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**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.

Application 23-05-010
(Filed May 12, 2023)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

PUBLIC VERSION

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OPENING BRIEF OF THE UTILITY REFORM NETWORK

1. INTRODUCTION/SUMMARY OF RECOMMENDATIONS

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, The Utility Reform Network ("TURN") respectfully submits this opening brief in the Test Year 2025 General Rate Case ("GRC") of Southern California Edison Company ("SCE"). In the Sections that follow, TURN provides numerous recommendations regarding the proposals of SCE which are necessary to ensure that the rates adopted by the Commission in this proceeding are just and reasonable.[1] Moreover, TURN's recommendations will promote bill affordability for the millions of California households who depend on SCE to furnish essential electric utility services.

SUMMARY OF RECOMMENDATIONS

Section 2 – Legal Standard

Section 3 – Policy

- **3.1** The Commission should take steps to ensure transparency in light of the growing reliance on Machine Learning-based modeling methods.
- **3.2** The Commission must reject SCE's proposal to treat recorded 2023 capital expenditures as *per se* reasonable and prudent, even where opposed by other parties.

Section 4 – Affordability and Equity

4.1 Affordability

- The Commission should find that current levels of energy rates and bills are not affordable for many low-income customers despite low-income assistance programs.
- The Commission should find that authorizing SCE's requested increases will decrease affordability relative to its current levels.

[1] TURN reserves the right to address issues in its reply brief that TURN does not address here.

- The Commission should maintain SCE's disconnection cap of 4% going forward.

- The Commission should require SCE to include the "normalized" revenue requirement for its proposals going forward that removes the temporary reductions from capital investments.

- The Commission should weed out spending requests that provide minimal benefit and only approve those costs that SCE has demonstrated are both necessary for safe and reliable service and affordable for California customers.

4.2 Equity Issues

- Unaffordable utility bills can lead to utility disconnections, eviction and homelessness. During an electric rate affordability crisis and homelessness crisis, the Commission must consider the impact of rate increases on access to housing and carefully evaluate whether the increases are just and reasonable.

- The Commission should reject SCE's Transportation Electrification Grid Readiness (TEGR) plan load growth capital expenditures forecast that is based on a flawed modeling approach and would unnecessarily increase electric bills without producing benefits for most customers, especially low-income and vulnerable residential customers.

Section 5 – Risk-Informed Strategy and Business Plan

5.1 Climate Change Policy

5.2 Environmental and Social Justice Goals

5.3 Quantitative Risk Modeling

Section 6 – Distribution Grid

6.1 Infrastructure Replacement

6.1.1 Overhead Conductor Program

- The Commission should deny funding for the entire program other than the Accelerated OCP (AOCP) element. SCE's proposal to spend upwards of $330 million annually (from 2025-2028) would be unduly burdensome on ratepayers, and unlikely to achieve the projected reliability and safety benefits.
  - If the Commission chooses to authorize funding for more than the Accelerated OCP element, the funding should be tied to small-gauge conductor replacements (634 miles of the 1,680 miles SCE has proposed).
  - The Commission should deny ratepayer funding for replacements using bare conductor.

- The Commission should direct SCE to assess the benefits and costs of alternatives such as replacements of splice, connector or tap equipment as a lower-cost alternative to conductor replacement.
- Going forward, SCE must take steps to ensure that its reliance on machine learning (ML) models are less opaque, such as sharing the assumptions, testing multiple models, showing confidence intervals and ranges in results, and demonstrating the final model's performance against other potential models.

6.1.2 Underground Cable Replacement

- The Commission should authorize funding based on 800 miles of replacement, rather than SCE's proposed 1,600 miles, as the reduced number of miles will still enable achievement of 60-70% of the safety and reliability benefits according to SCE's models. The resulting funding for the 2023-2025 period on a forecast basis is $65.15 million, as compared to SCE's forecast of $114.1 million for that period.

6.2 Inspection and Maintenance, and Capital-related Expense

- The Commission should direct SCE to reevaluate and, as appropriate, scale back its deployment of and reliance on Inspect App for routine and compliance-based inspections.

- The Commission should direct SCE in its next GRC showing to analyze and address any trends in preventive or corrective maintenance and the impacts on associated capital replacement activities, broken out by each category of Distribution Infrastructure Replacement activity. This review should consider, at minimum, any trends in maintenance completion as indicated by "closed notifications."

6.3 Safety and Reliability Investment Incentive Mechanism

Section 7 – Meter Activities

7.1 Meter O&M
7.2 Meter Capital

Section 8 – Transmission Grid

8.1 Transmission Grid O&M
8.2 Transmission Grid Capital Expenditures
8.3 Transmission Infrastructure Replacement

Section 9 – Substation

9.1 Substation O&M

9.2 Substation Capital

9.3 Substation Infrastructure Replacement

- Circuit Breaker Replacement Program:

- The Commission should authorize $153.13 million rather than SCE's forecast of $164.29 million for the 2023-'25 period, a reduction of approximately 6.8%.
- The Commission should direct SCE to target replacement of only those circuit breakers that are deemed to be in "poor" or "very poor" condition according to SCE's arbitrary, non-linear Health Index.
- The Commission should direct SCE in its next GRC to: Present a more detailed analysis of unit costs, and break out its circuit breaker proposals into more granular voltage classes, rather than relying on two broad classes; substantiate the accuracy of its chosen health index, or to modify that index to comport with TURN's suggestion of a linear, unbiased index; and develop a designated age threshold approach for replacements. The Commission should also encourage SCE to engage in a stakeholder-involved process in order to develop such thresholds for equipment included in SCE-02, Vol. 02 ("Substations").

9.3.1 Substation Transformer Bank Replacement

- The Commission should authorize funding of $152.93 million rather than the $182.00 million for the 2023-'25 period, a reduction of approximately 6.9%.
- The Commission should direct SCE to target replacement of only those substation transformers that are deemed to be in "poor" or "very poor" condition according to SCE's non-linear Health Index.
- The Commission should direct SCE in its next GRC to: develop a designated age threshold replacement approach for replacements; engage in a stakeholder-involved process in order to develop such thresholds for substation transformer banks and other categories of equipment; and present unit cost and annual forecast information at a more granular level for assets like circuit breakers and transformers, such as by specific voltage classes rather than "A-bank" and "B-bank" transformers.

Section 10 – Grid Modernization, Grid Technology, and Energy Storage

10.1 Grid Modernization

- The Commission should adopt TURN's proposal, which is not only more affordable than SCE's proposal (savings of $168 million to $170 million) but also more cost-effective (BCR of 8.5 to 9.5 compared with 4.6 to 6.8 for SCE's proposal).

10.2 Grid Technology Assessments, Pilots, and Adoption

10.3 Energy Storage

- The Commission should reject SCE's proposal for LDES capital expenditures of $18.730 million for 2027 and $37.977 million for 2028. In addition, any approval for LDES investments be accompanied by annual progress reports that summarize the status of the project, funds expended, and lessons learned.

Section 11 – Load Growth, Transmission Projects, and Engineering

11.1 Load Growth

- The Commission should reject SCE's $1,031 million capital expenditure forecast for 2023-2028 associated with the Transportation Electrification Grid Readiness (TEGR) plan given SCE's flawed modeling approach used to develop the TEGR and significant locational and technical uncertainties associated with load forecasting, particularly for new technology groups such as medium- and heavy-duty electric vehicles.

- The Commission should adopt TURN's project specific reductions totaling $249.762 million to SCE's Base forecast for 2023-2028 to remove projects that have been cancelled, are delayed and duplicative, insufficiently scoped, or fail to demonstrate cost worthiness.

11.2 Transmission Projects
11.3 Engineering O&M

Section 12 – New Service Connections and Customer Requested System Modifications

12.1 New Service Connections

- The Commission should adopt TURN's forecast of residential, commercial, and agricultural new connections, instead of SCE's.
- The Commission should direct SCE to include housing completions in its models in the next GRC, in addition to or instead of housing starts, if SCE choses to forecast residential customers and new meters based on housing.
- The Commission should require SCE to provide all support for its customer and new connections forecasts in future GRCs in its direct testimony workpapers, including but not limited to modeling inputs.

12.2 Customer Requested System Modifications

- The Commission adopt revised forecast for Rule 20A Conversions in its rebuttal testimony.

Section 13 – Poles

13.1 Poles O&M
13.2 Poles Capital

Section 14 – Vegetation Management

14.1 Inspections Program

- The Commission should reject SCE's budget request and instead adopt TURN's proposed budget for Inspections of $52.122 m for 2025.
- The Commission should reject the SCE request to fund two types of simultaneous inspections and instead direct the utility to more efficiently manage the transition to remote sensing.
- The Commission should reject SCE's alternative Traditional Ground Inspections proposal.

14.2 Routine Line Clearing

- TURN recommends that the Commission reject the SCE proposal and instead adopt an adjusted forecast of $213.776 m.
- SCE's escalation percentage is inflated, and the Commission should instead adopt TURN's 2% escalation factor.
- SCE's inflated unit cost for routine line clearing should be adjusted downward to provide the promised efficiencies to ratepayers and to account for the impact of deep trims on unit costs.
- The Commission should reject Expanded Line Clearing costs as this program does not provide benefits that exceed its costs.

14.3 Dead, Dying, and Diseased Tree Removal

- TURN recommends that the Commission adopt a forecast of $25.108 m for dead, dying, and diseased tree removal.
- SCE's escalation percentage is inflated, and the Commission should instead adopt TURN's 5% escalation factor.
- SCE has provided no evidence of additional increased tree mortality, and the Commission should reject the request to expand the program.

14.4 Hazard Tree Management Program

- TURN recommends that the Commission reject SCE's proposed Hazard Tree Management Program. The program does not provide benefits that exceed the costs of the program and is not a reasonable use of ratepayer funds.

14.1 Seasonal Patrols/AOC/Emergent Work
14.2 Structure Brushing
14.3 Environmental Support for Vegetation Management
14.4 Wildfire Mitigation Vegetation Management Technology Solutions

Section 15 – Wildfire Management

15.1 Overview
15.2 Grid Hardening

- The Commission should approve a grid hardening forecast for the 2025-2028 period of 177 overhead miles converted to undergrounding and 1,651 miles insulated with covered conductor, as shown in the table in Section 15.2.6.3.

- For all 2025-2028 undergrounding projects, SCE should conduct the location-specific analysis described in Section 15.2.6.2 and should only implement projects where the analysis shows that undergrounding is the best alternative for that location.

- Ratepayers shall not be required to fund more than 177 overhead miles in 2025-2028. If SCE cannot justify undergrounding of 177 miles under the location-specific analysis and therefore undergrounds fewer miles, overhead hardening should be deployed on those miles. To the extent that SCE performs less than 177 miles of undergrounding and replaces those miles with overhead hardening, at the end of the rate case period, the difference in costs, based on the forecast unit costs adopted in this decision, should be refunded to ratepayers via the one-way balancing account that TURN recommends in Section 38.3 of this brief.

- The one-way balancing account that TURN recommends in Section 38.3 of this brief should have a separate one-way subaccount for undergrounding expenditures.

- The Commission should require SCE to submit an annual accountability report, similar to the report required in D.23-11-069. The report should require SCE to provide the results of its location-specific analysis for each undergrounding project it opted to pursue (including incomplete projects) in the preceding year. Consistent with the report required in D.23-11-069, SCE's annual report should also include information on completed undergrounding projects, including costs, unit costs, and overhead to underground conversion ratio information.

15.3 Emergent Technology and Inspections and Remediations
15.4 PSPS and Other Wildfire Activities

Section 16 – T&D Other Costs and Other Operating Revenue

16.1 T&D Other Costs

16.2 T&D Other Operating Revenues

Section 17 – Customer Service Operations

17.1 Billing and Payments

- The Commission should adopt all of the individual recommendations included in Ex. SCE-25, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

17.2 Customer Contacts

- The Commission should adopt all of the individual recommendations included in Ex. SCE-29, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

17.3 Customer Service Re-Platform
17.4 Customer Service-Related Other Operating Revenues
17.5 Billing Practices and Policies

Section 18 – Business Customer Services

18.1 Business Customer Services

- The Commission should adopt all of the individual recommendations included in Ex. SCE-26, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, Walmart, and SCE in its entirety.

18.2 Communications, Education, and Outreach

Section 19 – Customer Programs and Service

19.1 Customer Experience Management
19.2 Customer Programs Management

- The Commission should adopt all of the individual recommendations included in Ex. SCE-28, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

Section 20 – Business Continuation

20.1 Planning, Continuity, and Governance

20.2 All Hazards Assessment, Mitigation, and Analytics

- The Commission should adopt TURN's forecast for SCE's seismic retrofitting activities at non-electric facilities.

Section 21 – Emergency Management

21.1 Training, Drills and Exercises
21.2 Emergency Preparedness and Response
21.3 Storm Response

Section 22 – Cybersecurity

22.1 Cybersecurity Delivery
22.2 Grid Modernization Cybersecurity
22.3 Software License & Maintenance

Section 23 – Physical Security

Section 24 – Generation

- For hydro capital, adopt TURN's proposed forecast for 2024-2028 which was accepted by SCE in its rebuttal testimony but disallow $10 million relating to San Gorgonio decommissioning to reflect overcollections by SCE for work not performed in 5 previous GRC cycles.

- For hydro O&M, reduce SCE's hydro O&M forecast by $0.911 million ($2022) to reflect the use of a longer historical period (2016-2020) for calculating base year non-labor O&M and to account for expected delays in work due to the later anticipated issuance of new federal licenses for the Big Creek and Kaweah facilities.

- For Mountainview capital, reduce SCE's capital expenditure forecast of $17.692 million between 2023-2028 to reflect the removal of three capital projects from SCE's forecast, reduce allowable recovery by 25% for the Inlet Flow Distribution Grid project, and allow SCE to recover costs for the Turbine Generator Improvement program via a one-way balancing account with excess costs tracked in a memorandum account.

- For Peakers capital, reduce SCE's capital forecast by $2 million ($1 million in 2025 and $1 million in 2026) to reflect TURN's recommendation regarding the timing of relay replacements.

- For fossil generation decommissioning accruals, adopt the use of a 15% contingency (instead of SCE's assumed 20%), a change that would reduce decommissioning estimates by $13.167 million for Mountainview and $6.020 million for the Peakers.

- For fuel cells, the Commission should deny SCE any rate of return on $0.299 million in unrecovered capital due to the projects having been removed from service at the end of 2022.

- For solar O&M, reduce SCE's forecast by $2.75 million to reflect a 50% disallowance of lease payments and a lower expected escalation rate to reflect more reasonable inflation assumptions.

- For solar capital, reduce SCE's capital forecast by $40.65 million (2023-2028) by adopting a 50% disallowance of decommissioning capital costs and the use a 10% decommissioning cost contingency. Additionally, TURN recommends a $125 million disallowance (2023-2030) to SCE's revenue requirements to reflect a 50% disallowance of net book costs for prematurely retired facilities and no rate of return on any such costs allowed to be recovered in rates. SCE should be required to identify the amount of any stranded distribution plant associated with the retired solar facilities and be permitted to recover only 50% of that amount with no rate of return over 6 years.

- For Catalina capital, reduce SCE's capital forecast by $3.858 million (2023-2028) based on the removal of the solar carport project, the Battery Control System project, and repurposing of the microturbine space. Additionally, enforce a permanent disallowance of solar carport project costs due to SCE's violation of the Settlement Agreement adopted in D.22-11-007. The solar carports should not be assumed to be in service until early 2026.

- For Palo Verde O&M, reduce non-labor O&M by 6% to correct for sustained historic overforecasting and track costs in balancing account with overspending limited to 110% of the forecast value. Additionally, reduce non-labor O&M by $0.144 million by enforcing the longstanding requirement that 50% of Nuclear Energy Institute trade association dues be paid by shareholders.

Section 25 – Energy Procurement

25.1 Energy Procurement O&M
25.2 Energy Procurement Capital

Section 26 – Enterprise Technology

26.1 Technology Planning, Design, and Support
26.2 Technology Delivery
26.3 Digital and Process Transformation
26.4 Service Management Office and Operations

Section 27 – Operating Unit Capitalized Software

Section 28 – Enterprise Planning and Governance (Non-Insurance)

28.1 Financial Oversight and Transactional Processing

28.2 Legal

28.3 Business and Financial Planning

- The Commission should reduce SCE's forecast for Business Planning by $3.073 because SCE has failed to justify its non-labor forecast in light of consistently declining non-labor costs and underspending. The Commission should adopt TURN's forecast of $33.459 million, which includes SCE's request for an increase in labor but uses last recorded year for non-labor.

28.4 Supply Chain Management and Supplier Diversity and Development

Section 29 – Insurance

29.1 Liability Insurance (Wildfire)

29.2 Liability Insurance (Non-Wildfire)

- The Commission should adopt the proposed stipulation reached by TURN, SCE and Cal Advocates.

29.3 Property Insurance

- The Commission should adopt the proposed stipulation reached by TURN, SCE and Cal Advocates.

Section 30 – Employee Benefits, Training and Support

30.1 Employee Support

- The Commission should find the stipulation TURN, Cal Advocates and SCE reached and presented in Exhibit SCE-31, reasonable in light of the testimony submitted, consistent with law, and in the public interest.

30.2 Employee Benefits & Programs

- The Commission should reduce SCE's $120.406, Short-Term Incentive Program (STIP) forecast by $46.958 million, resulting in a forecast of $73.447 million by excluding 100% of the STIP costs for the Core Earnings, Capital Deployment and Clean Energy Transition goals and 50% of the STIP costs for the Covered Conductors and Operational Excellence (Catalyst) goals. This, in combination with no TURN objections to full funding of the remaining goals, results in 61% ratepayer responsibility for the STIP funding target. (Note: to implement this recommendation, a 39% reduction should be applied to the RO Model calculation, given that SCE's STIP forecast will ultimately depend on reductions that the Commission makes to the labor force in its GRC decision.)

- The Commission should order SCE to report each year of the rate-case cycle in a Tier 2 advice letter to show that it has made the forecasted conversion of STIP to Base Pay.

- The Commission should continue its policy of disallowing recovery of the Long-Term Incentive Program (LTIP) for the well-established reasons that the Commission has relied upon in past decisions, and reduce SCE's LTIP forecast by the full amount of $22.017 million.

- The Commission should reduce the 401(k) Savings Plan nominal forecast of $132.041 million down by $5.146 million to $126.895 million to ensure that the STIP-to-Base Pay conversion does not inappropriately result in unjustified, higher 401(k) costs for ratepayers. (Note: to implement this recommendation, a 4% reduction[2] should be applied to the RO Model calculation.)

- The Commission should reduce SCE's $153.788 million Medical Programs nominal forecast downward by $20.869 million for a forecast of $132.919 million to remove the unreasonable and unsupported increase to SCE's Total Compensation caused by SCE's premium-sharing redesign proposal. (Note: to implement this recommendation, a 16% reduction should be applied to the RO Model calculation.)

- Pensions: The Commission should authorize pension expense of $17 million, consistent with retaining the historical funding policy rather than adopting SCE's proposed new funding policy.

- PBOPs: The Commission should begin the process of exploring opportunities to put the more than $1 billion of overcollected PBOP assets to other permissible uses that would benefit SCE's ratepayers, and direct SCE to report on its activities to-date in this regard.

30.3 Employee Training

- The Commission should reduce the Training Seat Time activity forecast by $8.512 million from $37.023 million to $28.511 million to include the combined effects of lower expected training hours (for both existing and new-hire employees) and use a labor rate that disaggregates the overall average that SCE uses for all labor into one that differentiates between existing labor (which is naturally higher) and new hires (which are naturally lower). However, if the Commission agrees with SCE regarding the labor rate used in the Training Seat Time forecast, TURN's alternative forecast is $29.204 million.

- The Commission should reduce the Training Delivery forecast by $5.326 million from $23.189 million to $17.872 million to be consistent with the recommendation for lower Training Seat Time hours.

- Regardless of the Commission's decision on whether the particular forecast for Training Seat Time and Delivery is reasonable, the Commission should order SCE, either manually or dynamically within the RO Model, to reduce both the Training Delivery and Training Seat Time activities if the Commission makes reductions to any training-

[2] I.e., $5.146M / $126.895M.

impacted personnel on a prorated, percentage basis, that starts with the 2025 Test Year forecasts that the Commission adopts.

Section 31 – Total Compensation Study

Section 32 – Environmental Services

32.1. Environmental Services O&M

- The Commission should adopt the forecast of Environmental Services O&M recommended jointly by TURN, Cal Advocates, and SCE in Ex. SCE-30. The Commission should also clarify that the forecast authorized for Environmental Services O&M covers the costs and activities included in SCE's Environmental Services request presented in Exhibit SCE-06V06, none of which are eligible for tracking in SCE's VMBA or other wildfire mitigation accounts for potential future cost recovery.

32.2. Environmental Services Capital

- The Commission should adopt the forecast of Environmental Services Capital recommended jointly by TURN, Cal Advocates, and SCE in Ex. SCE-30.

32.3. SDG&E Request for SONGS-Related Cost Recovery re: marine mitigation

Section 33 – Audit Services

Section 34 – Ethics and Compliance

Section 35 – Safety Programs

Section 36 – Enterprise Operations

36.1 Transportation Services Department

36.2 Facilities and Land Operations

- The Commission should deny SCE's third request for funding for the Edison Training Academy, given prior funding authorizations in the 2018 and 2021 GRCs and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $11 million contingency.

- The Commission should deny SCE's third request for funding for the Vehicle Maintenance Facilities project, given prior funding authorization in the 2018 and SCE's failure to meet the Commission's requirements for additional funding in the 2021 GRC. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $2 million contingency.

- The Commission should deny SCE's second request for funding for the Alhambra Regional Operations Facility Renovations, given the prior funding authorization in the 2021 GRC and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $4.810 million contingency.

- The Commission should deny SCE's second request for funding for the Westminster Combined Facility Renovations, given the prior funding authorization in the 2021 GRC and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $3.216 million contingency.

- The Commission should deny SCE's request for funding for the San Jacinto Laydown Yard, given ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $1 million contingency.

Section 37 – Policy, External Engagement, and Ratemaking

37.1 Develop and Manage Policy and Initiatives

37.2 Education, Safety, and Operations

- The Commission should reject SCE's forecast of $7.630 million for Education, Safety and Operations because SCE underspent on this activity in every year from 2018-2023 and costs have consistently declined from 2019-2023. The more reasonable forecast is $6.193 million, based on last recorded year (2022).

37.3 Professional Education and Development

- The Commission should reduce SCE's forecast for Professional Education and Development to remove a greater portion of EEI dues than already excluded by SCE (an additional $0.770 million) and all dues for the California Taxpayers Association ($0.042 million), and authorize a forecast of $1.301 million.

37.4 Ratemaking Cost Recovery Business Planning Element

Section 38 – Results of Operations

38.1 Results of Operations

38.2 CPUC-Jurisdictional Revenue Requirement

38.3 GRC Ratemaking Proposals, including Memorandum and Balancing Accounts

38.3.1 Memorandum and Balancing Accounts

- The Commission should take reasonable steps to reduce reliance on memorandum and balancing accounts, and to ensure that amounts permitted to be recorded in such accounts receive appropriate reasonableness review before any rate recovery is authorized.

- The Commission should adopt a $10 million deductible that would routinely apply to new memorandum accounts.

- The Commission should reject SCE's proposed changes to the Wildfire Risk Mitigation Balancing Account/Grid Hardening Balancing Account, Vegetation Management Balancing Account, Electric Vehicle Infrastructure Memorandum Account, and Z-Factor Memorandum Account. The Commission should adopt TURN's proposed changes for each of these accounts.

- The Commission should reject SCE's proposals for the following new memorandum accounts: NextGen ERP SAP Memorandum Account, Advanced Metering Infrastructure 2.0 Memorandum Account, Cybersecurity Compliance Memorandum Account, and Historic Sporting Events Cost Tracking Memorandum Account.

- The Commission should deny SCE's request for rate recovery of the balance recorded in the Service Center Modernization Projects Memorandum Account due to the utility's failure to demonstrate the reasonableness of its above-authorized recorded costs.

- The Commission should reject SCE's proposal to seek rate recovery in this GRC of an amount for which rate recovery was specifically denied in the prior GRC as an abuse of the memorandum account mechanism, among other reasons.

38.3.2 SCE's Proposed "True-Up" of 2023 Recorded Capital Expenditures

- The Commission must reject SCE's proposal to treat recorded 2023 capital expenditures as *per se* recoverable even where opposed, in favor of continuation of the established practice of relying on the recorded figure only where there is no opposition to doing so.

38.4 Forecasts of Sales, Customers, and New Meter Connections

- The Commission should find that SCE's residential customer forecast relies on flawed regression analysis and an overly optimistic housing forecast and endorse TURN's forecast methodology instead.

38.5 Present Rate Revenue

38.6 Cost Escalation

38.7Other Operating Revenues (excluding Non-Tariffed Products and Services)

38.8 Other Operating Revenues – Non-Tariffed Products and Services

- The Commission should order SCE to maintain auditable "but for" tests and time logs at shareholder expense.
- The Commission should adjust the $16.72 million initial threshold for NTP&S that was established 25 years ago to account for inflation.
- The Commission should authorize the NTP&S Program for two more years, and if SCE wishes to continue its NTP&S program, it should be required to file an application containing at a minimum the same information PG&E is required to submit.
- The Commission should perform a comprehensive review of the NTP&S Program, including the outdated sharing mechanism.

38.9 Operation and Maintenance Expense Forecast

38.10 Overhead Allocation

38.11 Reinvestments in Utility-Owned Generation Resources

Section 39 – Rate Base

39.1 Plant in Service, Reserves, and Depreciation Expense

- The Commission should direct SCE to exclude from plant within its RO Model all costs recorded to memorandum accounts that the Commission has not found reasonable for recovery.

