 million of capital additions are needed each year in the attrition years. The \$1.03 million (incremental \$300,000) of authorized revenue requirement would not sustain the additional \$50 million in capital investment. For this, in the second year of the GRC cycle, a utility would need \$1.03 million in revenue requirement for the first \$50 million capital investment and an additional \$1 million in revenue requirement for the recurring work originally authorized in the test-year. Absent this type of authorization, additional capital needs in the post-test year period are not properly reflected in the authorized revenue requirement and limit a utility's ability to make new investments in the system. Accordingly, a PTYR mechanism that escalates revenue requirement, rather than addressing capital additions separately, will not allow SCE to sufficiently invest in new capital projects for safety and reliability in the attrition years.

In addition to the PD's PTYR failure to adequately address new capital needs, it also misses the mark in making SCE whole for partial year capital in-service dates. Because the Commission determines the test year revenue requirement "based on its extensive review of the test year forecasts,"[26] all investor-owned utilities, including SCE in this proceeding, forecast capital projects along with the dates the projects are estimated to be used and useful. If a given capital project's estimated in-service date is anything later than January 1 of the test year, it means that the revenue requirement for that capital project will be prorated based on the in-service date. For example, assume the Commission approves a capital project with an annual revenue requirement of $100 that is estimated to go into service in June of the test year. The test year revenue requirement will be half of the total amount because of the June in-service date or $50. Because capital revenue requirement is collected over the life of the asset, beginning in year 2 of the GRC cycle, the utility will need the entire revenue requirement to service that asset or $100, not the test year's funding level of $50. A PTYR mechanism that only escalates revenue requirement means that in this example, the $50 for this capital project would be escalated by CPI to determine attrition year funding. The result of which is that in each attrition year, the utility will not be made whole for the missing $50 to service this capital project. Thus, the utility is not adequately funded for its overall capital needs during this GRC cycle leaving unfunded capital for authorized work that is completed and placed in service during the test year,

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[26] D.20-01-002 at 8.

and it does not provide funding for any additional capital needs in the post-test years.[27] This simple example illustrates that a PTYR mechanism for capital that is only applied to the authorized revenue requirement is inadequate and does not account for the complexities of how in-service capital is recovered.

The result of both failures of the PD's PTYR mechanism (insufficient funding associated with new capital and in-service dates) created by escalating capital-related revenue requirement, rather than by escalating capital additions, is that a utility is not provided with ample attrition revenue requirements to continue the work authorized in the test year. This includes safety and reliability funding needed for compliance programs and to reduce risks. While the PD "find[s] it reasonable to authorize a PTYR mechanism during this GRC cycle to give SCE an opportunity to offset some inflationary price increases and to recover costs for capital investments, particularly investments for wildfire risk mitigation,"[28] the PD's PTYR does not allow SCE to recover costs for the capital investments that the Commission expects to be performed in the attrition years.

Further, the result of adopting a PTYR mechanism that does not adequately cover capital needs will also directly impact the imputed authorized capital levels in the Risk Spending Accountability Reporting ("RSAR"). The RSAR gives the Commission oversight into utility spending and reports on capital expenditures, not revenue requirement. As explained in the examples above, simply adding the CPI value to the capital expenditures for the post-test years is

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[27] By escalating SCE's test year revenue requirement rather than its capital additions during the post-test years, the PD's PTYR would inhibit SCE's ability to earn its authorized rate of return. Thus, this PD would effectively be setting a new and reduced authorized rate of return, which is outside the scope of this proceeding.

[28] PD at 842.

not a true representation of the funding the utility has been authorized under the PTYR mechanism. The reality is that a PTYR mechanism based on escalating revenue requirement is not authorizing *any* additional capital expenditures in the post-test years because the revenue requirement only reflects projects that were completed by the test year. Because of this, while utilities are required to compare their actual spending to the authorized spending in the RSAR, conclusions from the RSAR data would be inaccurate and not provide the Commission with useful insight. The absence of clearly defined capital expenditures undermines the effectiveness of RSAR results. Without defining O&M and capital separately in the attrition years, accountability reporting assessments may yield inconsistent or misleading results, which would potentially compromise decision-making and transparency.

The appropriate way to fix this error is to adopt a PTYR mechanism for capital based on capital additions. TURN acknowledges this best practice recommending "a two-part PTYR mechanism that separately escalates O&M expenses and capital-related costs."[29] A PTYR mechanism based on test year capital additions will better reflect in the attrition years the capital-related revenue requirement associated with the authorized test year work and the revenue needed to perform incremental capital work the Commission expects of the utility. As mentioned, adopting a two-part PTYR mechanism is a longstanding Commission practice that should be approved here to meet the PD's stated balance of providing "SCE shareholders with a reasonable opportunity to earn their authorized rates of return"[30] with incentivizing "SCE to

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29 PD at 840.

30 *Id.*

manage its operations as efficiently as possible so that ratepayers are not further burdened with high inflationary indices that could outpace the CPI."[31]

III. CONCLUSION

SDG&E and SoCalGas respectfully request that the Commission's final decision include the revisions described above and in Appendix A.

Respectfully submitted this 18th day of August 2025.

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[31] *Id.* at 844.

APPENDIX A

PROPOSED CORRECTIONS AND CLARIFICATIONS TO FINDINGS OF FACT,

CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

APPENDIX A
PROPOSED CORRECTIONS AND CLARIFICATIONS TO FINDINGS OF FACT AND CONCLUSIONS OF LAW

ISSUE II.B (SONGS) (Section 32) **Proposed Corrections to Ordering Paragraphs**	
Location	**Proposed Language**
OP 22	San Diego Gas & Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2025 San Onofre Nuclear Generating Station (SONGS) revenue requirement of $1.691 million (2025), as adjusted by its Revenue Requirement Calculation Methodology for its 20 percent share of the SONGS~~s~~-related request for Marine Mitigation and Worker's Compensation.
OP 24	Within 30 days upon issuance of this decision, San Diego Gas & Electric Company (SDG&E) shall file a~~n annual~~ Tier 1 advice letter~~, by July 1 of each year, requesting approval of~~ updating SDG&E's San Onofre Nuclear Generation Station Balancing Account and Marine Mitigation Memorandum Account to reflect the updates of the San Onofre Nuclear Generation Station revenue requirement for 2025. For the years 2026, 2027, and 2028, SDG&E shall update its San Onofre Nuclear Generation Station Balancing Account and Marine Mitigation Memorandum Account revenue requirement in its Annual Consolidated Update Filing.