39.2 Working Capital (Excluding Customer Deposits)

- The Commission should find that if SCE fails to owe cash federal and state taxes again during this GRC cycle, then working capital should be revised to reflect a federal tax lag of 365 days and a state tax lag of 290 days.

39.3 Customer Deposits

- The Commission should maintain its longstanding practice and treatment of SCE's customer deposits and adopt $174 million as an offset to rate base.

39.4 Taxes

Section 40 – SCE Asset Depreciation Study

40.1 T&D Net Savage

- 40.1 The Commission should adopt TURN's recommended net salvage values, as they provide for increases that are consistent with the now-longstanding practice of applying gradualism for net salvage adjustments.

- The Commission should adopt TURN's recommended average service lives for the accounts TURN addressed, as they are based on a straightforward analysis without any need to rely on "statistically aged" or otherwise simulated data.

40.2 T&D Average Service Life
40.3 Small Hydro Decommissioning

- For small hydro decommissioning, prohibit SCE from accruing costs for any facility that has less than a 90% probability of being decommissioned.

40.4 Generation Decommissioning Escalation

- For both hydro and fossil decommissioning, accruals should be calculated using constant dollars ($2028) rather than SCE's proposal to use nominal dollars.

40.5 Solar PV
40.6 Fuel Cell Generation
40.7 Miscellaneous/Other

Section 41 – Post Test Year Ratemaking

- The Commission should find that TURN's two-part attrition mechanism meets the objectives of attrition and more reasonably balances the interests of ratepayers and shareholders during the post-test year period than SCE's proposal. TURN's mechanism resembles the Commission's original approach to attrition and escalates O&M expense using CPI-U, while addressing capital attrition with a 7-year average of recorded capital additions.

41.5 Z-Factor Deductible

- The Commission should increase the Z Factor threshold and deductible to $18 million to reflect inflation that has occurred since it was first adopted for SCE in the mid-1990s, or a slightly lesser amount for inflation since SCE first asked that the Z Factor be retained for cost of service ratemaking purposes.

Section 42 – Residential Disconnections and Arrearages

Section 43 – Compliance Requirements

Section 44 – Accessibility Issues

Section 45 – Results of Financial Examination by Cal Advocates

Section 46 – GRC Update Phase

Section 47 – Conclusion

2. LEGAL STANDARD– EVIDENTIARY STANDARDS AND BURDEN OF PROOF

The Commission is charged with ensuring that "[a]ll charges demanded or received by any public utility, … shall be just and reasonable" and cannot approve a rate change "except upon a showing before the commission and a finding by the commission that the new rate is justified."[3] In the test year 2009 GRC for SCE, the Commission succinctly described the utility's burden of proof that follows from these statutory mandates:

> As the applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of SCE showing. As the applicant in this rate case, SCE has the burden of proving that each of its proposals is reasonable.[4]

Thus, SCE has the burden of affirmatively establishing the reasonableness of all aspects of their application. This evidentiary burden is entirely the utility's; it is not up to intervenors to establish that the utility's forecast is unreasonable unless the Commission first determines that the utility has met its burden of proof with regard to that forecast.[5] In a recent rehearing decision, the Commission made clear that the utility's failure to meet its ultimate burden of proof could appear as a failure to make an adequate direct showing, or where it has failed to overcome reasonable doubts raised in other parties' showings.[6] And where the Commission is unable to

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[3] Cal. Pub. Util. Code Sections 451and 454.

[4] D.09-03-025, p. 8 (citing Sections 451 and 454, and D.06-05-016 (SCE Test Year 2006 GRC)), p. 7.

[5] D.21-11-036 (Rehearing decision in PG&E test yaer 2019 GT&S rate case), pp. 3-5.

[6] *See, e.g.,* D.09-03-025, p. 8; D.06-05-016, p. 7; D.01-10-031, pp. 8-9.

determine that the costs are just and reasonable, including because the utility failed to meet its burden of proof, it "can and must disallow those costs: that is, unjust or unreasonable costs must not be recovered in rates from ratepayers."[7]

The Commission's GRC review will also entail application of the "prudent manager standard" in order to determine whether SCE's costs are prudently incurred. It is a longstanding and well-established principle of California public utilities regulation that costs that result from a utility's imprudence are not reasonable under Section 451 and should not be recovered from ratepayers.[8] As the Commission emphatically stated in D.84-09-120, "it would be unconscionable from a regulatory perspective to reward such imprudent activity by passing the resultant costs through to ratepayers."[9]

The "prudent manager standard" applies whenever the "necessity of [the utility's] actions is called into question."[10]

> Under the prudent manager standard, the Commission does not evaluate reasonableness based on hindsight but based on what the utility knew or should have known at the time it made its decision. [citation to SCE TY 2021 GRC Track 3 decision] This standard reaches not just the activities

[7] D.18-07-025 (Rehearing of decision denying SDG&E rate recovery of wildfire claims costs), p. 5, quoting D.14-06-007.

[8] *See, e.g.*, D.12-12-030, pp. 61, 87 (disallowing recovery of proposed pressure testing costs for pipe segments for which PG&E lacks required records and further disallowing proposed costs of gas system records search and organization costs); D.09-06-027, pp. 35-36 (in a rate case decision, excluding from rate base the costs of a retaining wall for which the water utility failed to meet its burden of proof of demonstrating that the work would have been necessary in the absence of the utility's imprudence); D.01-06-047, p. 2 (disallowing Southwest Gas Company gas procurement costs based on imprudent managerial action); D. 95-12-046, 1995 Cal. PUC Lexis 959 (disallowing costs associated with the utility's imprudent long-term commitment to interstate gas pipeline capacity); D.94-03-048, 53 CPUC 2d 452, 456 (holding that it is not reasonable to pass on to Southern California Edison ratepayers costs resulting from the Mojave Coal Plant accident); D.85-08-102, 18 CPUC 2d 700, 715-716 (holding that ratepayers are not responsible for bearing the consequences of PG&E's imprudence with respect to the Helms Pumped Storage Project).

[9] D.84-09-120, 16 CPUC 2d 249, 283.

[10] D.23-11-069 (PG&E TY 2023 GRC), pp. 25-26.

> and associated costs for which [the utility] seeks recovery here but extends to the actions or inactions that resulted in these activities being necessary.[11]

Here, the standard will apply to determining the reasonableness of both recorded costs from periods preceding the 2025 test year, and also the cost forecasts for the 2025 test year and the rest of the rate case period to the extent the associated activities and spending are necessitated by utility imprudence. That is, to the extent spending in the GRC period was made necessary due to prior SCE actions or inactions that influenced the need for the spending, the prudent manager standard is implicated, and SCE must meet its burden of demonstrating the prudence of said actions or inactions.

In D.17-11-033, denying SDG&E rate recovery of costs related to the 2007 wildfires, the Commission described the prudence standard:

> The Commission's standard for reasonableness reviews, reaffirmed in a series of decisions, is as follows: The term reasonable and prudent means that at a particular time any of the practices, methods and acts engaged in by a utility follows the exercise of reasonable judgment in light of the facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost effectiveness, safety and expedition.[17]

Thus, in determining whether SCE met the prudent manager standard in this proceeding, the Commission will need to take a number of factors into consideration. First and most obviously, it will need to assess the quality of the evidence put forward by the utility. In order to meet its burden the utility must present sufficient direct evidence in support of its rate recovery request. For example, simply presenting recorded balances in memorandum accounts would not

[11] *Id.*

establish the prudence of the underlying utility actions. Instead, SCE must provide sufficiently detailed evidence to justify rate recovery of recorded costs in excess of any amounts found reasonable in past decisions. Reliance on utility-produced scheduling and planning documents is insufficient, as such information "does not automatically establish the reasonableness" of the program or project spending in question.[12] The utility needs to demonstrate that the costs were incurred prudently and that it made best efforts to contain costs, with the cost overruns explained and demonstrated to be reasonable.

Similarly, to meet its prudence burden, SCE must show that its actions were at the lowest reasonable cost consistent with good utility practices. And a key element of good utility practices is cost effectiveness. Thus, making sure that SCE incurred the claimed costs wisely and cost-effectively is fundamental to the prudence standard that SCE must satisfy.

Finally, in applying the prudent manager standard, the Commission has held that it will expect the utility's managers to exercise "proportionately greater care" to decisions involving large amounts of money, greater levels of uncertainty, or high degrees of risk.[13] Exercising greater care, however, is not the equivalent of simply doing more work; it is a recognition that each ratepayer dollar should be put to its best use.

As for the standard of proof in this GRC, the Commission currently requires utilities to meet the "preponderance of the evidence" standard of proof in rate cases.[14] Under that standard,

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[12] D.21-11-036 (Rehearing decision in PG&E test year 2019 GT&S rate case), pp. 10-11.

[13] D.89-02-074, 31 CPUC 2d 236, 246. See also D.85-08-102, 18 CPUC 2d 700, 710-711 (where tasks undertaken are of such enormity to expose the utilities and potentially ratepayers to substantial financial risks, utilities must exercise "even greater care and managerial acumen" than would be called for in ordinary circumstances; rejecting view that "marginal" or "average" performance was required and holding the utility to a "good performance" standard).

[14] D.14-12-025, p. 21.

the applicant must establish the reasonableness of every aspect of its request with evidence that, "when weighted with that opposed to it, has more convincing force and the greater probability of truth."[15]

3. POLICY

3.1 The Commission Should Take Steps To Ensure Transparency In Light of the Growing Reliance on Machine Learning-Based Modeling Methods.

The Commission is seeing a significant and growing reliance on machine learning (ML) models as the basis for forecasts of program activities and associated reliability and safety benefits.[16] These models may range from simple Ordinary Least Squares (OLS) models to more complex supervised learning frameworks for classification and regression tasks such as Random Forests (a model used in this GRC application).

To get a flavor for what the use of these models looks like in just one program within the GRC context, the Commission should consider SCE's response to a TURN data request asking about a passage in the utility's workpapers describing the development of the scope of its proposed Overhead Conductor Program as part of its Infrastructure Replacement activities.[17] The workpaper passage said,

> The program scope was informed by a machine learning algorithm utilizing a multitude of mechanical, electrical and environmental attributes to estimate the risk and consequence of failure for each of the 500,000+ overhead conductor segments on the SCE distribution system.

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[15] D.21-08-036 (SCE TY 2021 GRC), pp. 9-10, *citing* D.08-12-058, p. 19 (citing Witkin, Calif. Evidence, 4th, Vol. 1, 187).

[16] TURN discusses the ML models used for SCE's Overhead Conductor Program and Underground Cable Replacement Program in Sections 6.1.1 and 6.1.2 of this brief.

[17] TURN-SCE-072, Q3

> The output of the algorithm was then used to select 1,680 of the higher risk circuit miles population for replacement.[18]

TURN sought further information regarding not only the models used but also the models considered but not used. SCE's response is daunting to mere mortals, even those with extensive experience in the utility regulatory process. It includes a high level description of the ML models and sub-models used, and a reference to use of the "Receiver Operating Characteristic (ROC) and Area Under the Curve (AUC)" as "metrics used to determine model algorithm selection, feature selection, and hyperparameter tuning."[19] When asked to specify the outcome variables for the ML model, SCE began with a relatively straightforward statement that even an attorney could understand: "The output of all of SCE's machine learning models is probability of failure for a given asset within an asset class." But the further explanation that followed was not so straightforward, at least to those not steeped in how such models are designed and operate:

> The random forest algorithm statistically determines the probability based on constructing a collection or "ensemble" of decision trees. These decision trees are constructed by taking multiple bootstrap samples from historical data. For prediction, each of these decision trees casts a "vote" for whether an asset was a part of the failing or passing class in their bootstrapped data set. Due to the random sampling and sub-setting of data used for decision tree creation and because these trees create decision boundaries across many different variables, the ML model does not have a smooth, continuous functional representation.[20]

[18] Ex. TURN-05-E, Attachment 2, Response to TURN-07, Question 3(a-f), at pages 85 to 91 of 96 in the PDF file. The same material is contained in Ex. SCE-13, Vol. 1, Appendix A, pp. A11 to A17.

[19] *Id.*, response to TURN-07, Question 3.b.

[20] *Id.*, response to TURN-07, Question 3.c.

There are charts showing how each variable for the model is ranked, but the variables are listed in what appears to be coding format (with no description), and nothing approaching plain English.[21]

In sum, TURN submits the description of the information and process involved in this single instance of SCE relying on ML to support its infrastructure replacement proposal makes clear that the Commission, its staff, and interested parties can no longer rely on past practices to effectively assess the utility's showing. And perhaps the even more troubling part of SCE's description is its assertion that the utility considered other model algorithms, but determined "there was no appreciable accuracy improvement."[22] If the Commission cedes to the utility the role of selecting which model's results go forward, without an effective process for comparing and contrasting the results of other models considered but not selected, the agency's regulatory oversight risks becoming compromised, as there may be no clear pathway for intervenors and Commission staff to understand or scrutinize these models.

The Commission has tools to ensure that the agency and interested parties have sufficient access to the full range of model inputs (data, assumptions), the process by which the utility selected the model it relies upon to the exclusion of other available alternatives, and the outcomes produced by not only the model the utility chose to rely upon, but also the others it considered or assessed. Public Utilities Code Sections 1821 and 1822 and Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure are designed to avoid having the Commission's decisions rely on "black box" processes. However, those provisions date from years ago and were initially designed for simpler closed-form models which, in comparison to

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[21] *Id.*, response to TURN-07, Question 3.d.

[22] *Id.*, response to TURN-07, Question 3. b.

today's multivariate, sophisticated ML-based models, might now seem relatively rudimentary. Therefore, it is appropriate for the Commission to specify requirements for SCE's next GRC showing in order to ensure that the transparency of and access to its ML-based and similar analytical process achieves consistency with the longstanding standards.

First, to foster a transparent review process in future GRCs, the Commission should require SCE to submit working ML models following the traditional peer review protocol, and to do so no later than the outset of the GRC process. All such information should be provided as part of the Master Data Request response. This should include, at a minimum, access to the operational models (in Python, RStudio, or other applicable software), labeled datasets that the model is trained on, and the ability for stakeholders to run and test these models under varied assumptions to gauge each model's robustness and sensitivity, aligning with Section 1822(a).

Second, it is crucial that SCE provide not only the final outputs of these models but also details on the inputs, variable descriptions, test/train dataset split and the specific model used wherever ML models are used. This full disclosure should include a descriptive explanation of why the utility chose certain models over others, as well as a transparent analysis of the models' performance through metrics such as ROC, AUC, R^2 and other precision and accuracy metrics.

Finally, the Commission should encourage the utility to opt for simpler, more efficient models when the trade-off between model complexity and performance suggests that a less complex model provides comparable performance metrics without the opacity or computational demands of more complex, 'black box' models. . This approach would support easier verification and engagement by stakeholders and Commission staff, ensuring that the application of machine learning aids rather than obfuscates utility regulation and oversight.

By adopting a framework that includes ML modeling best practices, the Commission will not only enhance the accountability of SCE's use of advanced modeling techniques but move toward promoting a standard of openness that aligns with technological advancement and regulatory integrity.

3.2 The Commission Must Reject SCE's Proposal to Treat Recorded 2023 Capital Expenditures as *Per Se* Reasonable and Prudent, Even Where Opposed by Other Parties.

SCE's rebuttal testimony unveiled the utility's proposed treatment for recorded 2023 capital expenditures, which the utility argues should be subject to a "true-up" treatment across the board. Where the recorded amounts for 2023 are greater than the utility's forecast for that year, SCE would not be required to establish the reasonableness of the additional increment; rather, it would be enough to show that the utility had spent the money on assets that are used and useful. Reasons for disallowance of such costs would be limited to "imprudence," a term SCE's testimony does not define for this purpose, and any intervenor seeking such a disallowance would have to meet a "heavy burden of persuasion."[23]

TURN more fully addresses the lack of merit to SCE's proposal in Section 38.3 of this brief (GRC Ratemaking Proposals). However, given the extreme policy shift reflected in aspects of SCE's proposal, particularly the proposed shift in the evidentiary burden, TURN thought it wise to flag the issue in the policy section of the brief as well.

[23] Ex. SCE-18, Vol. 1, pp. 114-117.

4. AFFORDABILITY AND EQUITY

4.1 Affordability

The Commission has repeatedly stated that "[w]ater, energy, and telecommunications services should be affordable,"[24] recognizing that "Californians rely on utility services, including electricity, gas, water, and telecommunications, to live and work."[25] Without energy services, families cannot conduct many of the necessary activities of life – refrigerate groceries, cook regular meals, bathe in warm water, or study and work at night with appropriate illumination. In Senate Bill 598 (2017), the California Legislature formally declared that living without basic gas or electric utility service "causes tremendous hardship and undue stress, including increased health risks to vulnerable populations."[26] Yet, there can be no doubt that due to high and increasing rates, energy services are not fully accessible to every Californian. The pace of increase in SCE's rates and bills is unsustainable not only from a policy standpoint, but from a moral one because the services SCE provides are life necessities.

Despite clear legislative and regulatory intent to enable universal access to essential energy services, SCE requests incremental base revenue requirement increases of $1.7 billion (20%) in 2025,[27] $620 million (6%) in 2026, $660 million (6%) in 2027, and $700 million (6%) in 2028.[28] This translates to more than $10 billion additional funding from ratepayers over this 2025 GRC cycle. SCE's request is on top of increases of 16% that have already been authorized

[24] CPUC website: Affordability Rulemaking available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

[25] Order Instituting Rulemaking 18-07-006, p. 3.

[26] Senate Bill 598 (2017), Sec. 1(c).

[27] Ex. TURN-02E, p. 1, citing SCE 2025 GRC Application (A.23-05-010).

[28] Ex. TURN-02E, p. 1, citing SCE 2025 GRC Application (A.23-05-010).

since 2022. As shown below, based on SCE's request, by 2028 SCE's base revenues will have increased by nearly 70% cumulatively since 2022. These figures do not consider any past or future authorized increases, other revenue proceedings, or the impact of balancing account true ups and cost of capital adjustments.

SCE's GRC Revenues (2022-2028)[29]

SCE's Historical and Proposed GRC Base Revenue Requirement

Values in $000s unless indicated	Jan-22	Mar-22	Jan-23	Mar-23	Jun-23	Oct-23	Jan-24	2025 Req	2026 Req	2027 Req	2028 Req	Totals
	(1)	(1)	(2)	(2)	(3)	(4)	(4)	(5)	(5)	(5)	(5)	
GRC Base RRQ	**$ 7,259,200**	**7,259,220**	**7,792,632**	**7,702,857**	**7,633,108**	**7,633,108**	**8,582,245**	**10,266,672**	**10,885,338**	**11,548,972**	**12,253,484**	**$ 68,588,543**
Increase - $	-	$ 20	533,432	(89,775)	(69,749)	-	789,613	1,684,427	618,666	663,634	704,512	$ 4,834,760
Inc. Increase-%	-	0.0%	7.3%	-1.2%	-0.9%	0.0%	10.3%	19.6%	6.0%	6.1%	6.1%	68.8%
Cum Increase -%	-	0.0%	7.3%	6.1%	5.2%	5.2%	16.0%	39.2%	47.8%	56.9%	66.6%	66.6%

Sources:
(1) AL 4719-E p. 2.
(2). AL E_4997-E p.3.
(3) AL E_5041-E, p. 3
(4). AL E_5149-E-A p.5.
(5) SCE 2025 GRC Application, p. 7., Table 1

The Commission must not just address, but also *arrest* current trends of rising electricity rates well in excess of the growth of household incomes, unprecedented capital spending levels, and the proliferation of revenue adjustments that by their sheer volume and number make it difficult to keep track of why rates are rising and affordability declining.

4.1.1 The Commission Should Find that Current Levels of Energy Rates and Bills Are Not Affordable for Many Low-Income Customers Despite Low-Income Assistance Programs

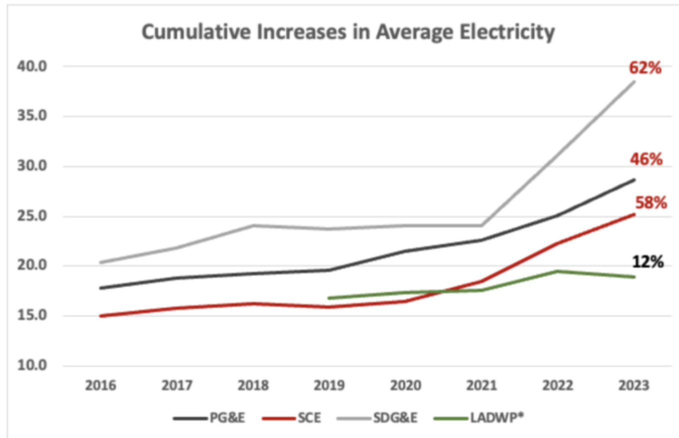
For SCE and for other California IOUs, 2019-2024 describes a period of truly astonishing rate and revenue increases as shown below.

[29] Ex. TURN-02E, p. 2.

Recent History of Electricity Rate Increases[30]

Bundled SAR
(Jan 1 per kWh Res. Avg. Rate)

	PG&E	SCE	SDG&E	LADWP*
2016	17.8	**15.0**	20.4	
2017	18.8	**15.8**	21.8	
2018	19.2	**16.2**	24.0	
2019	19.6	**15.9**	23.7	16.8
2020	21.5	**16.4**	24.1	17.4
2021	22.6	**18.5**	24.0	17.6
2022	25.1	**22.3**	31.1	19.5
2023	28.6	**25.2**	38.5	18.9
2016-2019 % Incr.	10%	**6%**	16%	
2019-2023 % Incr.	46%	58%	62%	12%



Notes:
IOU data from annual consolidated and true up advice letters.
** LADWP Rates based on assumed 500 kWh per month average usage and tier 1 total energy charge*
(Source: https://rates.ladwp.com/UserFiles/Rate%20Summaries/Simplified%20Electric%20Rates/Simplified%20Electric%20Rates%20Jan%202019%20-%20Jun%202023.pdf)

The cumulative increase in SCE's system average bundled residential electricity rate from 2019 to 2023 is nearly 46%. By comparison, the cumulative rate of CPI-U over 2019-2023 has been roughly 21%[31] for the Los Angeles area and 18%[32] for California overall. This would indicate that from 2019 to 2023, SCE customers have faced a *real* increase in electricity costs of roughly 25%.[33]

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[30] Ex. TURN-02E, p. 3, citing Ex. SCE-07, Vol 4, Figure II-2, p. 11.

[31] Ex. TURN-02E, p. 4, citing https://www.dir.ca.gov/oprl/cpi/entireccpi.pdf. Calculation: (310.4-263.0)/263.0=18%

[32] Ex. TURN-02E, p. 4, citing https://www.dir.ca.gov/oprl/cpi/entireccpi.pdf. Calculation: (310.4-263.0)/263.0=18%

[33] Ex. TURN-02E, p. 4, citing US Bureau of Labor Statistics, Western Information Office Los Angeles-Long Beach-Anaheim data available at: https://www.bls.gov/regions/west/news-release/consumerpriceindex_losangeles.htm. (Calculation: Jan 2024 CPI - Jan 2019 CPI)/Jan 2019 CPI, (326.640-269.468)/269.468=21.2%

Among actions supporting affordability, SCE cites assistance programs such as CARE and FERA. SCE states that as of year-end 2020, over 25% of SCE residential accounts are receiving CARE subsidies to help pay their electric rates. This is out of about 28% eligible households across SCE's service territory. Nonetheless, roughly 150,000 of SCE's low-income customers are not receiving support from the CARE program even though eligible.[34] Based on 2022 data, only 12% of eligible households are receiving assistance from FERA, leaving about 350,000 eligible households unserved by CARE and FERA.[35] In addition to the customers eligible for CARE or FERA but unenrolled, many customers have incomes too high to qualify for energy assistance but too low to absorb the increases in electricity rates and bills without making tradeoffs among necessities. Thus, they fall though the CARE/FERA assistance gap.

4.1.1.1 CARE/FERA Income Gap Demonstrates that Low-Income Programs Do Not Fully Address the Need for Assistance.

Self-Sufficiency Standard (SSS) calculators are bottoms-up, budgetary estimates of the level of household income necessary to pay all household costs without the need for any public assistant program.[36] The SSS income is frequently greater than the highest income qualifying for CARE or FERA which are set at 200% and 250% of the state poverty level respectively.[37] Thus, comparing SSS income to CARE and FERA limits demonstrates what TURN calls the "Assistance Gap." At income levels in the Assistance Gap, households lack income sufficiency to pay all household costs timely each month, but earn too much to qualify for low-income

[34] Ex. TURN-02E, p. 12.

[35] Ex. TURN-02E, p. 13.

[36] Ex. TURN-02E, p. 13.

[37] Ex. TURN-02E, p. 13.

energy subsidy programs. The figure below shows that the CARE/FERA "Assistance Gaps" have widened since 2018. For example, in 2018 in Riverside County, the self-sufficiency income for a family of three people consisting of two adults and a school-aged child was about $50,000, roughly the minimum to make ends meet every month, but not a great deal more. In 2018, $50,000 in income still allowed that family to qualify for FERA, making electricity a bit less expensive, and freeing up that incremental saving for other necessities. In 2023, the self-sufficiency income is at $96,000,[38] but the same family makes too much money to receive subsidy, even though it is still just getting by economically. This means that the family will have to make more trade-offs between essential services in order to remain within its finite budget. In this respect, all essential services that increase in real terms become less affordable.

Increasing Households in the CARE/FERA "Assistance Gap"[39]

(in $)	2018					2023				
County	2018 SSS (1)	2018 CARE Theshold (2)	2018 FERA Theshold (2)	2018 CARE Income Gap	2018 FERA income Gap	2023 SSS (3)	2023 CARE Theshold (4)	2023 FERA Theshold (4)	2023 CARE Income Gap	2018 FERA income Gap
Fresno	$45,756	$40,840	$51,050	($4,916)	$5,294	$80,784	$49,720	$62,150	($31,064)	($18,634)
Imperial	$45,908	$40,840	$51,050	($5,068)	$5,142	$80,088	$49,720	$62,150	($30,368)	($17,938)
Inyo	$45,051	$40,840	$51,050	($4,211)	$5,999	$89,072	$49,720	$62,150	($39,352)	($26,922)
Kern	$44,522	$40,840	$51,050	($3,682)	$6,528	$79,140	$49,720	$62,150	($29,420)	($16,990)
Kings	$45,683	$40,840	$51,050	($4,843)	$5,367	$80,436	$49,720	$62,150	($30,716)	($18,286)
Los Angeles	$59,936	$40,840	$51,050	($19,096)	($8,886)	$106,116	$49,720	$62,150	($56,396)	($43,966)
Madera	$47,938	$40,840	$51,050	($7,098)	$3,112	$84,804	$49,720	$62,150	($35,084)	($22,654)
Mono	$55,414	$40,840	$51,050	($14,574)	($4,364)	$99,896	$49,720	$62,150	($50,176)	($37,746)
Orange	$64,584	$40,840	$51,050	($23,744)	($13,534)	$114,951	$49,720	$62,150	($65,231)	($52,801)
Riverside	$50,028	$40,840	$51,050	($9,188)	$1,023	$96,072	$49,720	$62,150	($46,352)	($33,922)
San Bernardino	$49,020	$40,840	$51,050	($8,180)	$2,030	$91,212	$49,720	$62,150	($41,492)	($29,062)
Santa Barbara	$58,008	$40,840	$51,050	($17,168)	($6,958)	$120,449	$49,720	$62,150	($70,729)	($58,299)
Tulare	$45,191	$40,840	$51,050	($4,351)	$5,859	$80,760	$49,720	$62,150	($31,040)	($18,610)
Tuolumne	$53,734	$40,840	$51,050	($12,894)	($2,684)	$91,477	$49,720	$62,150	($41,757)	($29,327)
Ventura	$65,785	$40,840	$51,050	($24,945)	($14,735)	$111,238	$49,720	$62,150	($61,518)	($49,088)

[38] Ex. TURN-02E, p. 14.

[39] Ex. TURN-02E, p. 14, citing TURN DR_01.

4.1.1.2 Even Middle-Income Customers May Make Budget Trade-Offs to Pay for Essential Utility Services.

Similar to the CARE/FERA Assistance Gap, TURN compared SSS to the median income in each county in SCE's service territory. This comparison highlights areas where the median income, in all cases too high to receive CARE or FERA assistance, is actually *below* the SSS income for the area. This means that customers whose income approximates AR_{50} are just getting by economically. The figure below shows the margin above SSS income at median income (roughly 50 percentile) and "moderate income" defined as 120% of median based on 2023 HUD data by California county.

2023 Margin of Median and Moderate Income Above "Self-Sufficiency"[40]

(Monthly Income in $)	2023				
County	**2023 SSS (1)**	**HUD Median Income (4)**	**HUD Moderate Income (2)**	**Median Margin Over SSS**	**Moderate Income Margin Over SSS**
Fresno	$6,732	$6,283	$7,542	($449)	$810
Imperial	$6,674	$6,283	$7,542	($391)	$868
Inyo	$7,423	$6,404	$7,688	($1,019)	$265
Kern	$6,595	$6,283	$7,542	($312)	$947
Kings	$6,703	$6,283	$7,542	($420)	$839
Los Angeles	$8,843	$7,367	$8,754	($1,476)	($89)
Madera	$7,067	$6,283	$7,542	($784)	$475
Mono	$8,325	$7,183	$8,621	($1,141)	$296
Orange	$9,579	$9,583	$11,500	$4	$1,921
Riverside	$8,006	$7,088	$8,504	($919)	$498
San Bernardino	$7,601	$7,088	$8,504	($514)	$903
Santa Barbara	$10,037	$8,046	$9,658	($1,992)	($379)
Tulare	$6,730	$6,283	$7,542	($447)	$812
Tuolumne	$7,623	$7,329	$8,796	($294)	$1,173
Ventura	$9,270	$9,263	$11,117	($7)	$1,847

Sources:
(1) Based on 2 adults and one school-aged child. SSS taken as the lower of MIT Living Wage Calculator or Family Budget Calculator (https://laborcenter.berkeley.edu/living-wage-and-self-sufficiency-tools-and-data/)
(2) 3 person household data HUD Median and Moderate Income Data per 2023 State Income Limits, dated June 6, 2023, available at: https://www.hcd.ca.gov/sites/default/files/docs/grants-and-funding/income-limits-2023.pdf

In a number of counties, moderate income (120% of median) is insufficient! In Los Angeles monthly income of nearly $9,000 per month is "just making it" economically, right at SSS. This underscores TURN's assertion that even at middle-income levels, there is little margin in household budgets to absorb rate increases that are higher than inflation.

4.1.1.3 Disconnection Caps Should Be Maintained Indefinitely

As TURN has asserted in the Disconnections OIR (R18-07-005) and other proceedings touching on the issues of affordability and the accessibility of essential energy services, the level

[40] Ex. TURN-02E, p. 15.

of IOU payment arrearages is an indication of the level of threat to customers' energy security. The Commission has also recognized: "The number of customers in arrears for non-payment of electric and gas bills is an indicator or a risk factor for customer disconnections and can be a proxy for the baseline number of people who could have their electricity or gas service disconnected."[41] Since December 2018, the level of customer arrearages in dollars has increased nearly tenfold. Data shows that the number of customers in arrears has declined but the total dollars have increased indicating that those in arrears are further behind.

Changes in Residential Arrearages 2023 vs. 2018[42]

SCE Arrearages >30 days (in $)

	December-18	December-23	Dollar Change	% Change
Dollar Amount Res	$82,623,852	$862,053,149	$779,429,297	943%
Non-CARE/FERA	$54,456,112	$513,347,981	$458,891,869	843%
CARE/FERA/Medical Baseline	$28,167,740	$348,705,168	$320,537,428	1138%
# of Res. Customers	1,149,389	922,406		
Non-CARE/FERA	636,092	543,100		
CARE/FERA/Medical Baseline	513,297	379,306		

Sources:
Data extracted from SCE Monthly Disconnect Data Report _ 012019 (R.1807005) and R1807005_SCE Monthly Disconnect Data Report December 2023

Prior to the Disconnections OIR (R.18-07-005), all California IOUs experienced a surge in disconnections from 2010 through 2018 when the disconnections cap was put into place, but the experience of SCE customers was notable in that its shutoff rates approached 10% of residential customers.[43] Shutoffs fell disproportionally on FERA customers (a 48% increase from 2010-2016 in SCE's service territory)[44] and customers whose income was too high to

[41] R.18-07-005, Disconnections OIR, Attachment 1, pp. 1-14.

[42] Ex. TURN-02E, p. 16.

[43] Ex. TURN-02E, p. 17.

[44] Ex. TURN-02E, p. 17.

qualify for CARE or FERA.[45] To help customers maintain energy security despite the trend of dramatically rising rates, the Commission should find in this proceeding that given the magnitude of SCE's request and the fact that rates are already unaffordable for some customers, its disconnection cap of 4% should remain in place indefinitely.

Absent a continuation of the disconnections cap, TURN is concerned that the volume of arrearages will incentivize SCE and other IOUs to increase disconnections activity again. This would be detrimental to the energy security of customers.

4.1.1.4 SCE's Ballooning Capital Spend Obscures the Full Price Tag During the Early Years and Exacerbate the Affordability Crisis Later

SCE proposes capital spending of nearly $8 billion annually[46] for each of the four years of its 2025 GRC cycle. SCE projects that by 2028 this investment will increase its weighted average rate base by nearly 50% relative to 2023.[47] As a result, the equity return component of the revenue requirement will grow nearly $1.5 billion by 2028.[48] SCE's capital investment produces an incremental 5 cents in annual earnings per share for every additional $100 million of capital spending,[49] creating a powerful incentive for SCE to spend as much capital as it can apply to its operations.

[45] Ex. TURN-02E, p. 17.

[46] Ex. TURN-02E, p. 4, citing Ex. SCE-07 Vol2 (Results of Operations) WP 32.

[47] Ex. TURN-02E, p. 4, citing EIX Fourth-Quarter and Full-Year 2023 Financial Results, dated February 22, 2024, p 13, available at: https://www.edison.com/investors/events-presentations. %

[48] Ex. TURN-02E, p. 5.

[49] Ex. TURN-02E, p. 5, citing EIX Fourth-Quarter and Full-Year 2023 Financial Results, dated February 22, 2024, p 27, available at: https://www.edison.com/investors/events-presentations

SCE characterizes every dollar of its proposal as essential for safety, reliability and the advancement of California climate policy. But the Commission must scrutinize SCE's request with the recognition that there may be conflicting interest between shareholders and ratepayers. Also, customer affordability constrains the level of utility spending that is prudent – and even possible. "The Commission has emphasized that, 'a key element of finding a charge or rate just and reasonable is whether that charge or rate is affordable.'"[50] Given the enormous amounts of capital spending proposed, the Commission should heed its own admonishment. "Moreover, in considering the amount of funding to authorize the Commission must balance safety and reliability with affordability and reasonable rates."[51]

A powerful step in balancing potentially conflicting interests is to increase transparency surrounding the full cost of capital investment programs. Multi-year capital spending initiatives generate large amounts of bonus and accelerated depreciation. Due to the significant volume of tax timing differences for ratemaking versus book recovery, capital spending reduces revenue requirements in the early years of the investment's useful life.

The significantly lower cost recovery in early years, however, obscures the full price tag of the utility's proposal. The full ratepayer cost of the capital spending may not be apparent until well into and beyond the GRC cycle in which the spending was authorized. As TURN has raised before, this results in a "pancaking of capital" on ratepayers' bills for the capital expenditures as well as their associated equity return on rate base and taxes. As the Commission explained in its 2021 Report, *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*:

[50] D.21-08-036, p.19 citing D.19-05-020 at 11.

[51] D.21-08-036, p.41.

> The growth in rates can be largely attributed to increases in capital additions driven by rising investments in transmission by PG&E and distribution by SCE and SDG&E. While the utilities have made major financial commitments to wildfire mitigation and transportation electrification, these costs have not been fully reflected in rates so far.[52]

For example, SCE's expected *federal* tax depreciation adjustments (shown below) are increasing over the GRC cycle due to increasing capital spending.

Estimated Revenue Req Reduction from Federal Tax Depreciation [53]

Federal Depreciation Tax Adjustments (in $000)	Recorded 2022	Estimated						
		2023	2024	2025	2026	2027	2028	Totals
Federal Tax Depreciation	$ 2,703,331	$ 2,986,834	$ 3,251,764	$ 3,592,159	$ 3,831,920	$ 4,079,403	$ 4,434,426	**$ 24,879,837**
Federal Cash Effect	567,700	627,235	682,870	754,353	804,703	856,675	931,229	**$ 5,224,766**

Source: WP SCE-07, Vol. 2, Book B, p. 40. (Table A-4.17); Federal cash effect assumes 21% corporate tax rate.

For the 2025 GRC cycle alone, TURN estimates there will be temporary revenue requirement reductions due to *federal tax depreciation* of nearly $16 billion, all things being equal. This amount does not include state tax depreciation benefits and as such understates the magnitude of the potential reductions in revenue requirement. These depreciation timing differences, however, will "reverse" and ratepayers will have to pay them back through higher revenue requirements in the future. As long as capital expenditures remain large and increasing, new depreciation savings will offset the reversal of tax benefits in the revenue requirement, but rate base (and customer's obligation to fund return on rate base) will grow. And this will be reflected in higher general levels of utility revenues and rates.

> "…rate base has a direct relationship with the return on rate base revenue requirement that is recovered from ratepayers. The return on rate base revenue requirement reflects the opportunity for the IOU to earn a profit. Return on rate

[52] CPUC, "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), p. 7.

[53] Ex. TURN-02E, p. 6.

> base may represent a return to shareholders paid by ratepayers; however, having a set rate of return ensures that IOUs are able to raise sufficient capital to make improvements to infrastructure and provide safe and reliable service to all customers. On the flip side, by having a set rate of return, IOUs are inherently incentivized to make investments to drive an increase in their rate base and therefore, their profitability.[54]

With SCE's 2025 proposal, total annual capital spending has increased from figures in the $4 to $5 billion range to planned spending that exceeds $8 billion in a single year.[55] Given the proliferation of capital spending, it is important to increase cost transparency for all stakeholders.

In the illustration shown below (Figure 4), including only federal tax effects, SCE's proposed capital spending would create an apparent reduction to revenue requirements of nearly $3.5 billion or an average of more than $800 million per year, compared to normalized recovery. Although ratepayers may not feel the effects of SCE's massive capital program during this GRC cycle, SCE's shareholders are expected to enjoy 6 to 8% compound annual growth in rate base (and earnings, all else equal).

Estimated Revenue Req Reduction of State and Federal Tax Depreciation

Values in $000s unless indicated	2022 (1)	2023 (2)	2024 (3)	2025 (3)	2026 (3)	2027 (3)	2028 (3)	Totals
GRC Base RRQ	**$ 7,259,200**	**7,792,632**	**8,582,245**	**10,266,672**	**10,885,338**	**11,548,972**	**12,253,484**	**$ 68,588,543**
Inc. Increase in RRQ	-	533,432	789,613	1,684,427	618,666	663,634	704,512	**4,994,284**
Plus Cash Effect of Tax Depreciation	567,700	627,235	682,870	754,353	804,703	856,675	931,229	5,224,766
Normalized GRC RRQ (w/o depreciation benefits)	**$ 7,826,900**	**$ 8,419,867**	**$ 9,265,115**	**$ 11,021,025**	**$ 11,690,041**	**$ 12,405,647**	**$13,184,713**	**73,813,309**
Dollar Increase in RRQ	-	592,968	845,248	1,755,910	669,016	715,605	779,067	**5,357,814**

Sources:
(1) AL 4719-E p. 2.
(2). AL E_5149-E-A p.5.
(3) SCE 2025 GRC Application, p. 7., Table 1

[54] CPUC, "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), p. 26

[55] Ex. TURN-02E, p. 7, citing EIX Fourth-Quarter and Full-Year 2023 Financial Results, dated February 22, 2024, p 11, available at: https://www.edison.com/investors/events-presentations.

TURN recommends that the Commission require SCE going forward to include the "normalized"[56] revenue requirement cost of its proposals in its application. As shown in TURN's illustration, this disclosure would simply include both the proposed base revenue requirement and the revenue requirement without the cash impact of lower taxes from the depreciation timing differences. This material is already included in the utility's testimony workpapers to support its income tax showing, and as such should not be onerous to produce. The annual tax depreciation information is publicly available. Requiring such a disclosure would be an important step in clarifying the long-term cost of large capital initiatives and the impacts on affordability over time.

4.1.2 The Commission Should Find that Authorizing SCE's GRC Requested Increases Will Decrease Affordability for Customers

SCE states that the Commission has not adopted a threshold as to what level of its metrics is unaffordable.[57] It asserts that in isolation, no specific metric or analysis can determine what is affordable for *all customers*.[58] TURN agrees. However, overall SCE believes that its proposed "increase in rates and bills will not unduly impact customers' ability to pay for essential electricity service."[59] SCE's conclusions about the affordability of its request are not credible.

[56] TURN recognized that the term "normalized" has specialized meanings in tax law and regulatory accounting. Here it is used to generally mean adding back the tax effects to the revenue requirement for purposes of alternative presentation.

[57] Ex. SCE-07, Vol 4 p. 1.

[58] Ex. SCE-07, Vol 4 p. 3.

[59] Ex. SCE-07, Vol 4 p. 3.

4.1.2.1 SCE's Energy Burden & Share of Wallet Analysis Is Misleading and Inaccurate

SCE claims that if the Commission adopts SCE's clean energy investments, by the early 2030s the average SCE household can expect to see a significant decrease in total energy bills.[60] However, an examination into the assumptions behind SCE's analysis reveals that it is not only inaccurate but also misleading – the creative gymnastics engaged by SCE necessary to produce the desired result is staggering. The Commission should fully reject SCE's misleading and inaccurate analysis.

First of all, SCE's analysis does not account for the cost of purchasing an EV in order for a customer to electrify his/her transportation costs – it assumes that all customers that electrify will receive a free EV.[61] This is an absurd and misleading assumption, and the Commission should be alarmed by SCE's attempt to push its narrative that average SCE households can expect to see a significant decrease in total energy bills if its clean energy investments were adopted when it contains such an absurd assumption.

Second, SCE's analysis assumes that between 2028 and 2035, SCE's "delivery cost would continue to grow at the historical 10-year growth while the generation cost would be constant at approximately 14 cents per kWh."[62] Given that SCE's requested increase of 23% if the largest increase sought by SCE in recent GRCs, a growth at historical 10-year historical average in the future is clearly not realistic. Furthermore, the constant generation cost of 14 cents per kWh is also absurdly unrealistic. Seven years ago in 2017, SCE's generation rate was

[60] Ex. SCE-01 V01, p. 35; Ex. SCE07 V04, p. 6.

[61] 11 RT 1077:9 – 1088:10.

[62] Ex. SCE-07 V04 WP, p. 8.

7.5 cents,[63] and it is now 14.9 cents in 2024,[64] an increase of nearly 100% over seven years. This shows that an assumption of a constant generation cost of 14 cents per kWh is far-fetched.

Given the unrealistic and misleading assumptions used by SCE to produce its energy burden analysis that asserts a significant decrease in total energy bills, the Commission should disregard SCE's analysis.

4.1.2.2 Affordability Ratio (AR)

The Affordability Ratio (AR) metric quantifies the percentage of a representative household's income that would be used to pay for an essential utility service after nondiscretionary expenses such as housing and other essential utility service charges are deducted from the household's income. The higher an AR, the less affordable the utility service."[65] SCE's AR metrics show a history of steady decrease in affordability for both AR_{20} and AR_{50} (see figure below). Current AR levels have decreased by an average of more than 40% for AR_{20} and nearly 40% for AR_{50} customers, a significant decrease in affordability since 2022. Concerningly, the current and projected AR_{20} values are more than twice the 4% guideline targeted in the low-income Percent of Income Pilot program. This suggests that at least for low income AR_{20}, SCE's proposal would make already unaffordable rates less affordable.

[63] SCE AL 3659-E.

[64] SCE AL 5178-E.

[65] D.20-07-032.

SCE Historical AR Metrics[66]

Electric Climate Zone	AR20					AR50				
	2020	2022	2023	2025	% Increase	2020	2022	2023	2025	% Increase
SCE 10	5.79%	5.94%	7.5%	7.9%	36%	1.90%	1.84%	2.5%	2.6%	36%
SCE 13	6.31%	8.58%	8.4%	9.0%	42%	2.43%	2.74%	3.3%	3.5%	42%
SCE 14	8.81%	8.60%	11.8%	12.5%	41%	2.54%	2.33%	3.4%	3.6%	41%
SCE 15	10.30%	17.60%	13.1%	13.8%	34%	2.92%	4.00%	3.7%	3.9%	33%
SCE 16	6.21%	7.21%	8.3%	8.8%	41%	2.06%	2.10%	2.8%	2.9%	41%
SCE 5	8.43%	10.31%	10.9%	11.9%	41%	2.23%	2.19%	2.9%	3.1%	40%
SCE 6	5.71%	5.85%	7.5%	8.2%	43%	1.27%	1.19%	1.7%	1.8%	40%
SCE 8	6.45%	6.39%	8.6%	9.4%	45%	1.39%	1.41%	1.9%	1.9%	40%
SCE 9	6.86%	7.80%	9.1%	10.3%	50%	1.60%	1.63%	2.2%	2.3%	41%
Average	6.60%	7.21%	8.7%	9.4%	43%	1.74%	1.76%	2.3%	2.4%	39%

4.1.2.3 Hours-at-Minimum Wage (HW) Metrics

SCE characterizes the increase in Hours-at-Minimum Wage ("HW") as "modest."[67] A summary of SCE's HW calculations is shown below.

Figure 11: Summary of SCE HW Metric Calculation for Essential Service Bill[68]

SCE Climate Zone	Estimated # of Housing Units	2023						2028					
		2023 Essential Usage Average Bill	Average Bill State ($15.50/hr.)	Average Bill Los Angeles City ($16.04/hr.)	Average Bill Los Angeles Co. Malibu City Santa Monica City ($15.96/hr.)	Average Bill West Hollywood ($17.50/hr.)	Average Bill Pasadena City ($16.11/hr.)	2028 Essential Usage Average Bill	Average Bill State ($15.50/hr.)	Average Bill Los Angeles City ($16.04/hr.)	Average Bill Los Angeles Co. Malibu City Santa Monica City ($15.96/hr.)	Average Bill West Hollywood ($17.50/hr.)	Average Bill Pasadena City ($16.11/hr.)
10 hot (Sec 745)	1,347,156	$ 139.58	9.0	-	8.7	-	-	$ 160.17	10.3	-	10.0	-	-
13 hot	166,335	$ 153.45	9.9	-	-	-	-	$ 176.10	11.4	-	-	-	-
14 hot	466,812	$ 141.33	9.1	-	8.9	-	-	$ 162.18	10.5	-	10.2	-	-
15 hot	235,147	$ 201.42	13.0	-	-	-	-	$ 231.20	14.9	-	-	-	-
16 cool	150,603	$ 137.15	8.8	8.6	8.6	-	8.5	$ 157.38	10.2	9.8	9.8	-	9.8
5 warm	7,859	$ 189.26	12.2	-	-	-	-	$ 217.23	14.0	-	-	-	-
6 cool	943,130	$ 106.49	6.9	6.6	6.7	-	-	$ 122.17	7.9	7.6	7.7	-	-
8 cool	1,246,054	$ 106.60	6.9	6.6	6.7	-	-	$ 122.29	7.9	7.6	7.7	-	-
9 warm	1,160,081	$ 129.70	8.4	8.1	8.1	7.4	8.1	$ 148.83	9.6	9.3	9.3	8.5	9.2

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[66] Ex. TURN-02E, p. 24.

[67] Ex. SCE-07 Vol 4, p. 3.

[68] Ex. TURN-02E, p. 25, citing TURN DR_01.

The hours that must be worked at minimum wage to pay an essential usage electricity bill range from 7 to 8 hours or about 5% of monthly income (assuming 130 hours paid each month). By 2028, this is projected to rise to around 9 hours per month or 7% of monthly income. Based on typical usage, electricity represents roughly 12% of monthly income assuming 130 hours per month of paid labor and the state minimum wage estimate. These percentages are substantially higher than the 4% benchmark (for both gas and electric commodities) that the Commission set for its percent of income pilot program in all cases.[69] They are also higher than the 5% of gross income spent on energy (energy burden threshold) considered as a guideline in past Commission deliberations.[70] And for context, in 2022, the United Way estimates workers in Riverside must work 61 hours to afford a one bedroom apartment and worker in Los Angeles must work 88 hours,[71] before they can even begin to concern themselves with an electricity bill. Even adjusting for 2024 minimum wage of $16.00 per hour, after housing costs SCE's request would require between 16% and 25% of the remaining paid hours each month.[72] This does not consider food, transportation or other essential utility services which may also be require by the household. It is hard to imagine how households with competing cost pressures could find this level of bill affordable.

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[69] Ex. TURN-02E, p. 25.

[70] D.21-10-012, p. 41.

[71] Ex. TURN-02E, p. 25.

[72] Ex. TURN-02E, p. 26.

Figure 12: Calculation of HW Metric for 2023 Average Typical Usage Bills[73]

2023						
Hours Worked at Minimum Wage by SCE Climate Zones *(in hours except as noted)*	Typical Bill	**Avg. Bill State ($15.50/hr.)** 2	**Avg. Bill Los Angeles City ($16.04/hr.)** 2	**Avg. Bill Los Angeles Co. Malibu City Santa**	**Average Bill West Hollywood ($17.50/hr.)** 2	**Average Bill Pasadena City ($16.11/hr.)**
Maximum Minimum Wage		*$15.50*	*$16.04*	*$15.95*	*$17.50*	*$16.11*
10 hot (Sec 745)	$ 225.72	14.6	-	14.2	-	-
13 hot	$ 242.00	15.6	-	-	-	-
14 hot	$ 227.05	14.6	-	14.2	-	-
15 hot	$ 266.17	17.2	-	-	-	-
16 cool	$ 172.92	11.2	10.8	10.8	-	10.7
5 warm	$ 129.82	8.4	-	-	-	-
6 cool	$ 143.72	9.3	9.0	9.0	-	-
8 cool	$ 171.34	11.1	10.7	10.7	9.8	-
9 warm	$ 200.74	13.0	12.5	12.6	11.5	12.5
Wt. Avg. Typical Usage Bill at Various Levels of Minimum Wage	**$ 196.02**	**12.6**	**12.2**	**12.3**	**11.2**	**12.2**
Days at Minimum Wage (in days)		1.7	1.6	1.6	1.5	1.6

Figure 13: Calculation of HW for 2028 Projected Average Typical Usage Bills[74]

2028				
Hours Worked at Minimum Wage by SCE Climate Zones *(in hours except as noted)*	**Typical Bill**	**Average Bill State ($15.50/hr.)$_2$**	**Average Bill State (Escalated per CA law)$_3$**	**Higher than Average Escalated**
Maximum Minimum Wage		*$15.50*	*18.36*	*$20.00*
10 hot (Sec 745)	$ 259.10	16.7	14.1	13.0
13 hot	$ 277.80	17.9	15.1	13.9
14 hot	$ 260.63	16.8	14.2	13.0
15 hot	$ 305.56	19.7	16.6	15.3
16 cool	$ 198.46	12.8	10.8	9.9
5 warm	$ 148.97	9.6	8.1	7.4
6 cool	$ 164.92	10.6	9.0	8.2
8 cool	$ 196.64	12.7	10.7	9.8
9 warm	$ 230.42	14.9	12.5	11.5
Wt. Avg. Typical Usage Bill at Various Levels of Minimum Wage	**$ 225.00**	**14.52**	**12.25**	**11.25**
Days at Minimum Wage (in days)		1.9	1.6	1.5

[73] Ex. TURN-02E, p. 26, citing TURN DR_01.

[74] Ex. TURN-02E, p. 27, citing TURN DR_01.

4.1.3 The Record Clearly Demonstrates that SCE's "Commitment" to Affordability Is Little More Than Lip Service to the Catch Word

SCE claims that it is committed to keeping bills and rates affordable.[75] However, the Commission should find that the record clearly demonstrates that SCE's "commitment" to affordability is little more than lip service to the catch word.

Even though SCE claims that affordability was an important consideration for its GRC application,[76] SCE's CEO and President conceded that he or his team did not provide any guidelines or boundaries in terms of percentage or dollar increase to the rest of the company regarding how affordability should be considered.[77] SCE's CEO also conceded that each department could not measure the affordability of their respective GRC requested increases since the departments did not calculate affordability metrics,[78] and that the CEO or GRC team did not provide a range of increase that it wanted the individual departments or overall request to stay under.[79] Furthermore, SCE requests an increase of 23% in revenue requirement from 2024 to 2025, which results in approximately a 10% increase on the customer bills (the other bill components not addressed by this GRC could also increase further during this GRC cycle). Yet, SCE's CEO concedes that the average income for SCE customers is unlikely to grow by 10% between 2024 and 2025, [80] let alone 23%. SCE's CEO further concedes that the increases requested by this GRC would make bills less affordable for the average SCE customer.[81]

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[75] Ex. SCE-01 V01, p. 31; Ex. SCE-12, p. 5.

[76] 4 RT 365:6-14.

[77] 4 RT 365:22 – 366:18.

[78] 4 RT 367:8 – 368:7.

[79] 4 RT 371:6-21.

[80] 4 RT 379:17 – 380:2.

[81] 4 RT 380:3 – 381:1.

The above evidence clearly demonstrates that as much as SCE would like to claim that it is committed to affordability and that affordability was an important consideration in this application, the reality is that the extent of its "commitment" seems to be little more than lip service – no guidance was provided to the company on how to consider or evaluate affordability, and the lead policy witness acknowledges that the increases requested in this GRC would make bills less affordable for the average SCE customers since average incomes are likely to grow at a slower pace than the increases sought by SCE.

4.1.4 The Commission Should Weed Out Spending Requests that Provide Minimal Benefits While Enriching Shareholders and Only Approve Those Costs that SCE Has Demonstrated Are Both Necessary and Affordable for California Customers

While the Commission cannot address all issues affecting utility bill affordability, there are crucial factors under the Commission's direct control. The Commission has formally acknowledged the affordability constraint placed on the rate of growth of utility spending by the growth rate of household budgets. As the Commission stated in its decision resolving Southern California Edison's (SCE) 2018 GRC:

> Therefore, in every instance where SCE cannot establish by a preponderance of the evidence that a request is necessary to provide safe and reliable service, we deny their requests. We do so with a goal of limiting the annual increase in SCE's revenue requirements during this GRC period to, not double the growth in customer income, but rather a true alignment with no more than that growth rate. It is only by endeavoring to meet that goal, that we can begin to strive for greater affordability.[82]

[82] D.19-05-020, p. 20. (Emphasis added.)

This admonition holds equally true in this GRC. In this proceeding, the Commission will determine SCE's base revenue requirement over the next four years. As the Commission has previously recognized:

> The Commission can, and does, address issues related to affordability in other proceedings, especially those focused on rate design, low income energy efficiency, and the design of the CARE discount program. However, those cases address how to deal with the backend - how to ameliorate the impact of high rates and bills through other programs and cost allocation. They do not address the underlying cause of the high bills. The primary drivers of high customer bills, even with relatively low consumption levels compared to other states, are the high revenue requirements and associated high electric rates. It is in this rate case that the Commission can actually mitigate the root of the problem by weeding out spending requests that provide minimal benefit from a safety and reliability perspective.[83]

TURN urges the Commission to apply this fair and pragmatic view to SCE's 2025 GRC request. Because it substantially exceeds inflation and makes no effort to meet such a constraint, SCE's request will only make bills less affordable. As California emerges from the economic impacts of a global pandemic, the Commission must recognize the limitations of household budgets to absorb such high levels of growth in energy costs and only approve those costs that SCE has demonstrated are both necessary for safe and reliable service *and affordable* for California customers.

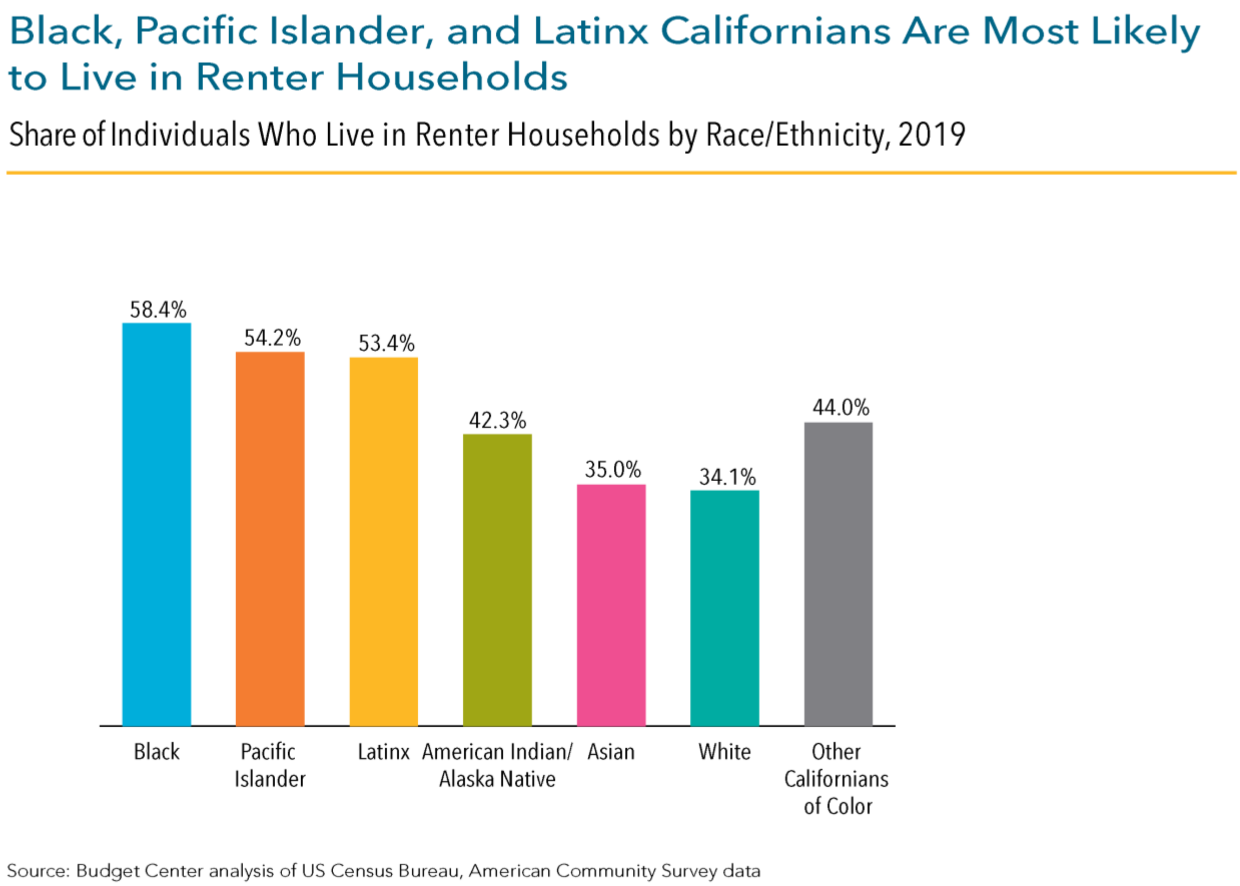
4.2 Equity Issues

4.2.1 Utility Bill Unaffordability Increases the Likelihood of Homelessness

Utility disconnections occur most often due to customer non-payment. In California renters are generally responsible for maintaining energy utilities in their homes. According to the California Association of Realtors, the template lease agreement they suggest be used

[83] D.19-05-020, pp. 18-19 (quoting TURN's opening brief).

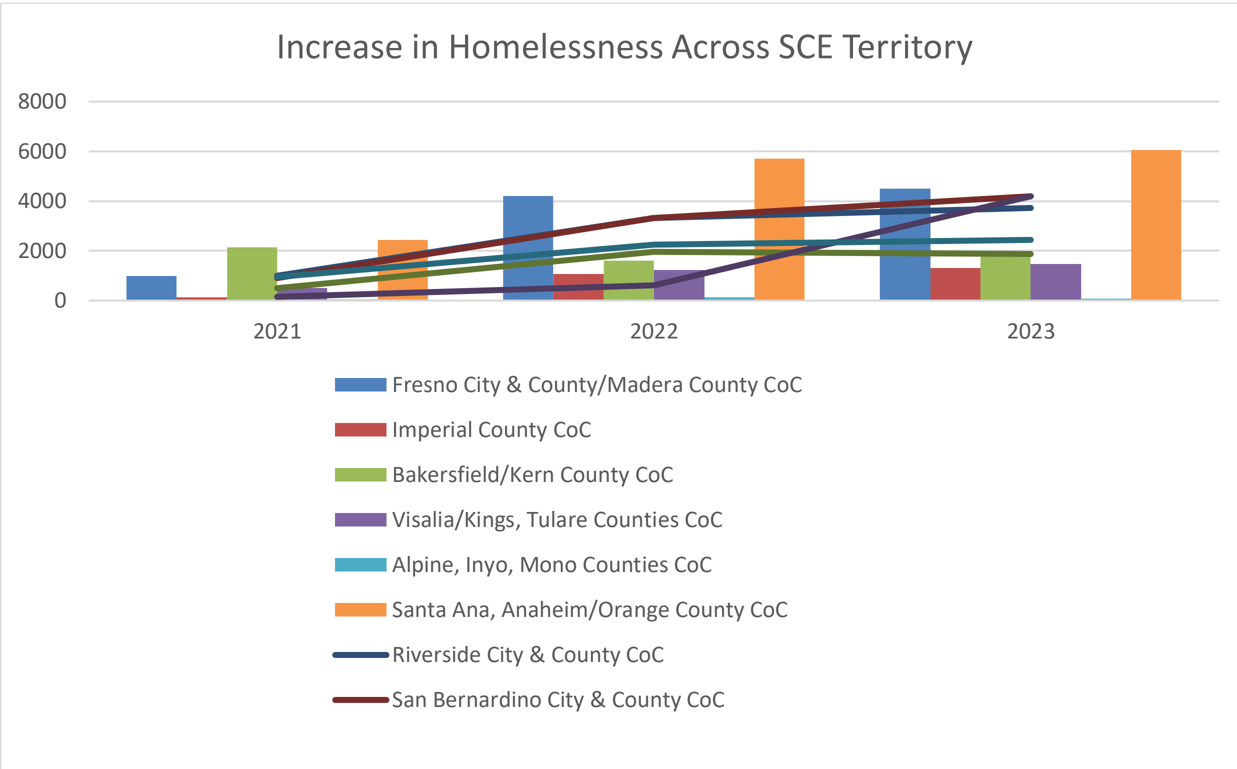
includes the statement, "RESIDENT agrees to pay for all utilities and/or services based upon occupancy of the premises except ____."[84] The form provides the option for landlords to grant exemptions for certain utilities, but the default expectation is that the tenant is responsible for maintaining active utility connection. This means that for more than 5.9 million Californians who live in rental housing, a majority of whom are people of color as shown in the figure below,[85] being disconnected from utilities could constitute a violation of their lease agreement.



[84] Ex. TURN-310.

[85] Ex. TURN-03, Figure 4, p. 7. Davalos, Monica, Sara Kimberlin, and Aureo Mequita. Issue Brief: California's 17 Million Renters Face Housing Instability and Inequity Before and After COVID-19. California Budget & Policy Center. 2021.

As SCE's rates have skyrocketed, increasing 16% since 2022[86] and far outpacing wage growth, more people than ever are facing affordability challenges that could result in disconnection, eviction, and homelessness.[87]



If rental agreements stipulate that a tenant is responsible for paying the utilities, having utilities disconnected due to customer non-payment is considered a violation of the lease agreement and grounds for eviction. According to research produced by San Diego State University, utility assistance programs that offer subsidized utility rates help people remain housed.[88] This is at least partially because when people are not able to pay their electric and gas

[86] Ex. TURN-02, p. 1.

[87] See Ex. TURN-03, pp. 3-4, FN 4-8, for details regarding increases in homeless populations in SCE's service territory based on data from County Point in Time Reports.

[88] See Exhibit TURN-311, "The Impact of Utility Assistance on Keeping People Housed," Mounah Abdel-Samad, PhD and Naader Ho, December 2020.

bills, they are vulnerable to losing their housing. As shown in the Table below, between one third and more than one half of all housing units in every county that SCE serves are renter occupied, which are disproportionately people of color.[89] Accordingly, the threat of eviction due to unaffordable energy bills is something TURN urges the Commission to consider seriously.

Table 1: SCE Territory Percent of Renter Occupied Housing by County[90]

County	**Renter Occupied Housing Units** Data from ACS 2022, Table A10060 (1 year estimate)
Tulare	41.51%
Kern	39.04%
Santa Barbara	49.24%
Ventura	34.51%
Los Angeles	54.56%
San Bernardino	37.4%
Riverside	31.44%
Orange	44.2%
Kings	42.78%
Imperial	41.29%
Mono	No data

[89] Ex. TURN-03, Figure 4, p. 7. Davalos, Monica, Sara Kimberlin, and Aureo Mequita. Issue Brief: California's 17 Million Renters Face Housing Instability and Inequity Before and After COVID-19. California Budget & Policy Center. 2021.

[90] Ex. TURN-03, p. 4, FN 9, referencing American Community Survey (2022) https://www.socialexplorer.com/3ca97b85b6/view.

Tuolumne	No data
Inyo	No data

For SCE customers who receive Section 8 housing vouchers, unaffordable energy bills not only mean potential eviction for their current residence, but also the loss of their housing voucher and expulsion from the Section 8 program.[91] Renters utilizing the Section 8 housing voucher program are required to sign a standard lease agreement, like any other renter, in addition to Section 8 specific documents with the relevant Housing Authority. The same standard lease terms apply to tenants who are using a housing voucher as to those who are not, meaning that Section 8 recipients are also in violation of their lease, and subject to eviction, if they are disconnected due to non-payment. If a Section 8 recipient is evicted by their landlord, Section 8 rules stipulate that the housing voucher will be revoked. Losing the housing voucher means that this person no longer qualifies for the rental assistance necessary to afford housing, making it extremely difficult to secure new housing. In short, utility disconnections directly contribute to evictions and homelessness for all renters and may result in chronic homelessness for California's most vulnerable renters.

In all three Public Participation Hearings held in this proceeding, SCE customers came forward to share their desperate concerns about the likelihood that they, or their fellow community members, could become homeless due to utility disconnection and eviction.

[91] See Exhibit TURN-312, "Section 8 and Subsidized Housing Part 03: Evictions and Terminations, California Courts Section 8 & Subsidized Housing" Webpage, available at https://www.courts.ca.gov/section8.htm.

Table 2: Public Participation Hearing Comments Regarding Concerns of Homelessness

Date	Location of PPH	Name and Place of Residence	Page number, line number	Comment
3/5/24	Virtual	Annah Laux-Minjnares, Newhall, CA	Page 68, Lines11-14	It's not a joke when people are talking about being homeless or having to eat cat food or dog food because you can't afford the electricity in the summer months because it's so overwhelmingly hot.
3/5/24	Virtual	Gigi Jackson, Orange County, CA	Page 52, Lines 17-21	We're concerned about our homeless populations and at this pace, if those of us who are on fixed incomes continue at this pace, we're not going to be able to continue in our house or the apartments that we live in.
3/7/34	Docket card	Jacob Diaz, Long Beach	Online docket card. Page 44 of downloaded PDF	To allow rate increases for customers during a time of massive inflation, housing crisis, homeless crisis, we believe the commission would not be representing the will, interests and safety of Californians and energy consumers.
3/9/24	Docket card	Paul Calabrese, Victorville	Online docket card. Page 42 of downloaded PDF	Please stop increasing rates. I can barely afford rent/mortgage as it is. Now you want to increase rates for electricity. California needs to realize what it's doing to its people. You are going to have more homeless than ever before why can't you guys use your head?
3/20/24	Virtual	Linda Stevens, Long Beach, CA	Page 118, Lines 13-19	Last month, my electric bill was the highest it's ever been, $456. This month, March, my bill is $350. So, just to struggle to pay that, that's like $800 in two months. Someone who's retired, on a fixed income, and without family help, I wouldn't be able to pay it. So, we wonder why a lot of people end up homeless, can't pay their bills.

4/10/24	Long Beach	Angie Reyes-English, City Council member in City of Hawthorne	Page 267, Lines 1-11	Keep in mind that California has 180,000 homeless individuals today. It is up six percent from 2023. I used to be homeless living in a car. That's fact. You've got COVID you just ended. You've got people that are in the rears. Come February 1, they were all due, all rents. People can't afford that. They're not going to afford that. They will never afford that. Therefore, you are going to have people pushed out into the streets again. Homelessness, again, will rise from six percent even higher.
4/10/24	Long Beach	Andrew Mandujano, Development Manager with Long Beach Residents Empowered	Page 285, Lines 12-20; Page 286, Lines 2-6	We know that the housing crisis is severe in Southern California, oftentimes, depending on terms of tenant's leases, the inability to afford utility bills can lead to an eviction as this continuing essential service may violate potential agreements. This is specifically concerning given the 2023 point-in-time homeless count found that 60 percent of all homeless individuals in Long Beach become homeless because of an eviction. So, this proposed rate increase doesn't just directly cause an increase in monthly bills on top of housing-cost-burdened individuals. They mainly directly cause homelessness and disastrous health impacts for our aging population.
4/10/24	Long Beach	Martha Pineda, Alhambra	Page 309, Lines 4-10 and 16-22	If you proceed to move forward with this rate increase, what you're saying or what Edison and everyone included will be saying is that they don't really care about the livelihood of these communities. Raising the utility rate will lead to higher default rates overall and an increased risk of homelessness. So, we know very well, you know, how severe the housing crisis is, and it will continue to get worse, if we treat housing and utilities as a luxury, instead of a human right. This rent [*rate*] increase would lead people to their

				inability to afford utility bills, which would lead to an eviction, which would lead to homelessness.
4/10/24	Long Beach	Melodie Cuevas, Long Beach	Page 310, Lines 10-22	In a already difficult and grueling economy, a $26 increase per month, or $312 annually, would hurt many families. Working in many low-income communities, many families cannot even afford the cost of living at the moment, going into severe debt just by simply living. Although $26 may not seem like much, for many families, it is choosing between food and electricity. It is a very scary position to be in. I've worked with communities who have severe utility debt, and have advocated for utility efforts for many people who have either been evicted or are in jeopardy of being so.
6/6/24	Docket card	Gayle Nollau, Crestline	Online docket card. Page 87 of downloaded PDF	When does the greed stop. Between your company and the gas company more and more people are becoming homless. I get a rate proposal notice in almost every bill. This has to stop. Enough is enough. You need to hire more professional budget analysts or let anotuher company take over that's more efficient at running electric business that can lower rates. You are constantly sending out notifcations requesting an increase in rates and I'm tired of it and can't afford it.

4.2.2 Frontline Communities: Known Harms and Unknown Benefits of SCE's Transportation Electrification Grid Readiness Plan Forecast

The Commission should reject the Transportation Electrification Grid Readiness (TEGR) supplemental portion of SCE's load growth forecast that SCE claims is required to support medium and heavy duty (MDHD) fleet electrification in Exhibit SCE-07, Vol. 4. TURN's primary opposition to the TEGR plan forecast, as discussed in greater detail below in Section

11.1, is that SCE has not met its burden to establish this forecasted level of spending is necessary and reasonable. Additionally, TURN highlights the inherent inequity in these costs here.

SCE acknowledges that the "TEGR request is primarily driven by MDHD electrification, not residential ownership of LD EVs."[92] At its core, these TEGR load growth projects benefit those private companies the distribution infrastructure upgrades are being made on behalf of, while harming families who already struggle to pay their electric utility bills. These companies will benefit from a savings on vehicle fuel and maintenance costs, as supported by SCE's own witness, R. Thomas,[93] and can boost their public image as companies invested in environmental responsibility, while residential ratepayers will receive increased monthly bills.

TURN believes the transition to transportation electrification needs to be done equitably and not at the expense of the most vulnerable ratepayers. The argument in Exhibit SCE-13, Vol. 7 that increased electric demand will eventually result in downward pressure on rates,[94] assumes that ratepayers will be able to weather the near-term financial storm. Unfortunately, many customers already struggle to pay their utility bills, and cannot afford any more rate increases. Additionally, higher bills deter people from consuming additional electricity, and in turn, deter them from switching to plug-in electric vehicles. This means the demand for electricity may not increase as quickly as SCE claims, thus pushing back the timeline for when this "downward pressure" will occur. In the meantime, people are left to struggle to avoid disconnection in the face of unaffordable bills. This affordability crisis makes it vitally important that every dollar of ratepayer spending go toward benefitting the public good.

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[92] Ex. SCE-13, V07, p. 34.

[93] Hearing Transcript, Volume 11, May 15, 2024, p. 1067: line numbers 2-17 (SCE/ Thomas).

[94] Ex. SCE-13, V07, p. 34.

Although SCE and NRDC claim that vulnerable front-line communities – communities near freeways, refineries, and other pollution sources – will receive air quality benefits from the electrification enabled by the proposed load growth projects, there has been no evidence of the specific benefits of SCE's TEGR load growth projects presented in this case to substantiate that claim. When TURN asked about this issue, SCE responded to a data request by citing to a 2022 study, "Quantifying the Air Quality Impacts of Decarb and Distributed Energy Programs in California,"[95] which models the potential air quality benefits of complete transportation electrification, across all vehicle classifications, statewide.[96] While the study does offer a breakout of impacts specific to the South Coast Air Basin (SoCAB), the model used only considers "complete removal of emissions from each sector."[97] This research does not offer any insight into the incremental impacts on air quality from projects like SCE's, which only support electrification of a small fraction of the vehicles on the road, not complete removal of emissions from the transportation sector.

SCE's TEGR investments will only produce air quality benefits if forecast vehicle populations emerge to make use of SCE's infrastructure. As discussed in Section 11.1, the forecasting methodology underlying the TEGR significantly overestimates MDHD EV population growth. Given the numerous other sources of pollution in SCE territory,[98] including

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[95] Ex. TURN-309: Quantifying the Air Quality Impacts of Decarbonization and Distributed Energy Programs in California, Energy and Environmental Economics, Inc. & Advanced Power and Energy Program (funded by the CPUC), 2022.

[96] Ex. TURN-309, Quantifying the Air Quality Impacts of Decarb and Distributed Energy Programs in California, EEEI & APEP (funded by the CPUC), 2022, p. 5.

[97] Ex. TURN-309, Quantifying the Air Quality Impacts of Decarb and Distributed Energy Programs in California, EEEI & APEP (funded by the CPUC), 2022, p. 24.

[98] See Ex. TURN-03, Table 1, p. 12-13.

oil refineries, meat rendering plants, and other industries, it stands to reason that the electrification of only a fraction of on-road vehicles will create, at most, a very small improvement to air quality. The marginal degree of air quality improvement the TEGR load growth projects might provide has not been quantified and should not be assumed to be significant enough to justify the harms to vulnerable ratepayers resulting from the associated rate increase.

While the potential benefits of SCE's TEGR load growth projects are unknown, the harms from unaffordable bills are very well known. High energy bills often force people to sacrifice buying food and medicine, or using air conditioning during extreme heat events, so they can afford to pay their monthly bill. That is an untenable, and potentially unhealthy, decision that SCE ratepayers are forced into making. Customers who are unable to pay their bills face disconnection, accumulated debt, and potentially eviction and homelessness.[99] SCE's proposal is an example of spending that benefits select private corporations but harms residential ratepayers.

Given the extensive harms discussed above, TURN urges the Commission to minimize to reject all unnecessary rate increases. In the context of SCE's Load Growth forecast, this measn rejecting the inflated TEGR load growth capital expenditures forecast as discussed in Section 11.1 below. The Commission must be prudent in the evaluation of residential bill impacts relative to residential benefits. Prioritizing equity in utility spending is a critical component to combatting the state's homeless crisis and protecting the wellbeing of low-income customers, as well as Black, Indigenous and other People of Color (BIPOC) customers who have been historically marginalized.

[99] Ex. TURN-03, pp. 3-5.

5. RISK-INFORMED STRATEGY AND BUSINESS PLAN

5.1 Climate Change Policy

5.2 Environmental And Social Justice Goals

5.3 Quantitative Risk Modeling

This is the third GRC in which the utility is required to present the results of its quantitative risk modeling pursuant to the S-MAP Settlement adopted in D.18-12-014.[100] In order to assess the current state of risk on the system, the S-MAP framework requires the utility to calculate baseline risk scores for portions of its system with homogenous risk profiles, referred to as tranches. To assist in prioritizing the utility's proposed spending of ratepayer funds, it further requires the utility to calculate risk spend efficiency (RSE) values – risk reduction divided by cost –f or each risk mitigation program, both in the aggregate (i.e., for the entire proposed program) and broken down by tranche.

Like its predecessors in this cycle of GRCs, PG&E and the Sempra Utilities, SCE attempts to downplay the usefulness of the results of this required quantitative risk analysis in CPUC decision-making. SCE states that RSEs should not be the only factor on which the CPUC should base its funding decisions[101] -- a statement that TURN does not dispute -- but SCE goes further and incorrectly contends that the quantitative analysis required by the CPUC should be given a limited role in decision-making because, among other things, it does not account for the company's expertise and judgment.[102] In other words, SCE would prefer that the CPUC rely

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[100] D.22-12-027 revised the MAVF framework adopted in D.18-12-014 and directed utilities to transition to a new Cost-Benefit Approach in their next RAMP/GRC cycle. Accordingly, the S-MAP framework adopted in the Settlement approved in D.18-12-014 applies to SCE in this case.

[101] Ex. SCE-01, Vol. 2, p. 18.

[102] Ex. SCE-15, Vol. 5, pp. 14-15. TURN rebuts this argument with respect to SCE's grid hardening proposal in Section 15.2.4.4 below.

more on the utility's qualitative arguments, rather than the rigorous output of the S-MAP framework, which takes advantage of the best available data ***and*** the utility's expertise and judgment.

TURN disagrees with utility efforts to discourage use of the S-MAP quantitative analysis to promote the best use of ratepayer funds. Quantitative risk analysis is a vital tool to ensure finite ratepayer funding is used reasonably and cost-effectively. TURN agrees with D.21-08-036 that "RSE calculations are *critical* for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds."[103]

The value and importance of the quantitative information furnished via the S-MAP framework was an issue in controversy in this case that influenced the parties' positions regarding certain wildfire grid hardening and vegetation management programs. With respect to grid hardening, rather than rely on the results of its S-MAP analysis, SCE's undergrounding proposal is predicated on its ***qualitative*** designation of "Severe Risk Areas," which conflicts with the results of the S-MAP framework and amounts to an attempted end-run around the CPUC's required quantitative analysis.[104] In addition, as discussed in Section 15.2.2, RSE analysis shows that covered conductor is far more cost-effective than undergrounding. This important information, along with considerable additional analysis presented by TURN, supports a more modest and targeted undergrounding program than SCE has proposed and a continued reliance on covered conductor as the centerpiece of SCE's grid hardening efforts in high fire threat

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[103] D.21-08-036, p. 38, quoting Resolution WSD-002 (June 11, 2020), p. 20 (emphasis added).

[104] *See* Section 15.2.4 below.

districts (HFTD).[105] Moreover, SCE's quantitative S-MAP analysis shows that, following SCE's extensive and successful deployment of covered conductor in the riskiest locations, wildfire risk has been significantly reduced and is highly concentrated, further supporting a highly targeted undergrounding program.[106]

With respect to vegetation management, as discussed in Section 14.3, the RSE and B/C Ratio information in the record show that two programs, expanded line clearing[107] and the Hazard Tree Management Program[108] are not cost-effective and should not be funded by ratepayers.

Before responding to SCE's attempt to minimize the value of quantitative risk modeling under the S-MAP framework, TURN provides two background sections regarding, first, the definition and purpose of RSEs (Section 5.3.1) and second, the history of how quantitative risk analysis and RSEs came to be a requirement in GRCs (Section 5.3.2). In Section 5.3.3, we discuss the supplemental information added by TURN's testimony to improve the record regarding the results of SCE's quantitative risk analysis. Finally, in Section 5.3.4, we discuss why SCE's undervaluing of the S-MAP quantitative risk analysis is contrary to Commission precedent and sound policy.

5.3.1 Overview of RSEs and Risk Scores

RSE is a way to quantify the cost-effectiveness of a risk mitigation activity. Specifically, RSE is the estimated risk reduction from an activity divided by its estimated cost,

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[105] TURN presents its full arguments for its grid hardening proposal in Section 15.2 below.

[106] *See* Sections 15.2.3 and 15.2.6 below.

[107] *See* Section 14.1.3 below.

[108] *See* Section 14.3 below.

where both the numerator and the denominator are expressed in present value terms.[109] RSEs enable a comparison of the cost-effectiveness of various proposed risk reduction activities, which allows those activities to be prioritized based on cost-effectiveness.[110] In addition, as will be discussed in Section 5.3.3 below, RSEs calculated under the S-MAP Settlement can be expressed as Benefit-Cost (B/C) Ratios in which the risk reduction value in the numerator is expressed in terms of dollars. B/C Ratios provide additional information -- whether the monetary value of risk reduction benefits exceed the costs – that enables assessment of the cost-effectiveness of a mitigation on a stand-alone basis.[111] However, just because a proposal is "cost-effective" does not necessarily mean it should be adopted by the Commission – more cost-effective solutions (*i.e.,* with higher RSEs and B/C ratios) may be available or reductions in funding may be warranted if the proposal is not consistent with affordable rates.[112]

In the quantitative risk modeling mandated by the S-MAP Settlement, risk is calculated by a simple equation: Likelihood of the Risk Event (LoRE) times the Consequences of the Risk Event (CoRE)., *i.e*., LoRE × CoRE.[113] The S-MAP Settlement requires SCE's LoRE and CoRE estimates to be based on data, and where necessary, to be supplemented by subject matter expertise.[114]

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[109] D.18-12-014 (adopting S-MAP Settlement), p. A-13, Row 25.

[110] Ex. TURN-04 (Borden), p. 3.

[111] Ex. TURN-04, p. 3.

[112] *Id.,* p. 15.

[113] S-MAP Settlement, p. A-11, Row 13.

[114] S-MAP Settlement, p. A-18, Row 31. *See also* Section 15.2.4.4 regarding the role of utility subject matter expertise and judgment in the S-MAP framework.

To calculate the risk reduction from a proposed mitigation activity, one compares the level of risk, or risk score, prior to applying the mitigation to the risk score after the mitigation is implemented. The difference between the *pre-mitigation risk score* (calculated as pre-mitigation LoRE times CoRE) and the *post-mitigation risk score* (post-mitigation LoRE times CoRE) is the risk reduction, the numerator in the RSE calculation.[115]

The S-MAP Settlement requires risk reductions and RSEs to be calculated at the *tranche* level to give a more granular view of how mitigations will reduce risk.[116] Row 14 of the Settlement explains how tranches are to be determined and requires that, for each risk, assets be grouped such that each tranche has a homogenous risk profile (*i.e.*, the same LoRE and CoRE).[117] Appropriately granular tranches are important for comparing RSEs within a single proposed program because, within a group of assets addressed by a program, there can be a variety of factors affecting the level of risk. Tranche-level RSEs enable better targeting of ratepayer dollars to the most cost-effective activities.[118]

The quantitative methodology mandated by the S-MAP Settlement is thus a rigorous and methodical approach to marshalling the utility's data and expertise in order to quantify the current state of risk on the utility's system and the cost effectiveness of the utility's proposed risk reduction activities.

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[115] S-MAP Settlement, p. A-12, Rows 19, 22, and 23.

[116] S-MAP Settlement, p. A-11, Row 14.

[117] *Id*.

[118] Ex. TURN-04, pp. 17-18.

5.3.2 The Commission Developed Quantitative Risk Analysis as a Useful Tool to Prioritize Risk Reduction Spending

Beginning a decade ago, the Commission has devoted considerable time and effort to developing a quantitative methodology for prioritizing utility spending based on cost-effectiveness.[119] In D.14-12-025, the CPUC established the RAMP as a precursor to GRCs and specified that utility RAMP submissions should present "a prioritization of risk mitigation alternatives, in light of estimated mitigation costs to risk mitigation benefits (Risk Mitigated to Cost Ratio),"[120] which is another way of describing what has come be known as RSE. In further pursuit of the goal of prioritizing utility programs based on cost-effectiveness, D.16-08-018 adopted the Multi-Attribute Value Function (MAVF) approach for quantifying risk reduction, noting that the MAVF model "enables the computation of cost-effectiveness for different mitigations."[121]

The Commission's years-long efforts to adopt a methodology for quantifying the cost effectiveness of utility mitigation proposals came to fruition in D.18-12-014, which adopted the S-MAP Settlement. The large utilities and intervenors agreed in that Settlement to the detailed methodology for calculating RSE, described in the previous section, as well as the requirement that utility GRCs provide a ranking of mitigations by RSE.[122] In adopting that Settlement and making it mandatory for the utility calculation of RSEs, the Commission stated that one of the goals achieved by the Settlement was to "use risk reduction per dollar spent to prioritize

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[119] Order Instituting Investigation (OIR) 13-11-006, p. 1, identified as a goal of the proceeding to "better equip decision makers with the necessary information to ensure that we prioritize safety while continuing our long-standing mandate to ensure that adopted rates are just and reasonable."

[120] D.14-12-025, p. 32. The decision states on page 41 that it adopts the elements of the "Refined Straw Proposal" listed on page 32, which include the material quoted in the text.

[121] D.16-08-018, p. 115.

[122] S-MAP Settlement, p. A-14, Row 26.

projects."[123] The Commission further explained that the adopted Settlement "demonstrates success" toward a more rigorous, quantitative method of risk assessment and risk prioritization and toward "providing information required to better understand the cost effectiveness of proposed mitigations."[124]

Thus, the S-MAP Settlement's RSE methodology adopted in D.18-12-014 represents the Commission's success in its decade-long effort to fill a significant void in its decision-making record in GRCs – RSE information that enables the Commission to prioritize risk reduction proposals based on a quantitative measure of cost-effectiveness. The Commission's continued commitment to this effort is shown by the modifications to the S-MAP framework ordered in D.22-12-027, designed to enhance the usefulness of the cost-effectiveness information. Those modifications require risk reduction values to be calculated in dollars, enabling direct computation of cost-benefit ratios for each proposed mitigation.[125]

5.3.3 TURN's Testimony Supplements the RSE Information Presented by SCE and Presents the SCE and TURN Information in a Useful Format

As required by D.18-12-014, SCE presented RSE results for most risk reduction programs it proposes in this case and a ranking of those programs by RSE.[126] TURN supplemented SCE's RSE information in two ways.

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[123] D.18-12-014, pp. 12, 14 (item 8, "*" indicates goal was achieved by the Settlement).

[124] D.18-12-014, p. 44.

[125] D.22-12-027, pp. 25-26. SCE was not required to implement the enhancements ordered in D.22-12-027 in this GRC, but will be required to do so in its next RAMP submission. *Id.,* p. 63 (Ordering Paragraph 2).

[126] Ex. SCE-01, Vol. 2, p. 22.

First, TURN calculated alternative RSEs using different discount rate assumptions than those that underpin SCE's RSEs. TURN's expert, Eric Borden, explained the importance of discount rates to the RSE results:

> The choice of the discount rate used to develop the present value of benefits and costs is important because the benefits and costs of a risk mitigation can accrue over many years, and at times, the benefits and costs accrue over different timescales relative to one another. An RSE is therefore sensitive to the discount rates used for benefits (risk reduction, in the numerator) and costs (dollars, in the denominator).[127]

SCE used a 3 percent discount rate for benefits (risk reduction, the numerator of the RSE calculation), and a weighted average cost of capital (WACC) of 7.44 percent for costs (dollars, the denominator of the RSE calculation.[128]

For reasons explained in Mr. Borden's testimony, TURN believes that it would be more reasonable to use a uniform discount rate in both the numerator and denominator and that this uniform discount rate should be the WACC.[129] TURN therefore recalculated SCE's RSEs in this way and included those alternative values in the RSE tables attached to TURN's testimony.[130] TURN's adjustment decreased SCE's RSE numerators and therefore the RSEs, the magnitude of the decrease dependent on the number of years of expected benefits for the mitigation in question. The RSE reductions ranged from 6 percent to 47 percent.[131]

TURN's presentation of alternative values to show the sensitivity of RSEs to different discount rates proved to be consistent with D.24-05-064, even though that decision was issued

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[127] Ex. TURN-4, p. 4.

[128] *Id.*, p. 7.

[129] *Id.*, pp. 7-12.

[130] Ex. TURN-4, p. 12.

[131] *Id.*, pp. 12-13.

after all testimony was submitted in this case. D.24-05-064 directed the utilities to present three discount rate scenarios for their future CBR calculations, with one of the scenarios being the same as the alternative approach TURN presented in this case.[132]

TURN emphasizes that making this one adjustment to SCE's RSEs does not mean that TURN believes the revised RSEs are without flaws. For example, in the RAMP, TURN also expressed concern about the excessive implied value of a statistical life (VSL) on which SCE's risk scores and RSEs are based, which inflates SCE's RSEs.[133] SCE did not fix this problem in its GRC risk modeling. Accordingly, while TURN believes that the SCE and TURN RSE values can be highly useful to inform CPUC decision-making,[134] the Commission should recognize that most of SCE's RSEs are unduly inflated.

Second, TURN converted SCE's RSE values to Benefit/Cost (B/C) Ratios. TURN's testimony explained that, based on SCE's MAVF parameters, this conversion is accomplished by dividing SCE's RSEs by 50.[135] A B/C Ratio below 1.0 indicates that costs exceed benefits and the mitigation is not cost-effective. As discussed in Section 14.3, SCE's results show this to be the case for two vegetation management programs. TURN cautions that a B/C Ratio above 1.0

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[132] D.24-05-064 (decision in Phase 3 of the Risk-Based Decision-Making Framework docket, R.20-07-013), pp. 102-103.

[133] SPD Staff Evaluation Report on SCE's 2022 RAMP, A.22-05-013, Nov. 10, 2022, Attachment 3 (TURN Comments), pp. 10-14 (hereinafter "SPD RAMP Evaluation). The SPD RAMP Evaluation and the party comments were made a part of the record of this case by ALJ ruling. Tr. Vol. 10, p. 996:20 – p. 997:3. The CPUC agreed that utilities RSEs were based on excessive implied SVLs in D.22-12-027, and ordered a correction to this flaw to be applied in the new Cost-Benefit Approach. D.22-12-027, pp. 35-36.

[134] Ex. TURN-4, p. 5.

[135] Ex. TURN-4, p. 14.

does not necessarily mean that an activity should be approved.[136] As discussed above, SCE's (and TURN's discount rate-adjusted) RSEs may be significantly inflated, which likewise inflates the B/C Ratios. In addition, where a competing alternative has a higher RSE and B/C Ratio, as in the case of covered conductor compared to undergrounding, the B/C ratio should not be dispositive.[137]

TURN presented SCE's RSE results, TURN's alternative RSEs based on its recommended discount rate approach, and the B/C Ratio equivalents for both sets of RSEs in tables attached to TURN's testimony and in workpapers.[138] Both tables include RSEs and B/C Ratios for the aggregated program proposed by SCE, as well as for each tranche identified by SCE.[139] The first table[140] presents this information organized by risk category, and the second table[141] sorts the information from highest to lowest RSEs, using SCE's RSE values. The lower ranked discretionary activities proposed by SCE are candidates for reduced or eliminated funding, as SCE's data shows they provide low risk reduction benefit per ratepayer dollar.[142]

5.3.4 SCE Undervalues Quantitative Risk Analysis

As noted in the introduction to this section, SCE attempts to downplay the usefulness of the S-MAP quantitative analysis, viewing those results as just one factor among many other

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[136] Ex. TURN-4, p. 1

[137] *Id.*

[138] Ex. TURN-4, p. 18 and Appendix A, Tables 2 and 3. TURN provides its Excel workpapers supporting these tables and presenting different views of the information in Ex. TURN-4-Atch1.

[139] Ex. TURN-4, p. 18. TURN's use of SCE's tranches does not mean that TURN agrees that SCE's tranches are correctly delineated and sufficiently granular. *Id.,* p. 18.

[140] Table 2 in Ex. TURN-4, App. A.

[141] Table 3 in Ex. TURN-4, App. A.

[142] Ex. TURN-4, p. 4.

qualitative considerations that must be taken into consideration.[143] While, of course, Commission decisions should take into account all relevant considerations, the CPUC should reject the view that RSE results are just another data point. SCE's position is at odds with the Commission's decade-long effort – and continuing efforts in R.20-07-013 -- to develop the S-MAP quantitative risk methodology; the Commission would not commit so much time and effort to the initiative unless it were meant to make a transformative improvement to its decision-making tools.

In addition, SCE's reliance on *qualitative* analysis to justify its risk reduction proposals is exactly what the Commission has been trying to improve upon. Absent risk scores and RSEs, the record would be limited to program after program in which the utility's argument boils down to an assertion that the proposed activity is necessary or important for safety. Such qualitative prose discussions offer no means for the parties or the CPUC to compare how much risk the various proposals would reduce and to assess which proposals are more important or cost-effective than others. Moreover, the risk scores and RSEs that SCE seeks to downplay are, in accordance with the S-MAP Settlement, the tip of a deep and extensive pyramid of analysis – performed by SCE itself -- of all of the key factors in deciding whether a proposed risk reduction program should be funded.[144]

For any discretionary program designed to reduce risk, the ultimate questions the CPUC must decide concern whether the program is needed, whether it is a worthwhile use of ratepayer funds, and, if it is a worthwhile program, whether the utility's proposed scope for the program is

[143] *E.g.*, Ex. SCE-01, Vol. 2, p. 17; Ex. SCE-15, Vol. 15, Part 2, pp. 10, 14.

[144] *See* Section 15.2.4.4.

reasonable and affordable in combination with other funding decisions. Central to all of these issues are the very questions that are addressed by the S-MAP quantitative analysis, including:

- What is the risk event the program would address?
- What is the baseline level of the risk? In that baseline risk, what is the breakdown between likelihood and consequences of the risk event, *e.g.*, is it a high consequence–low likelihood risk or a low consequence-high likelihood risk?
- What are the drivers (causes) of the risk event?
- How effective is the proposed program at mitigating the risk drivers or otherwise reducing the risk?
- How much would the proposed program reduce the baseline risk and how does that risk reduction compare to the cost of the program? Is the program providing good risk reduction value for the money it would cost?
- How does the proposed program compare to alternative programs regarding risk reduction and cost?
- How much would the risk reduction benefit vary based on the portion of the system (i.e., tranche) that is being addressed? Would a more targeted program, or combination of alternatives, be a more efficient use of ratepayer funds?

The S-MAP Settlement's RSE methodology requires the utility to do a comprehensive analysis of all of these key issues. The resulting values should thus be highly informative in the CPUC's decision-making process.[145]

[145] SCE also takes its argument too far in contending that the S-MAP framework ***precludes*** it from basing its proposals solely on quantitative risk analysis and RSEs. (Ex. SCE-15, Vol. 5, Part 2, p. 19.) This contention is based on a misreading of D.22-12-027. Rather than stating that numerous other qualitative and quantitative factors *must* be taken into account, D.22-12-027 makes the correct and much more limited point that RSEs and B-C ratios "need not" serve as the sole determinants of risk mitigations to fund. (D.22-12-027, p. 26.) This statement is fully consistent with Row 26 of the D.18-12-014 Settlement which provides that utilities are "not bound" to select mitigations based "solely" on RSE rankings, but requires utilities that deviate from RSE rankings to "explain whether and how" any non-RSE factors affected the utility's mitigation selections. D.22-12-027 states that it retains the language and direction of Row 26 (*id.*), which makes clear that RSE analysis should serve a key role in the selection and justification of mitigations, consistent with the CPUC's longstanding and continuing efforts to use quantitative risk analysis to prioritize spending.

6. DISTRIBUTION GRID

6.1 Infrastructure Replacement

SCE describes Distribution Infrastructure Replacement (DIR) as a continuous and necessary process involving the renewal and upgrading of fundamental components of the electricity distribution system, such as poles, transformers, cable and conductors, based on the probability and consequences of in-service failures.[146] SCE further notes that where in-service failures have minimal consequences, a run-to-failure strategy may be the preferred approach.[147] The Commission needs to balance, on the one hand, the need for such DIR and the safety and reliability benefits that it may reasonably expect to be achieved through well-supported programs and, on the other, the extraordinary cost levels that can attach to such programs. Ultimately, the determination of the necessity of the proposed investments rests largely on the modeling used to determine the probability of failures and the safety and reliability consequences in cases where no replacement occurs and potential failures ensue.

- **Safety and Reliability Impacts of Pre-2018 DIR Spending Cuts May Be Overstated.**

It is essential that the Commission closely and carefully review SCE's proposals, and only authorize funding to the extent the utility has established that its proposal relies on compelling evidence that is sufficiently transparent. The Commission must also keep in mind that SCE unilaterally chose to significantly scale back its DIR activities and spending levels in recent years, particularly in the 2021-2024 period. After spending approximately $500 million per year during the 2014-2018 period, SCE's recorded DIR spending for 2021 and 2022 were in

[146] Ex. TURN-5-E, p. 35, citing Ex. SCE-02, Vol. 1, Pt. 2, p. 4; Ex. SCE-02, Vol. 1, Part 2, p. 5.

[147] Ex. SCE-02, Vol. 1, Part 2, pp. 5, lines 22,23

the $200 million per year range, with similar amounts forecasted for 2023 and 2024. For the 2025 test year and the remainder of the upcoming GRC period, SCE forecasts total spending in the $700-$800 million range.[148] Importantly, the record evidence demonstrates that SCE's customers did not experience significant declines in the utility's reliability or safety performance during the years of relatively lower spending. The linear fit of System Average Interruption Duration Index (SAIDI) figures reveal a near straight-line trend for the 2013-2022 period, whether viewed on a distribution-only or system-wide basis.[149] Similarly, the number of "wire-down" events was relatively stable during the 2018-2022 period, and the serious injuries and fatalities (SIFs) associated with such events was lower in 2018-2022 (two injuries total) as compared to 2013-2017 (ten injuries and five fatalities).[150]

- **SCE's Data and Modeling Lack Compelling Evidence to Justify the Utility's Very Substantial Proposed Increase in DIR Spending.**

TURN's recommendations rely on three general arguments, in addition to the program-specific issues raised in the sections that follow. First, the Commission needs to recognize that a transmission level fault may cause poorer distribution-level reliability as measured by the SAIDI and SAIFI metrics.[151] Secondly, SCE's approach to maintaining a steady-state replacement rate is based solely on a theoretical model lacking detailed, asset-specific historical data to substantiate an evidence-informed rate or frequency of replacement.[152] Third, while TURN

[148] Ex. TURN-05-E, p. 36, Figure 14

[149] *Id.*, p. 38, Figure 17 2013-2022 SAIDI trend from SCE's 2022 Annual Reliability Report. The SAIDI trend for SCE's transmission operations slopes downwards, for reasons unrelated to SCE's distribution infrastructure.

[150] Ex. SCE-02, Vol. 1, Part 2, pp. 84 (Figure II-41) and 86 (Table II-21).

[151] Ex. TURN-05-E, pp. 38-39.

[152] *Id.*, pp. 39-40. It is worth noting that in SCE's test year 2021 GRC, the Commission noted that the utility there argued "that attempting to calculate a steady-state replacement rate for [infrastructure

supports SCE's use of advanced machine learning (ML) models, it is essential that these models operate with transparency and undergo independent peer reviews to ensure their methodologies are both understandable and verifiable.[153] Given the magnitude of the utility's proposed infrastructure replacement spending ($3.6 billion in this GRC period alone) and modeling of safety and reliability implications, it is essential that SCE establish the effectiveness of its selected models, and provide stakeholders and, ultimately, the Commission with the means to understand and independently verify the models.[154]

- **Investigate Breadth of Unit Cost Calculation Issues**

In addition, there is an overarching unit cost issue that may warrant further inquiry. When TURN identified the potential for unit cost estimates being higher than they should be due to a double escalation build into their calculation, SCE investigated and confirmed such issues with unit cost estimates in the "Circuit Breaker Replacement" and "Substation Transformer Bank Replacement" programs. TURN submits that further scrutiny is needed for the "Relays, Protection and Control Replacements Program" (TY 2025 forecast of $72.3 million) and "Substation Rebuilds Program" (TY 2025 forecast of $91.1 million).

6.1.1 Overhead Conductor Program

SCE proposes a massive expansion of its Overhead Conductor program, including ultimately targeting approximately 30,000 of non-High Fire Risk Area (HFRA) circuit miles out

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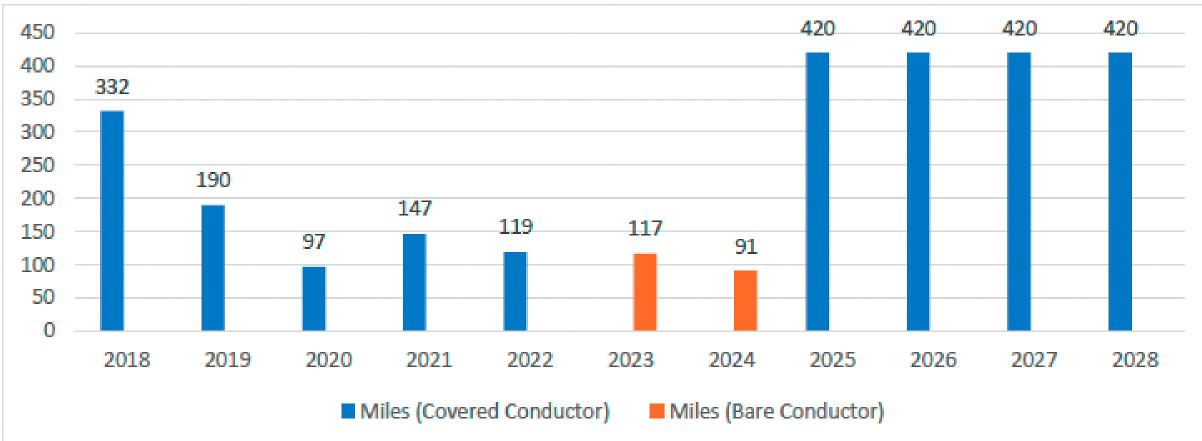
replacement] planning purposes is fundamentally a 'practical impossibility' given the inherent uncertainties in forecasting a distribution asset's lifespan and would not provide meaningful information." D.21-08-036, p. 44, citing SCE's opening brief.

[153] TURN further addresses Machine Learning-related issues in the policy discussion of Section 3.2 of this brief.

[154] *Id.*, pp. 40-41.

of the utility's 40,000 primary overhead distribution circuit miles.[155] The utility proposes to reconductor approximately 420 circuit miles per year starting in 2025, a figure that is two to four times higher than any year since 2019.



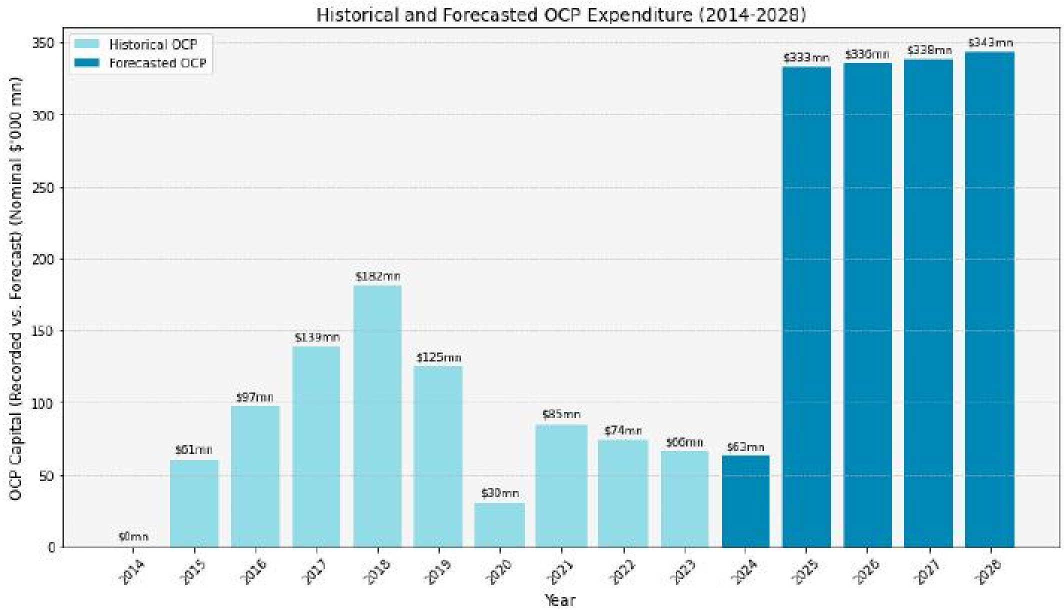
Overhead Conductor Program Circuit Miles
(2018-2022 recorded vs. 2023-2028 proposed)[156]

And the associated cost is approximately $333 million per year beginning in 2025, again a figure that outstrips any previous year's spending level.[157]

[155] Ex. TURN-05-E, Figure 19.

[156] Ex. TURN-05-E, p. 45, Figure 20.

[157] *Id.*, p. 42, Figure 18.



- **SCE's unprecedented Overhead Conductor Program is not adequately supported.**

The Commission should determine that SCE has not sufficiently justified its extensive reliance on reconductoring in non-HFRA territory during the upcoming GRC period, particularly without showing how it complements other cable and conductor replacement programs—such as the Cable-In-Conduit Replacement Program, Cable Life Extension Program, Underground Cable Replacement, and Worst Performing Circuit—that could collectively enhance the safety and reliability benefits attributed to the Overhead Conductor Program. Furthermore, of the 1,666 miles proposed for reconductoring during this GRC period, 1032 miles are "large gauge" wires for which the utility has failed to demonstrate that the associated safety and reliability benefits warrant including wires of that gauge, as opposed to the 634 miles of small gauge wire, the gauge that has historically been the focus of this project.[158] In addition, SCE's proposed

[158] Note that in its description of the OCP, SCE references 1,680 miles of circuit miles replacement. Based on TURN's calculations from TURN-SCE-072 (Q01 a,b), the total circuit miles sum to 1,666 miles

replacement of over 200 miles of bare wire conductor with like kind conductor, even while SCE suggests that bare wire conductor has disadvantages under such circumstances, makes no sense and should not be funded in rates.[159]

- **Cost-Benefit of OCP, accuracy of ML modeling, and an analysis of the synergy of OCP with other DIR programs is notably absent in SCE's analysis.**

There are a number of reasons why the Commission should substantially scale back SCE's request for its non-HFRA Overhead Conductor Program in this GRC. First, the Commission needs to keep in mind that the $330 million per year that SCE proposes to spend on overhead reconductoring activities covered in this GRC represents only a portion of the utility's total overhead reconductoring activities. That is, it represents something of an initial payment because if the Overhead Conductor Program is approved as requested, all 40,000 primary overhead circuit miles in SCE category would seem eligible for overhead reconductoring in subsequent GRCs.[160] Relatedly, there is a notable absence of any analysis of potential synergies between the Overhead Conductor Program (OCP) and other Distribution Infrastructure Replacement (DIR) cable and conduit replacement programs, such as the Cable-In-Conduit Replacement Program (CiC), the Cable Life Extension Program (Cle), and the Worst Performing Circuit (WPC). The Commission should adopt a scaled-back figure, rather than one that is based on such assumptions and omissions.

(1032 large gauge + 634 small gauge wires). Ex. TURN-05-E, Attachment 2, Response to TURN-SCE-072 (Q01 a,b).

[159] Ex. TURN-05-E, pp. 41-45.

[160] *Id.*, p. 44. (This includes 8,500 miles of Wildfire Covered Conductor Program (WCCP), as well as 1,500 HFRA miles not included in WCCP and 30,000 non-HFRA miles as part of OCP.)

Second, the Commission should be concerned with the proposed scale of the GRC-proposed program. SCE's proposal to replace 1,680 miles of fully functional overhead conductors represents a 133% increase in forecasted costs compared to the 2017-2022 period, setting SCE down an exceedingly costly path without a sufficient demonstration that the program is clearly cost-effective and otherwise reasonable.[161] SCE has presented no evidence that the impact such programs have on affordability of electricity service is even considered in the utility's decision-making process. Covered conductor is one of the costliest mitigation measures available to the utility and should be used only where less costly alternatives are inadequate. It is not just a matter of the cost of the covered conductor itself, which is approximately 1.3 times more expensive than bare conductor. The covered conductor is approximately 1.5 to 1.9 times heavier than bare conductor, increasing the likelihood that a reconductoring project will need to also include replacement of poles and other equipment sized for bare conductor but inadequate for covered conductor. There are also reduced ampacity issues and the potential for premature insulation breakdown that all suggest SCE's proposal to rely on covered conductor on a more widespread basis is not reasonable.[162]

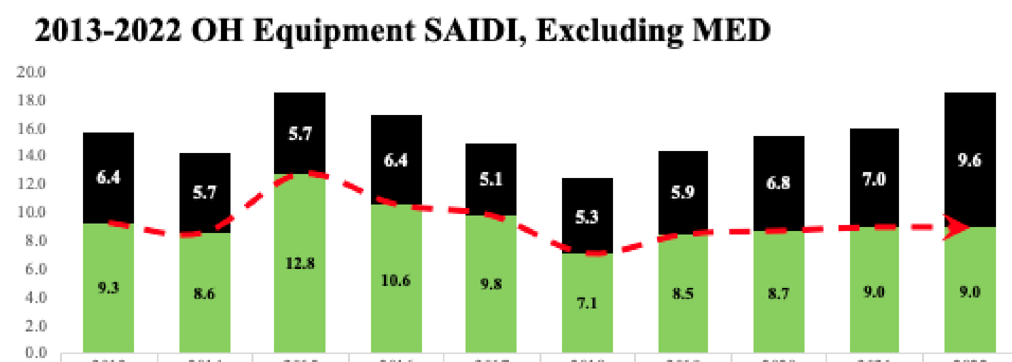
Third, the reliability benefits of covered conductor as compared to bare conductor are likely exaggerated. As TURN's testimony demonstrated, SCE's reliability data is already improving with the current Infrastructure Replacement programs and recent far lower spending levels, a trend achieved without the proposed shift to covered conductor in non-HFRA areas.[163] SCE's attempt to counter that assertion through the illustration presented in Figure II-10 of its

[161] *Id*.

[162] *Id.*, pp. 45-46.

[163] *Id.*, pp. 46-47.

rebuttal testimony falls short, as it actually confirms TURN's claim that the SAIDI figure for overhead conductor and ancillary equipment ("Conductor / Splice / Connector / Tap") has been generally lower during the 2018-2022 period than the figures during the 2013-2017 period, while the SAIDI figures for "Other Overhead Equipment" drives the trend line in SCE's version of the table.[164] Below is the same Figure II-10, but with the trend line redrawn to reflect SAIDI for only the overhead conductor and ancillary equipment.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Other Overhead Equipment	6.4	5.7	5.7	6.4	5.1	5.3	5.9	6.8	7.0	9.6
Conductor / Splice / Connector / Tap	9.3	8.6	12.8	10.6	9.8	7.1	8.5	8.7	9.0	9.0
Conductor / Splice / Connector / Tap	9.3	8.6	12.8	10.6	9.8	7.1	8.5	8.7	9.0	9.0

Conductor / Splice / Connector / Tap   Other Overhead Equipment   Conductor / Splice / Connector / Tap

And as a general matter, SCE's proposed new program scope includes in excess of 1,000 miles of large gauge conductor that were not included in the utility's 2022 RAMP filing leading up to this GRC. SCE has not adequately analyzed the safety and reliability benefits of this expansion, nor provided sufficient Risk Spend Efficiency (RSE) scores for it.[165] Despite TURN's opposition

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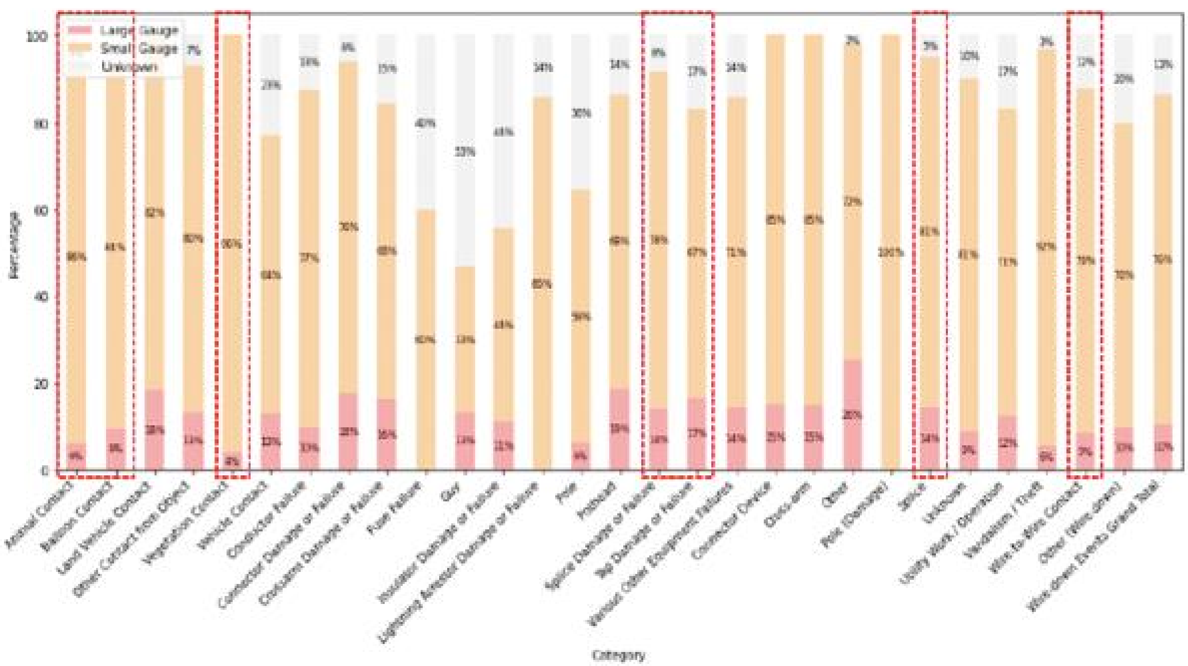
[164] Ex. SCE-13, Vol. 1, p. 41, Figure II-10; "Other OH equipment" could be switches, transformers, capacitor banks. Ex. TURN-05-E, p. 47, citing response to TURN-072, Q. 5.c.

[165] *Id.*, p. 49. The Safety Policy Division (SPD) report on SCE's RAMP application labeled SCE's tranche analysis of its Contact with Energized Equipment (CEE) Risk – which only covers small gauge wire - as lacking reliability and financial consequences from the calculation of risk scores, and being not in compliance with the Settlement Agreement requirement regarding the level of granularity expected in the showing for this risk. SPD Staff Evaluation Report in A.22-05-013, p. 42.

to SCE's use of covered conductors in non-HFRA areas, if the Commission chooses to authorize the utility to proceed in this manner, it should also direct SCE to specifically target replacing small gauge wire, as this approach is better supported by historical data on wire-down incidents.[166]



Fourth, SCE's exclusive reliance on Machine Learning-based models to assess failure possibilities and consequences as part of development of the proposed scope and prioritization is problematic. TURN's prepared testimony describes in some detail the two sub-models that comprise SCE's ML model and the shortcomings of SCE's approach.[167] Yet it was the model

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[166] Ex. TURN-05-E, p. 50, Figure 24 (Large / Small / Unknown Gauge - related wire-down events by Primary Driver (2013- 2022)).

[167] TURN's testimony identified transparency issues (SCE's predictive model lacks detailed information about its algorithms, assumptions, model validity, and data, and validation and verification concerns (the model's effectiveness is questionable without rigorous validation against other potential models with better accuracy). Ex. TURN-05-E, p. 40.

that produced the 1,680 mile estimate of the Overhead Conductor Program's work during the 2025 GRC period. And as noted earlier, the scope of the program as proposed in this GRC is expanded beyond what was described in SCE's RAMP showing leading into the GRC.[168] TURN's testimony presented the results of applying an Ordinary Least Squares model using SCE-provided data, and determined that SCE's risk-reduction modeling suggests near-linear risk reduction for every unit increase in covered conductor length from 680 to 1,680 miles.[169] In contrast, SCE's previous modeling shows significantly diminishing returns from covered conductor in HFRAs, with the first approximately 500 miles showing the steepest safety and

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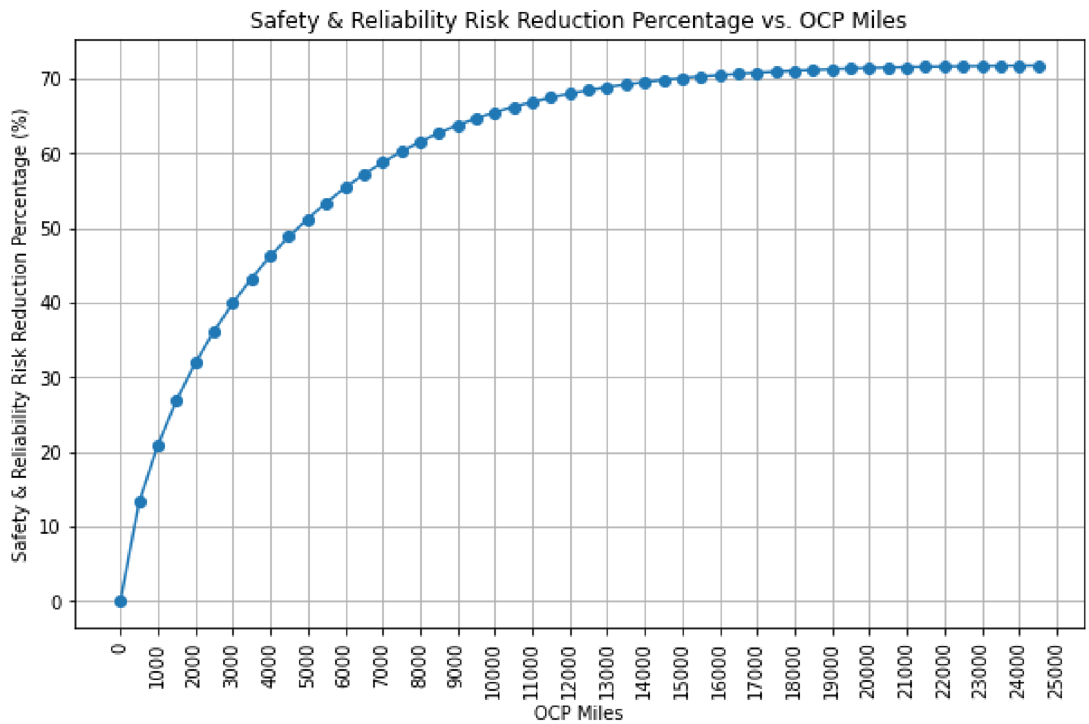
TURN also raised a general critique regarding the cost-benefit imbalance. SCE's RSE scores for the OCP increased from an RSE score of 48 in the RAMP to184 in the GRC as detailed in Table II-24, page 98 of SCE-02, Vol. 1, Pt. 2. Part of this discrepancy may be due to the fact that the RSE / Benefit Cost Ratio (BCR) calculations in the RAMP filing considered only small gauge wires as mitigations, and large gauge wires were introduced to SCE's proposal post-RAMP, and without any supporting benefit-cost analysis included. *Id.*, pp. 56-57.

[168] Ex. TURN-05-E, p. 49.

[169] *Id.*, pp. 52-53.

reliability benefits as shown in the figure below.[170]



TURN's recommendations for the Overhead Conductor Program (OCP) are as follows:

- The Commission should deny funding for the entire program other than the Accelerated OCP (AOCP) element. SCE's proposal to spend upwards of $330 million annually (from 2025-2028) would be unduly burdensome on ratepayers, and unlikely to achieve the projected reliability and safety benefits.

- If the Commission chooses to authorize funding for more than the Accelerated OCP element, the funding should be tied to small-gauge conductor replacements (634 miles of the 1,680 miles SCE has proposed) consistent with the higher failure probability of such conductor and, by extension, the higher projected safety and reliability benefits from focusing on their replacement.

- The Commission should deny ratepayer funding for replacements using bare conductor. While SCE's proposal involves a relatively modest funding request, the plan to replace

[170] *Id.* The figure is from Ex. TURN-110, using data SCE provided in its response to TURN DR 125, Question 4.

208 miles of bare conductor with ratepayer funds in 2023-’24 contradicts their own arguments presented in the Overhead Conductor Program (OCP). The utility's data has previously shown that bare conductors are linked to energized wire-down events, which compromise both safety and reliability.

- The Commission should direct SCE to assess the benefits and costs of alternatives such as replacements of splice, connector or tap equipment as a lower-cost alternative to conductor replacement.

- Going forward, SCE must take steps to ensure that its reliance on machine learning (ML) models are less opaque, such as sharing the assumptions, testing multiple models, showing confidence intervals and ranges in results, and demonstrating the final model’s performance against other potential models.[171]

The authorized spending for the 2023-2025 forecasts resulting from TURN’s recommendations would be $111.76 million, as compared to SCE’s proposal for $458.451 million over that period.

6.1.2 Underground Cable Replacement

SCE’s Underground Cable Replacement Program aims to preemptively address risks in high-risk primary underground cables.[172] SCE reports spending approximately $6 million to $18 million per year in the 2021-2024 period, but proposes to spend an average of approximately $100 million per year for the 2025-2028 period.[173] The cumulative amount for 2023-2028 represents a 37% increase to the cumulative recorded amount for 2017-2022.[174]

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[171] TURN further addresses Machine Learning-related issues in the policy discussion of Section 3.2 of this brief.

[172] Ex. SCE-02, Vol. 1, Part 2, pp. 28-29.

[173] Ex. TURN-05-E, p. 55, Figure 27.

[174] *Id.*, p. 37, Figure 15. The “% difference” figure in the table is stated as 14% between 2017-2022 vs. 2023-2028. $416.45 million is $112.51 million higher than the recorded figure of $303.94 million, and $112.51 million is approximately 34% of $303.94 million.

- **Root Cause Investigations in "Ghost" Cable Failures are necessary before authorizing funding for cable replacement.**

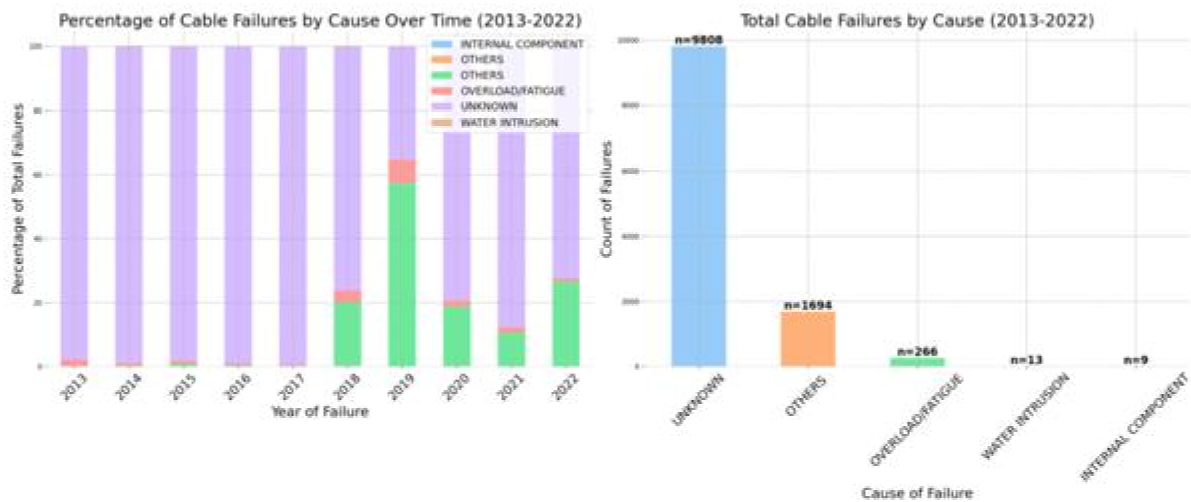
SCE's proposed program scale for the Underground Cable Replacement Program again is tied to ML-based predictive analytics. The concerns with such an approach here are similar to those identified earlier with regard to the utility's Overhead Conductor Program, particularly about the lack of transparency surrounding the forecast.[175] The Commission should not authorize funding without first ensuring that the underlying predictive analytics accurately identify high-risk scenarios without leading to unnecessary replacements.[176]

SCE's analysis is also questionable because the substantial majority of the cable failure causes tracked by the utility fall into the "other" or "unknown" categories. As Figure 28 of TURN's testimony (replicated below) illustrates, any analysis of cable failures tied to a specific cause is an analysis of only a very small proportion of the overall cable failures, and thus is of limited analytical value. The Commission should require SCE's showing to take a more nuanced approach with better information supporting a root cause analysis.[177]

[175] Again, TURN's testimony identified transparency issues (SCE's predictive model lacks detailed information about its algorithms, assumptions, and data, making it hard to assess its accuracy) and validation and verification concerns (The model's effectiveness is questionable without rigorous validation, potentially leading to misclassification of risk levels). Ex. TURN-05-E, p. 40. Here there is also a cost-benefit imbalance, as the significant investment in SCE's aggressive replacement strategy may not result in proportional benefits given that the causes of more than 90% of cable failures is "unknown" or "other. *Id.*, p. 57, Figure 28. Finally, there are also concerns about the shift in methodology, that is, the shift from an age-based to a risk-based replacement model, a change that introduces complexities that could result in resource wastage or increased failure risks if not managed accurately. *Id.*, p. 56.

[176] Ex. TURN-05-E, p. 56.

[177] *Id.*, pp. 56-57.



TURN advocates for a data-driven age threshold for underground cable replacement.[178] Furthermore, when proposing replacements for equipment below the established age threshold, detailed justification should be mandatory. This justification should extend beyond the standard evidence required for such equipment, including additional documentation that demonstrates all preventative measures have been exhausted. It should also clearly establish that the need for replacement is not merely due to preventative or corrective maintenance issues or delays, which should be substantiated by specific notification orders.[179]

TURN's recommendation for the Underground Cable Replacement Program is that the Commission authorize funding based on 800 miles of such replacement, rather than SCE's proposed 1,600 miles, as the reduced number of miles will still enable achievement of 60-70% of the safety and reliability benefits according to SCE's models. The resulting funding for the

[178] TURN's analysis suggests the existing 41-year threshold for mainline cable replacement might need to be lowered, based on historical failure rates and transparent age determination. Ex. TURN-05-E, pp. 57-58.

[179] *Id.*, p. 9

2023-2025 period on a forecast basis is $65.15 million, as compared to SCE's forecast of $114.1 million for that period.[180]

6.2 Inspection And Maintenance, And Capital-Related Expense

TURN's analysis revealed a declining trend in the number of "closed notifications" for both preventive and breakdown maintenance.[181] "Closed notifications" indicate the completion of identified maintenance work by SCE. If SCE maintained a rising or stable trend in completed maintenance notifications, it would suggest effective maintenance management, and the Commission could reasonably anticipate a reduction in the need for capital replacements.[182] But instead, SCE's numbers for closed notifications for both preventive and breakdown maintenance reflect a generally downward trend over much if not all of the 2018-2022 period. Such a trend may suggest reduced levels of routine maintenance and, by extension, a need for increased capital expenditures.

- **SCE's pattern of declining trend in maintenance notifications and Inspect App efficacy.**

In its rebuttal testimony, SCE only challenged TURN's analysis on the basis of TURN having relied on "closed notifications" that reflected the year the maintenance need was <u>found</u> rather than the year the maintenance was <u>closed</u>.[183] In discovery, SCE provided TURN with the 2018-2022 data that reflected the year the maintenance was <u>closed</u>. The pattern TURN had identified in its testimony was virtually unchanged.[184]

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[180] *Id.*, pp. 55 and 58 (Figure 29).

[181] Ex. TURN-05-E, pp. 9-10.

[182] *Id.*, p. 10.

[183] Ex. SCE-13, Vol. 2, p. 28.

[184] Ex. TURN-100 (Response to TURN-115, Question 5 and TURN graphs based on the provided data for 2018-2022). SCE's data request response chose to add 2023 data as well, likely to permit the utility to

TURN also raised concerns regarding the extent of SCE's reliance on "Inspect App," a software used as part of SCE's inspection process that requires entry of responses to 80-161 survey questions and mandatory photographs for each structure, as part of its inspection process. The reliance on Inspect App rather than its predecessor required additional equipment and contractors to support the inspection process, and by SCE's calculations has tripled the amount of inspection time per structure.[185] TURN's analysis shows the claimed tripling of inspection time per structure is understated.[186] Furthermore, the benefit of this expanded use of Inspect App and the increased costs associated with the extra materials, consultants, and inspection time remains unsubstantiated.

TURN does not present a specific forecast adjustment tied to the reliance on Inspect App within SCE's Distribution Ground Inspections program, due to a lack of relevant supporting data supporting the use of Inspect App. However, the Commission should direct SCE to reevaluate its use of the more extensive (and expensive) inspection effort for routine and compliance-based inspections outside of the High Fire Threat District, due to its unproven efficacy for such purposes. and consider relying instead on the inspection methods that preceded the increased reliance on Inspect App beginning in 2020.

TURN's recommendations for Inspection and Maintenance and Capital-related Expense are:

- The Commission should direct SCE to reevaluate and, as appropriate, scale back its deployment of and reliance on Inspect App for routine and compliance-based inspections,

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point out the "uptick" such data would create if it were included in TURN's graphs. Ragsdale, SCE, 4 RT 421, ll. 9-14. TURN does not disagree that the 2023 data creates an uptick from the 2022 data, but it also does not materially change the overall trend for the 2018-2022 period.

[185] Ex. TURN-05-E, p. 12.

[186] *Id.*, p. 14.

given the clear underestimation of time and resources needed for Inspect App over traditional inspection methods, especially outside of High Fire Threat Districts.

- The Commission should direct SCE in its next GRC showing to analyze and address any trends in preventive or corrective maintenance and the impacts on associated capital replacement activities, broken out by each category of Distribution Infrastructure Replacement activity. This review should consider, at minimum, any trends in maintenance completion as indicated by "closed notifications."

6.3 Safety And Reliability Investment Incentive Mechanism

7. METER ACTIVITIES

7.1 Meter O&M

7.2 Meter Capital

8. TRANSMISSION GRID

8.1 Transmission Grid O&M

8.2 Transmission Grid Capital Expenditures

8.3 Transmission Infrastructure Replacement

9. SUBSTATION

9.1 Substation O&M

9.2 Substation Capital

9.3 Substation Infrastructure Replacement

SCE's Substation Infrastructure Replacement Program focuses on pre-emptive replacement of equipment and structures based on a determination they are in poor condition per the utility's heath index, aged and obsolete.[187] SCE's direct testimony forecasted $1.629 billion for substation infrastructure replacement from 2023 to 2028. The upward trajectory of such replacement expenditures is coupled with a downward trend in the volume of routine maintenance activities, which TURN submits must raise concerns with the Commission.[188] TURN recommends a relatively small reduction to SCE's forecast for this GRC period, and a directive to the utility to implement more stringent verification of replacement needs based on a more rigorous and transparent analysis of the various components of its health indices, unit cost calculations underlying its forecasts, and the actual condition of equipment.

9.3.1 Circuit Breaker Replacement Program

SCE's Circuit Breaker Replacement Program has displayed a pattern of recording high costs for the replacement work, even in years when it is replacing a far lower number of units. In order to better understand SCE's costs and practices, the utility needs to provide more granular data for the circuit breakers being replaced, particularly the varying voltage levels and their corresponding unit costs.[189]

- **SCE's incorrect unit cost calculations, non-linear Health Index scale, and faulty Weibull analysis.**

SCE's records reveal approximately 70 in-service circuit breaker failures over the last thirteen years, for a failure rate of approximately 0.04% per year. TURN agrees that SCE should make reasonable efforts to avoid having such equipment fail in service, but the utility needs to develop a more effective replacement strategy to ensure reasonable costs. This is particularly so

[187] Ex. SCE-02, Vol. 5, p. 132.

[188] Ex. TURN-05-E, p. 16.

[189] Ex. TURN-05-E, pp. 16-17.

where, as here, SCE seeks funding to proactively replace 1,190 during this GRC period, or approximately 10% of the 13,000 circuit breakers currently in service.[190] For example, SCE fails to provide data regarding reliability-related or safety-related costs and impacts incurred due to circuit breaker failures, and does not address how its proposed program would reduce those costs or impacts. Similarly, the utility does not track benefits from its prior replacements in terms of improved safety or reliability. Rather than a deliberate, targeted replacement approach supported by data, SCE replaces equipment more as opportunities arise, an approach TURN's testimony likened to playing whack-a-mole.[191]

The analysis of circuit breaker replacements needs to keep in mind the various other layers of defense that serve to avoid catastrophic failures and ensure system reliability and safety. TURN's testimony identified two other major Substation Infrastructure programs (Relays, Protection and Controls Replacement, and Substation Rebuilds), both of which have substantial forecasted capital spending and neither of which TURN is challenging here.[192] It is reasonable to expect there will be synergies among these various programs that may reasonably be expected to reduce the need for circuit breaker replacements. For example, upstream relay protection or fuse-based systems are designed to preemptively isolate a circuit breaker prior to a "catastrophic failure" occurring. Preventive measures like regular maintenance and thermal imaging, along with the unexplored synergies of SCE's major substation programs, may contribute significantly to system reliability and safety without the immediate need for costly

[190] Ex. TURN-05-E, p. 20.

[191] Ex. SCE-13, Vol. 5, p. 37 (SCE refers to "operational efficiencies" as an umbrella term for replacements that are not justified based on its own health index); Ex. TURN-5-E, pp. 18-19.

[192] Ex. TURN-5-E, p. 19. The test year 2025 forecasts for "Relays, Protection and Controls Replacement" and "Substation Rebuilds" are $91.1 million and $72.3 million, respectively.

replacements.[193] The forecast for circuit breaker replacements should reflect a more integrated analysis of the various programs and practices that will impact replacement needs, rather than assessing substation equipment replacements as if they were a stand-alone activity.

SCE's "health index" based positions are undercut by the utility's deployment of a non-linear scale. Rather than rely on SCE's index as presented, the Commission should direct the utility to revise the underlying index to apply a linear scale going forward. Per its health index, SCE asserts that of the approximately 12,900 circuit breakers in service, 2,000 are in "Poor" or "Very Poor" condition. The Health Index developed by SCE integrates various parameters—sulfur hexafluoride gas purity for SF6-based CBs, oil circuit breaker analysis for oil CBs, operational frequency, contact resistance tests, and overstress percentages. But the underlying calculations add up to 175% of the number of circuit breakers, rather than the 100% as one would expect for a weighted scoring scale.[194] Furthermore, the non-linear nature of SCE's scale results in an overestimation of the number in the "poor" and "very poor" categories.[195] Finally, SCE applies its health index in a non-uniform manner, as its recorded and forecasted replacements include a number of circuit breakers that fall into the "Very Good" to "Fair" condition categories, without any clear justification for those replacements.[196] SCE's implementation of a non-linear scale has led to an overestimation of equipment in poor and very poor conditions.

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[193] *Id.*, pp. 19-20.

[194] *Id.*, p. 21.

[195] Ex. TURN-107 (Response to TURN DR 115, Question 2 and associated TURN calculations). In the linear scale, the sum of 'Poor' and 'Very Poor' circuit breakers is 13.1%, and for transformers, the corresponding sum is 8.6%. Conversely, in the non-linear scale, circuit breakers classified as 'Poor' or 'Very Poor' sum to 16.3%, while transformers in these categories total 20.2%.

[196] Ex. TURN-05-E, p. 23.

The Commission should also not rely on the results of SCE's Weibull reliability analysis. Weibull analysis is a statistical model used for forecasting failure rates and assessing product reliability based on historical data. Though the Weibull model is frequently used in reliability analysis, the outputs can only be as good as the inputs, and TURN's analysis demonstrated that SCE's model inputs were fundamentally flawed.[197] In addition, SCE used a relatively small data set (from 2016-2022) to predict failure rates extending for a twelve-year period (2023-2034), without justifying why it did not use pre-2016 available data. And SCE did not meaningfully evaluate any alternatives to the Weibull model.[198] In light of these elements, the Commission should not place any stock in SCE's Weibull-based analysis.

One clear area for improved efficacy of this program would be to target replacement of Oil and Air Magnetic circuit breakers, as the median age of that equipment is 59 years, a dramatic difference as compared to the median ages of 16 and 10 years for Gas and Vacuum circuit breakers, respectively.[199]

SCE's analysis was not helped by the utility's reliance on erroneously escalated unit costs in its calculations. TURN's testimony had flagged the incorrect arithmetic underlying SCE's figures, due to the utility having applied double escalation. Correcting for this double escalation resulted in a 2% reduction to SCE's average cost figure for circuit breakers in the 220-500 kV voltage class, and a 46% reduction for the 2.4-115 kV voltage class.[200] SCE's rebuttal

[197] Ex. TURN-05-E, p. 25. TURN described how SCE assumed that "replacement rates" were the same as "failure rates," as if all replacements had been the result of an in-service failure, when in fact there were relatively few in-service failures.

[198] *Id.* TURN's testimony identified lognormal and gamma models as alternatives that could potentially provide better estimates – or at least provide a relative comparison against Weibull-based point estimates.

[199] Ex. TURN-05-E, p. 25.

[200] Ex. TURN-05-E, pp. 20-21.

testimony simply denied the error, without any indication that the utility had checked its calculations.[201] In response to a TURN data request, SCE appears to have re-checked its calculations, and acknowledged that it had incorrectly applied escalation.[202] Given that the double-escalation issue cropped up in two key programs, TURN recommends that the Commission direct SCE to broaden its review to the remaining two programs (i.e. "Relays, Protection and Control Replacements Program" and "Substation Rebuilds Program") included in its "Substation" volume, and either confirm that there was no double escalation for the other programs, or make the necessary adjustments to its forecast to remove such double escalation.

As a general matter, SCE's direct showing in a GRC should provide detailed workpapers that clearly demonstrate how project-level costs are derived and translate into unit costs. These should also show the flow of these costs from historical project level costs to unit costs and finally into the annual forecasts. This approach ensures basic transparency and allows for verification of unit cost assumptions. SCE should also demonstrate that it has more fully assessed options such as diagnostic testing, refurbishment and remedial work as less costly alternatives to replacement.[203]

TURN's recommendations for the Circuit Breaker Replacement Program are:[204]

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[201] Ex. SCE-13, Vol. 5, p. 32.

[202] Ex. TURN-107 (SCE Response to TURN DR 115, Questions 1, 3 and 4), Response to Question 1. . However, SCE also took the opportunity to identify another error that it claimed caused its unit costs to be understated and included adjustments in the utility's favor. TURN did not have a sufficient opportunity to review SCE's additional information regarding purported corrections extending beyond the double-escalation in unit cost issue that both parties had previously addressed in prepared direct and rebuttal testimony, which is not surprising where the additional information arrived at the outset of evidentiary hearings.

[203] Ex. TURN-05-E, p. 20.

[204] *Id.*, p. 27.

- The Commission should authorize $153.13 million rather than SCE's forecast of $164.29 million for the 2023-'25 period, a reduction of approximately 6.8%.

- The Commission should direct SCE to target replacement of only those circuit breakers that are deemed to be in "poor" or "very poor" condition according to SCE's arbitrary, non-linear Health Index. Circuit breakers in "very good," " good," and "fair" condition should not be replaced as part of the Infrastructure Replacement Program.

- The Commission should direct SCE in its next GRC to:
    - Present a more detailed analysis of unit costs, and break out its circuit breaker proposals into more granular voltage classes, rather than relying on two broad classes.
    - Substantiate the accuracy of its chosen health index, or to modify that index to comport with TURN's suggestion of a linear, unbiased index.
    - Develop a replacement approach that, like the 41-year threshold for Cable Replacement, establishes the need to replace substation equipment that fails earlier than a designated age threshold.[205] The Commission should also encourage SCE to engage in a stakeholder-involved process in order to develop such thresholds for equipment included in SCE-02, Vol. 02 ("Substations"). The results of this effort should be reported and reflected in SCE's next GRC showing.

9.3.2 Substation Transformer Bank Replacement Program

TURN's analysis of SCE's proposed funding for the Substation Transformer Bank Replacement Program addressed issues similar to those raised with regard to the Circuit Breaker Replacement Program and discussed in the preceding section of this brief. In addition, after serving its rebuttal testimony, SCE acknowledged that the double escalation error identified for

[205] In the context of substations, while age is incorporated into SCE's health index, establishing a definitive age threshold is crucial. For plant that has not yet reached the established threshold, SCE must present a compelling demonstration to justify equipment replacements. TURN's analysis of the age distribution of transformers and circuit breakers suggests a median age of 9-23 years for circuit breakers and 12-24 years for transformers, indicating that the overall fleet is relatively new.

its circuit breaker unit cost calculations extended to its unit cost calculations here as well, and provided corrected figures.[206]

- **Persistent Incorrect Unit Cost Calculations, Skewed Health Index, and Faulty Weibull Analysis.**

TURN's prepared testimony summarized issues such as the absence of data that might support SCE's unit cost calculations, the use of a non-linear health index, and errors in SCE's calculation of the rate of replacement and its Weibull analysis.[207] The current replacement strategy lacks sufficient justification in unit cost calculations and health index assessments, leading to potentially unnecessary replacements. Historical data does not support the urgency of replacing transformers with a median age well below industry standards for end-of-life, particularly those categorized as being in 'Good' or 'Fair' health.

TURN's analysis suggests a median age of 12 years for A-Bank transformers, and 24 years for B-Bank transformers, suggesting a reduced need for a preemptive replacement strategy given the longer lives expected for such equipment.[208] And TURN explained that under SCE's approach the utility would include replacements of 94 transformers in "fair" or "good" condition under SCE's own non-linear health index, out of a total of 298.[209]

SCE justifies its use of the biased non-linear Health Index scale by citing Transformers Magazine, Vol. 7, Issue 4 from 2020 in its rebuttal.[210] The referenced table (titled "Table I – Health Index Reference Scale") suggests only "Poor" and "Very Poor" health condition

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[206] Ex. TURN-107 (SCE Response to TURN DR 115, Questions 1, 3 and 4), Response to Question 4.

[207] Ex. TURN-05-E, pp. 30-31.

[208] Ex. TURN-05-E, p. 32.

[209] *Id*.

[210] SCE-13, Vol. 05, footnote 82.

transformers may be "at end-of-life," and only those in the "Poor" and "Very Poor" categories are likely to warrant preemptive replacement during the GRC period.

HI	Condition	Description	Expected Lifetime
85 - 100	Very Good	Minor deterioration	≥ 15 years
70 - 85	Good	Significant deterioration	≥ 10 years
50 - 70	Fair	Widespread deterioration	Up to 10 years
30 - 50	Poor	Serious deterioration	≤ 3 years
0 - 30	Very Poor	Extensive deterioration	At end-of-life

TURN's recommendations for the Substation Transformer Bank Replacement Program are:[211]

- The Commission should authorize funding of $152.93 million rather than the $182.00 million for the 2023-'25 period, a reduction of approximately 6.9%. This level of funding is consistent with replacement of 86 transformer banks from 2023-'25, as opposed to SCE's proposal of 98 for the same period.[212]

- The Commission should direct SCE to target replacement of only those substation transformers that are deemed to be in "poor" or "very poor" condition according to SCE's non-linear Health Index. Transformers in "very good," "good," and "fair" condition should not be replaced as part of the Infrastructure Replacement Program.

- The Commission should direct SCE in its next GRC to:
    - The Commission should direct SCE to develop a replacement approach that, like the 41-year threshold for Cable Replacement, establishes the need to replace substation transformer banks above an age-based threshold that relies on historical data of in-service failures. For equipment that has not reached a specified age threshold, the utility should be required to demonstrate that all preventive, refurbishment, and other maintenance measures have been exhausted before justifying replacement.

[211] *Id.*, pp. 33-34.

[212] *Id.*, p. 34.

- The Commission should also encourage SCE to engage in a stakeholder-involved process in order to develop such thresholds for substation transformer banks and other categories of equipment. The results of this effort should be reported and reflected in SCE's next GRC showing.

- The Commission should direct SCE to present unit cost and annual forecast information at a more granular level for assets like circuit breakers and transformers, such as by specific voltage classes rather than "A-bank" and "B-bank" transformers. The more granular showing should at a minimum extend to unit costs, recorded and forecasted costs, and health condition assessments to provide a clearer understanding of asset management and investment needs.

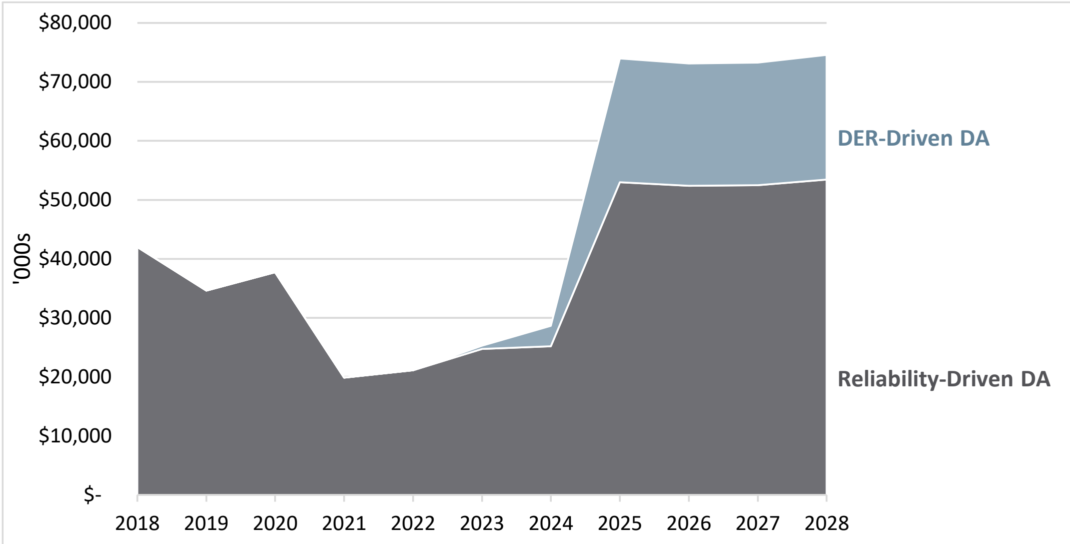
10. GRID MODERNIZATION, GRID TECHNOLOGY, AND ENERGY STORAGE

10.1 Grid Modernization

SCE proposes to approximately double its investments in distribution automation, from an average of $31 million per year over the period 2018-2022 to an average of $74 million per year for the period 2025-2028.[213] This rapid increase in investment is shown in the figure below.

[213] Ex. TURN-06E, p. 2, citing SCE-02 Vol. 06, May 12, 2023, Table II-6, p. 35.

Figure 1. SCE proposed investments in distribution automation[214]



SCE claims that this distribution automation will provide "system operators with additional visibility, situational awareness, and control,"[215] and will increase its ability to respond to dynamic grid conditions to maintain reliability and facilitate the ability of DERs to provide services to SCE's distribution system.[216]

For the period 2025-2028, SCE proposes to invest $295 million related to distribution automation, at a rate of about $74 million per year for the 2025-2028 period. Although this represents more than a doubling in capital expenditures relative to recent years, SCE proposes to upgrade approximately the same number of circuits annually (approximately 100 circuits per year) as it has in recent years.

SCE asserts that its distribution automation investments would be cost-effective in terms of delivering reliability benefits to customers. However, these investments must be viewed in

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[214] Ex. TURN-06E, p. 2, citing Ex. SCE-02 V06, p. 35.

[215] Ex. SCE-02 Vol. 06, p. 98.

[216] Ex. SCE-02 Vol. 06, p. 98.

light of the affordability crisis facing California ratepayers. While improved reliability is desirable, it must be balanced against cost. Given the massive rate increase that ratepayers are already facing, it is not the time to double spending on reliability. Instead, TURN recommends that SCE continue a measured approach to implementing distribution automation at a rate of approximately $32 million per year and targeting the circuits with the highest benefit-cost ratios.

TURN developed a scaled back proposal by limiting the number of circuits upgraded to those with the highest net benefits in SCE's BCA workbook. Under TURN's proposal, the weighted average benefit-cost ratio under the 3/3 scheme would be increased to 9.5 and 9.3 for reliability-driven and DER-driven circuits, respectively, and would provide ratepayers with a savings of $168 million relative to SCE's proposal. Alternatively, SCE could address substantially more circuits through implementing a 2/2 scheme. Under TURN's alternative proposal, SCE could upgrade 190 reliability-driven circuits and 60 DER circuits using a 2/2 scheme for $170 million less. This alternative proposal has a BCR of 9.0 and 8.5 for reliability-driven and DER-driven circuits, respectively.

The table below summarizes TURN's primary proposal (3/3 scheme) and alternative proposal (2/2 scheme) relative to SCE's proposal. The results show how the benefit-cost ratio could be increased and costs be reduced by targeting a more limited number of high-impact circuits.

Table 3. TURN's proposed distribution automation upgrades and associated savings

		SCE Proposal (3/3 scheme)	TURN Proposal (3/3 scheme)	TURN Alternative Proposal (2/2 scheme)
Reliability-Driven Upgrades	Number of Circuits	255	138	190
	BCR	6.8	9.5	9.0
	Capex Cost	$211.5 million	$100.2 million	$100.5 million
DER-Driven Upgrades	Number of Circuits	110	45	60
	BCR	4.6	9.3	8.5
	Capex Cost	$83.4 million	$26.4 million	$24.3 million
Total Capex (Reliability + DER)		$295 million	$127 million	$125 million
Savings Relative to SCE Proposal			$168 million	$170 million

Hence, the Commission should adopt TURN's proposal, which is not only more affordable than SCE's proposal (savings of $168 million to $170 million) but also more cost-effective (BCR of 8.5 to 9.5 compared with 4.6 to 6.8 for SCE's proposal). The circuits that are candidates for upgrading under TURN's Proposal (3/3 scheme) and TURN's Alternative Proposal (2/2 scheme) are provided in Appendix B of Ex. TURN-06E.

Response to SCE's Rebuttal. In its rebuttal, SCE claims that its approach to demonstrating the cost-reasonableness of the proposed distribution automation investments consists entirely of a benefit-cost analysis that uses avoided customer outage costs as the benefit,[217] and that adopting TURN's proposal "would negatively impact customers and increase customer outage costs by $940.8 million compared to SCE's proposal."[218] SCE's claim is

[217] Ex. SCE-13V06, p. 15.

[218] Ex. SCE-13V06, p. 15.

misleading as well as unreasonable and should be rejected by the Commission. First of all, the "avoided customer outage costs" asserted by SCE are *not* actual outage costs avoided by SCE customers, nor are they actual avoided costs in SCE's rates – they are calculated values using value of service ("VOS") metrics from a study performed by Nexant that was not reviewed by parties in this proceeding.[219] Furthermore, the study assumes VOS metrics that are highly inequitable – it values momentary outages for residential customers at $4.59 and large customers at $17,696.69,[220] which is 3855 times a residential customer! Yet, residential customers pay more than 50% of distribution related revenue requirement per SCE's latest GRC Phase 2 decision.[221]

Thus, while the VOS metrics could be used to aid the prioritization of SCE's grid modernization efforts, they should not be used as approximations for actual avoided customer outage costs. Hence, SCE's claim that customers would be negatively impacted by adopting TURN's proposal should be rejected.

10.2 Grid Technology Assessments, Pilots, And Adoption

10.3 Energy Storage

The focus of SCE's Long Duration Energy Storage (LDES) proposal is a Thermo-Chemical Energy Storage (TCES) system, which would provide 24-hour duration energy

[219] Ex. SCE-02 V06 WP, p. 70.

[220] Ex. SCE-02 V06 WP, p. 70.

[221] D.22-08-001.

storage. SCE states that the purpose of these pilots is to accelerate the commercialization of non-lithium-ion storage technologies to facilitate greater renewable integration and resiliency.[222]

SCE seeks authorization for $78.158 million in capital expenditures and $0.15 million (normalized) for Test Year 2025 O&M expenses to conduct LDES pilots during the 2025-2028 time period:[223]

Table 4. SCE Proposed LDES Capital Expenditures[224]

	2025	2026	2027	2028*	Total
GRC Forecast	$9,196	$12,254	$18,730	$37,977	$78,158

Although SCE had applied for $140 million in additional funding from the US Department of Energy to support a 24-36 MW TCES pilot, it was not successful in attaining that funding.[225] Because SCE did not receive federal funding, it proposes instead to conduct a smaller, 2 MW pilot TCES project in 2025-2026, and then "to fund technology enhancements to the preliminary TCES pilot and/or additional pilots of other LDES technologies"[226] with the remaining funds during the 2027-2028 period.

Long-duration energy storage is likely to play an important role in the decarbonization of California's grid, and it will be important for utilities, including SCE, to become familiar with these technologies. However, TURN has two significant concerns with SCE's proposal:

[222] Ex. TURN-06E, p. 7, citing Ex. SCE-02 V06, p. 163.

[223] Ex. SCE-02 Vol. 06, p. 172.

[224] Ex. TURN-06E, p. 8, citing Ex. SCE-06 V06, p. 203.

[225] Ex. TURN-06E, p. 8, citing Response to TURN-SCE-054 Q02.a.

[226] Ex. TURN-06E, p. 8, citing SCE-02, Vol. 06, p. 204.

1) The investments that SCE plans to undertake in 2027 and 2028 beyond the core TCES project are ill-defined and not adequately supported; and

2) SCE has not proposed any reporting measures regarding its LDES investments in terms of spending or lessons learned.

In terms of SCE's proposed expenditures beyond the initial pilot, SCE simply notes that it plans to integrate technology enhancements to the TCES and/or conduct additional pilot projects in 2027-2028 that build on the results of the TCES pilot.[227] SCE is vague in terms of what these investments would entail, explaining only that enhancements would "likely include additional energy storage capacity," and that additional pilots are "likely to be of the sodium flow and/or liquid metal battery types."[228]

SCE provides no detailed budget data to support its capital expenditure request of almost $19 million for 2027 and $38 million for 2028 for these enhancements and additional pilots. Further, SCE has not proposed a mechanism for SCE to return any potential underspend to customers, such as a one-way balancing account. Because SCE has not developed a clear scope or budget for its proposed long duration energy storage expenditures beyond the core TCES pilot, TURN recommends that the Commission reject SCE's proposal for LDES capital expenditures of $18.730 million for 2027 and $37.977 million for 2028.

In addition, TURN recommends that any approval for LDES investments be accompanied by annual progress reports that summarize the status of the project and funds

[227] Ex. TURN-06E, p. 9, citing Ex. SCE-02, Vol. 06, p. 199.

[228] Ex. TURN-06E, p. 9, citing Ex. SCE-02, Vol. 06, p. 204.

expended, and that SCE submit a report regarding lessons learned prior to its next GRC application scheduled to be filed in 2027.

In its rebuttal, SCE stated that it agrees with TURN's recommendations.[229]

11. LOAD GROWTH, TRANSMISSION PROJECTS, AND ENGINEERING

11.1 Load Growth

SCE's load growth request from 2025 to 2028 marks a significant increase over the previous GRC period that warrants careful scrutiny as these capital costs will impact SCE customers for decades. TURN's testimony, Exhibit TURN-07,[230] provided detailed analysis and recommendations regarding SCE's forecasts for capital expenditures to support load growth in its 2025 GRC. In Exhibit SCE-13, Volume 7,[231] SCE presents a revised load growth capital expenditure forecast of $3,139 million over the 2023-2028 period, and proposes a rebuttal position of $920.781 million over 2023-2025, including $442.890 million in the 2025 test year.[232] TURN proposes a forecast of $660.922 million over 2023-2025, including $237.339 million in the 2025 test year.

The table below presents the costs forecast and proposed by SCE in its rebuttal testimony, alongside TURN's recommendations. TURN opposes all costs associated with the Transportation Electrification Grid Readiness Plan (TEGR), as well as certain project-specific

[229] Ex. SCE-13 V06, pp. 46-47.

[230] Ex. TURN-07E, Prepared Testimony of Sylvie Ashford Addressing Southern California Edison's Test Year 2025 General Rate Case Load Growth Investments, errata filed April 9 2024.

[231] This volume is broken down into three chapters on load growth, transmission projects, and engineering. TURN only addresses the subset of costs pertaining to the load growth chapter, but this does not imply support for the other portions of SCE's request.

[232] Ex. SCE-13, Vol. 7, p. 7.

costs based on analysis of SCE's workpapers. SCE's rebuttal position varies from its revised forecast in two respects. First, SCE is proposing adoption of its 2023 recorded capital expenditures rather than those forecast in opening testimony. This results in a lower request for load growth in 2023 overall. Second, SCE reduced its forecast for New Capacitors within the System Improvements Program in response to a mathematical calculation error highlighted by TURN, which also results in a lower request.[233] As this correction addresses TURN's recommendation for the System Improvements Program, TURN does not discuss the project category in this brief.

Table 5: Summary of SCE[234] and TURN[235] Recommendations
Load Growth, Capital Expenditures[236]
Nominal $000s

Description	2023	2024	2025	2026	2027	2028	Total (2023-2025)	Total (2023-2028)
SCE Revised Forecast	$ 214,584	$ 299,893	$ 443,059	$ 658,550	$ 782,755	$ 739,820	$ 957,536	$ 3,138,661
SCE Rebuttal Position	$ 178,278	$ 299,614	$ 442,890	-	-	-	$ 920,781	-
TURN Reductions	*$ 12,009*	*$ 42,299*	*$ 205,551*	*$ 305,461*	*$ 372,851*	*$ 342,929*	*$ 259,860*	*$ 1,281,101*
TEGR	*$ -*	*$ 32,674*	*$ 167,367*	*$ 237,357*	*$ 306,650*	*$ 287,289*	*$ 200,041*	*$ 1,031,338*
Project-Specific	*$ 12,009*	*$ 9,625*	*$ 38,184*	*$ 68,104*	*$ 66,201*	*$ 55,639*	*$ 59,818*	*$ 249,762*
TURN Recommendation	**$ 166,268**	**$ 257,314**	**$ 237,339**	*	*	*	**$ 660,922**	*

SCE is requesting 60% more for its 2025 test year capital expenditures compared to 2021, and anticipates spending more than double its load growth capital expenditures over 2025-2028 compared to the most recent GRC period.[237] SCE's load growth request is primarily driven by projects under the Distribution Substation Plan (DSP) and Transmission Substation Plan

[233] Ex. SCE-13, Vol. 7, p. 87.

[234] SCE's recommendations are summarized in Ex. SCE-13, Vol. 7, p. 7 (Table II-6).

[235] TURN's recommendations are summarized in Ex. TURN-07E, p. 2 (Table 1).

[236] As described in Section 41 below and Ex. TURN-17 (Addressing Post-Test Year Ratemaking), TURN is not proposing budget-based attrition year funding for load growth capital expenditures. Reductions for 2026-2028 are displayed in the table solely to provide comparison with SCE's revised forecast.

[237] Ex. TURN-07E, pp. 4-5.

(TSP).[238] Whether or not an increase in load growth funding relative to the prior GRC period is reasonable, SCE has not demonstrated the reasonableness of its Transportation Electrification Grid Readiness (TEGR) project costs (which are more than $1 billion in capital expenditures over the period[239]).

The Commission should not accept SCE's narrative that new sources of demand for electricity automatically equate to higher capital infrastructure costs. New load does not inherently mean new investments are necessary,[240] and as SCE agrees, does not scale linearly with costs.[241] Given significant locational and technical uncertainties associated with load forecasting for new technology groups such as medium- and heavy-duty electric vehicles, there is a meaningful risk that poor infrastructure investments will inequitably harm overburdened ratepayers and increase retail rates, discouraging transportation electrification.[242] These risks and the affordability challenges facing SCE's ratepayers necessitate prudent spending on load growth capital projects.

Further, SCE's history of underspending in this category highlights the need for the Commission to ensure SCE has met its burden in justifying each dollar requested. SCE spent 10.9% less than it was authorized for the Load Growth Business Planning Element (BPE) in the 2021 test year.[243] This variance was driven primarily by underspending of $59 million, or 35.5%

[238] Ex. TURN-07E, p. 5.

[239] $1.031 billion over 2023-2028, according to SCE's revised forecast in Ex. SCE-13, Vol. 07, which corresponds to a 2023-2025 rebuttal position of $200.041 million.

[240] Hearing Transcript, Volume 16, May 22, 2024, p. 1521 (Ashford/ TURN).

[241] Ex. SCE-13, Vol. 7, p. 69.

[242] Ex. TURN-07E, pp. 23-24.

[243] Ex. TURN-07E, p. 28.

of total authorization, for the Distribution Substation Plan (DSP). SCE's 2023 recorded costs were also less than requested overall. SCE spent 46%, or $223.244 million less than forecast across this volume,[244] including significantly less ($49.6 million, 85%) than forecast TSP costs.[245] SCE even spent less ($2.9 million, 8%) than forecast DSP costs, setting aside carryover costs.

The following sections will highlight that SCE has not met its burden to demonstrate that its proposed load growth capital expenditures forecast is just and reasonable due to the myriad of flawed assumptions it relied on when developing the TEGR. Where the Commission is unable to determine that costs are just and reasonable, including because the utility failed to meet its burden of proof, it "can and must disallow those costs: that is, unjust or unreasonable costs must not be recovered in rates from ratepayers."[246] Accordingly, the Commission should adopt TURN's proposed reduction of $259.860 million in capital expenditures from SCE's load growth recommendation over the 2023-2025 period, including a reduction of $205.551 million or 46% of SCE's rebuttal position in the 2025 test year. Approximately 80% of this reduction in the 2025 test year is associated with SCE's supplemental TEGR, and 20% with other projects.

TURN removes costs for capital expenditures associated with SCE's TEGR plan because it was based on many flawed assumptions, including inputs from the 2020 Integrated Energy Policy Report (IEPR) and forecasts from the California Air Resources Board (CARB) 2020 Mobile Source Strategy that have not materialized in the past few years and conflict with the

[244] Ex. SCE-11, p. B-2E3.

[245] Ex. TURN-300, pp. 4-5.

[246] D.18-07-025 (Rehearing of decision denying SDG&E rate recovery of wildfire claims costs), p. 5, quoting D.14-06-007.

California Energy Commission's (CEC's) updated 2022 and 2023 IEPR vintages. This reduction is reasonable because SCE did not employ the best available information in its forecasting, as evidenced by the demand inputs utilized in all other sections of its GRC application, and recorded data. TURN also recommends minimal reductions to non-TEGR projects based on project-specific concerns. These reductions are modest compared to those recommend by Cal Advocates, who demonstrated that aspects of SCE's "base" load growth forecast are also inflated due to reliance on inputs from the 2020 IEPR, making TURN's proposal to remove the costs of the TEGR even more reasonable. The following table presents SCE and TURN's respective forecasts for each component of the Load Growth BPE.

Table 6: Summary of SCE[247] and TURN[248] Recommendations by Project Area Load Growth, Capital Expenditures Nominal $000s

Description		2023	2024	2025	2026	2027	2028	Total (2023-2025)	Total (2023-2028)
Distribution Substation Plan (DSP)	SCE Revised Forecast	$104,135	$193,330	$231,375	$359,188	$362,929	$257,603	$528,840	$1,508,561
	SCE Rebuttal Position	$130,649	$193,330	$231,375	-	-	-	$555,355	-
	TURN Recommendation	**$122,621**	**$155,121**	**$143,717**	**-**	**-**	**-**	**$421,458**	**-**
	TURN Reduction	*$8,028*	*$38,210*	*$87,659*	*$98,880*	*$159,441*	*$116,440*	*$133,896*	*$508,657*
Transmission Substation Plan (TSP)	SCE Revised Forecast	$59,186	$49,318	$143,991	$238,008	$352,897	$412,955	$252,494	$1,256,354
	SCE Rebuttal Position	$8,485	$49,318	$143,991	-	-	-	$201,794	-
	TURN Recommendation	**$4,504**	**$45,228**	**$45,840**	**-**	**-**	**-**	**$95,572**	**-**
	TURN Reduction	*$3,981*	*$4,090*	*$98,151*	*$186,673*	*$193,363*	*$206,150*	*$106,222*	*$692,407*
System Improvement Programs	SCE Revised Forecast	$50,344	$56,270	$46,970	$40,430	$45,852	$47,860	$153,583	$287,725
	SCE Rebuttal Position	$38,205	$55,990	$46,800	-	-	-	$140,995	-
	TURN Recommendation	**$38,205**	**$55,990**	**$46,800**	**-**	**-**	**-**	**$140,995**	**-**
	TURN Reduction	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Land Rights Management	SCE Revised Forecast	$920	$975	$983	$1,015	$1,030	$1,062	$2,877	$5,984
	SCE Rebuttal Position	$939	$975	$983	-	-	-	$2,896	-
	TURN Recommendation	**$939**	**$975**	**$983**	**-**	**-**	**-**	**$2,896**	**-**
	TURN Reduction	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Climate Driven Circuit Ties	SCE Revised Forecast	$0	$0	$19,742	$19,908	$20,047	$20,339	$19,742	$80,037
	SCE Rebuttal Position	$0	$0	$19,742	-	-	-	$19,742	-
	TURN Recommendation	**$0**	**$0**	**$0**	**-**	**-**	**-**	**$0**	**-**
	TURN Reduction	*$0*	*$0*	*$19,742*	*$19,908*	*$20,047*	*$20,339*	*$19,742*	*$80,037*
Totals	SCE Revised Forecast	$214,584	$299,893	$443,059	$658,550	$782,755	$739,820	$957,536	$3,138,661
	SCE Rebuttal Position	$178,278	$299,614	$442,890	-	-	-	$920,781	-
	TURN Recommendation	**$166,268**	**$257,314**	**$237,339**	**-**	**-**	**-**	**$660,922**	**-**
	TURN Reduction	*$12,009*	*$42,299*	*$205,551*	*$305,461*	*$372,851*	*$342,929*	*$259,860*	*$1,281,101*

Consistent with its position across the GRC, TURN is not recommending budget-based attrition year funding. Instead, "all non-wildfire related capital additions should be based on an escalation of the seven-year recorded average of non-wildfire related capital additions" for the post-test years.[249] Further, TURN recommends that "the Commission should deny SCE's inappropriate request to augment its capital attrition mechanism with budgeted amounts for non-

[247] SCE's recommendations are summarized in Ex. SCE-13, Vol 2, p. 7 (Table II-6). SCE does not propose budget-based attrition year funding except for two load growth projects detailed in Ex. SCE-07, Vol. 4.

[248] TURN's recommendations are summarized in Ex. TURN-07E, p. 2 (Table 1). This table presents a lower recommendation in 2023 to reflect SCE's recorded underspending. As described in Ex. TURN-17, TURN does not propose budget-based attrition year funding. Reductions for 2026-2028 are displayed in the table solely to provide comparison with SCE's revised forecast.

[249] Ex. TURN-17, p. 2.

wildfire mitigation projects."[250] If, however, the Commission rules in favor of budget-based attrition year funding for one or more of SCE's load growth projects, TURN would propose incorporating the annual reductions to the load growth forecast identified in the table above.

11.1.1 SCE's Load Growth Forecast is Too High Due to Erroneous Assumptions in the TEGR that Inflate Anticipated Demand

SCE's "base" forecast for each project area in the Load Growth BPE is based on the California Energy Commission's 2020 Integrated Energy Policy Report (IEPR).[251] However, SCE went on to identify additional capital expenditures based on a supplemental Transportation Electrification Grid Readiness (TEGR) plan to reflect incremental new transportation and building electrification load after the state established climate policies that were not included in the 2020 IEPR.[252] The TEGR is a planning methodology developed without stakeholder input or review, based on outdated inputs from the 2020 IEPR, the 2020 CARB Mobile Source Strategy, and opaque customer information. As shown in Ex. TURN-07, significant future uncertainty around load location, technological and behavioral innovations create high risk for ratepayers.[253] About 80% of the TEGR supplemental load comes from transportation electrification.[254] Section IV (A) and (B) of Exhibit TURN-07 address in detail SCE's load forecasting methodology and the key contributors to SCE's unreasonably high load growth forecast. The key flaws with SCE's methodology are highlighted in the following subsections.

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[250] Ex. TURN-17, p. 9

[251] Ex. SCE-02, Vol. 7, p. 17.

[252] Ex. SCE-02, Vol. 7, p. 19.

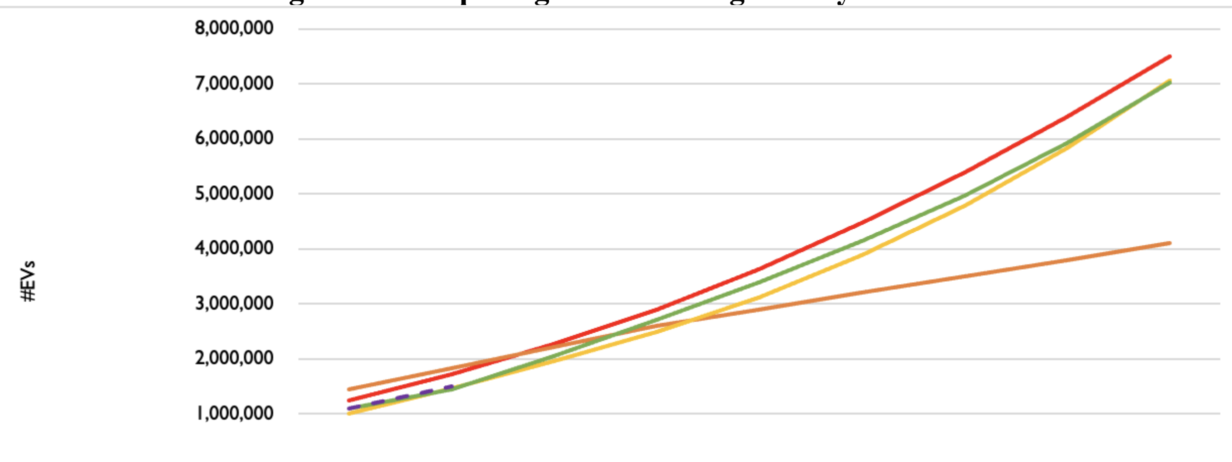
[253] Ex. TURN-07E, pp. 23-24.

[254] Ex. WP SCE-02, Vol. 07 BkA, p. 94.

11.1.1.1 The EV Population Forecast SCE Relies on to Develop TEGR is Inaccurate

SCE based its electric vehicle population forecast on the CARB 2020 Mobile Source Strategy (MSS), an illustrative decarbonization pathway that has been higher by a wider margin than real-world population data each year since 2020.[255] SCE suggests that this forecast is aligned with the latest 2022 and 2023 IEPR updates in years beyond the GRC window. TURN does not agree. SCE assumes an up to 25% larger population of light-duty EVs each year through 2031 as compared to the more recent 2022 and 2023 IEPR updates and assumes more light-duty EVs each year through the end of the forecast (2035) as compared to the 2023 IEPR.[256]

Figure 2: Comparing Statewide Light-Duty EV Forecasts[257]



	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCE TEGR	1,252,848	1,719,977	2,270,409	2,901,023	3,640,262	4,471,600	5,395,349	6,403,925	7,496,817
CEC 2020 IEPR High	1,440,809	1,837,157	2,220,506	2,602,453	2,904,426	3,202,088	3,499,817	3,802,718	4,114,776
CEC 2022 IEPR AATE3	1,005,193	1,459,396	1,957,264	2,495,085	3,118,668	3,884,079	4,791,950	5,843,079	7,063,541
CEC 2023 IEPR AATE 3	1,098,845	1,440,368	2,061,600	2,723,134	3,402,125	4,150,187	4,975,125	5,929,893	7,030,053
CEC actual	1,099,131	1,502,119							

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[255] Ex. TURN-07E, p. 7.

[256] Ex. TURN-302, TURN-SCE-110_Q1, Figure II 2-5.

[257] Forecasts provided in Ex. TURN-302 (SCE Response to TURN-SCE-110) and CEC actual data in Ex. TURN-303 (CEC EV Sales Dashboard Light-Duty and MD-HD 2022 & 2023 Sales Data).

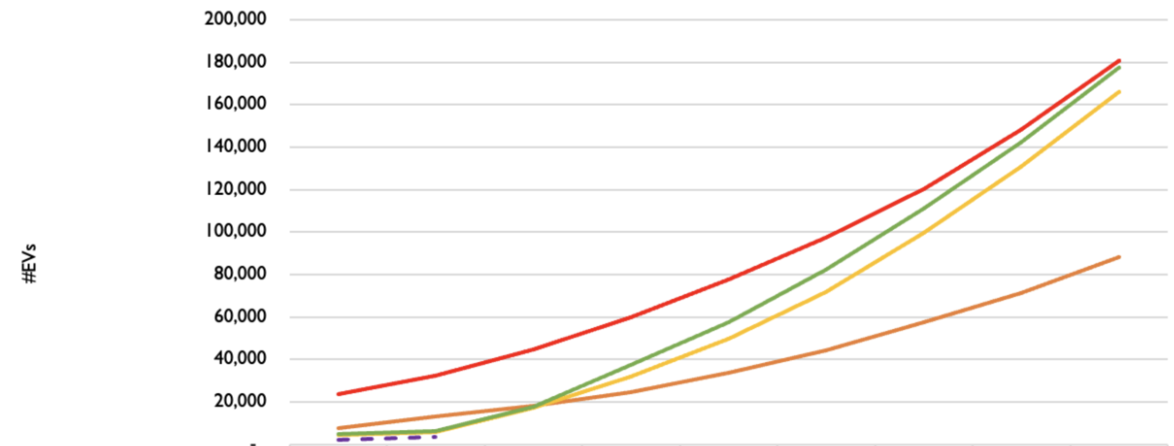
As noted by TURN, Cal Advocates, and NRDC, SCE's medium- and heavy-duty (MDHD) forecast also diverges from recent IEPR updates.[258] SCE assumes an up to 457% larger population of MDHD EVs each year through 2031 as compared to the most recent IEPR updates, and assumes more MDHD EVs through the end of the forecast (2035) than the 2022 IEPR.[259] This includes an unreasonable starting point for the MDHD EV population of 23,453 vehicles in 2022, when the CEC vehicle dashboard reported there were actually just 2,186 such vehicles in California; in other words, SCE's TEGR assumed that there were nearly ten times more MDHD EVs on the road than actually existed statewide. Similarly, the TEGR forecast 32,287 MDHD vehicles in 2023, while the CEC dashboard reflects just 3,581.[260]

[258] Ex. TURN-07, p. 9; Ex. CA-08, p. 19; NRDC-01E, p. 19.

[259] Ex. TURN-302, TURN-SCE-110_Q1, Figure II 2-5.

[260] Hearing Transcript, Volume 16, May 22, 2024, pages 1532-1533 (Ashford/ TURN), see also Ex. TURN-303.

Figure 3: Comparing Statewide Medium- and Heavy-Duty EV Forecasts[261]



	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCE TEGR	23,453	32,287	44,544	59,802	77,702	97,612	120,443	148,334	180,857
CEC 2020 IEPR High	7,852	13,321	18,223	24,807	33,841	44,151	57,733	71,416	88,314
CEC 2022 IEPR AATE3	4,607	5,799	17,425	32,026	49,938	71,981	99,707	131,056	166,079
CEC 2023 IEPR AATE 3	4,855	6,212	17,678	37,524	57,435	82,087	111,076	142,475	177,667
CEC actual	2,186	3,581							

SCE's MDHD forecast diverged from reality well before SCE submitted its application. MDHD EVs are so few that SCE did not have any adoption or population data for its territory when preparing its application and had to invent a baseline territory share of the state's vehicles (33%) and possible load shapes.[262] SCE's Charge Ready Transport Program, which funds electrical system upgrades and charging infrastructure to support charging infrastructure for EV bus and truck fleets, has also seen very slow uptake, and SCE has previously over forecast EV adoption in applications to the Commission.[263] SCE's own internal 2022 Q4 Sales Forecast, which it used for customer demand inputs "consistently throughout all parts of SCE's GRC testimony except for the Load Growth area," overlaps closely with the 2022 IEPR forecast and

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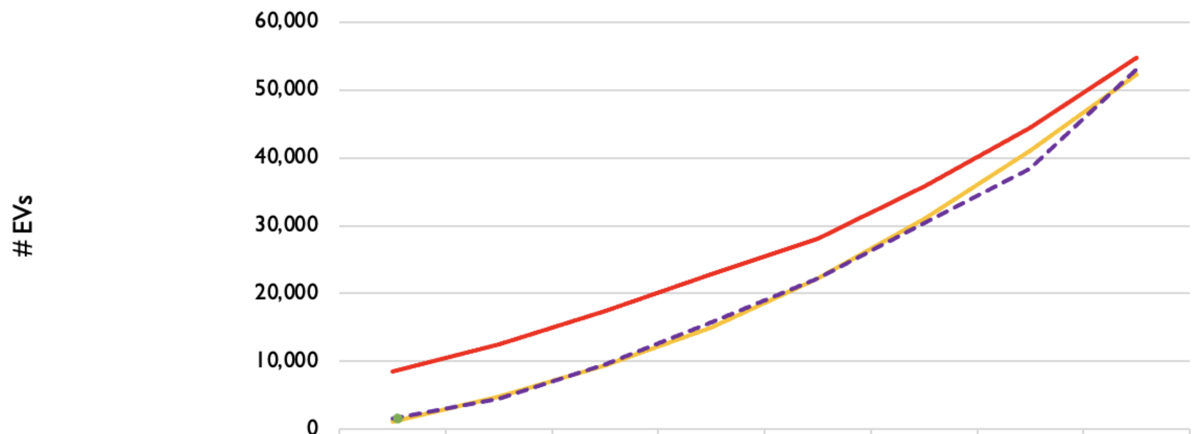
[261] Forecasts provided in Ex. SCE-13, Vol. 7, p. B28 and CEC actual data in Ex. TURN-303. These forecasts include buses and are thus slightly higher than those originally presented in Ex. SCE-02, Vol. 7, and Ex. TURN-07.

[262] Ex. TURN-07E, p. 11.

[263] Id., pp. 12-13.

assumes a significantly smaller EV population than the TEGR.[264]

Figure 4: Comparing Medium- and Heavy-Duty EV Forecasts in SCE Territory[265]



	2023	2024	2025	2026	2027	2028	2029	2030
SCE TEGR Forecast	8,520	12,441	17,497	22,890	28,108	35,809	44,436	54,705
CEC 2022 IEPR AATE 3	1,143	4,801	9,390	15,032	22,210	31,086	41,106	52,294
SCE 2022 Q4 Forecast	1,527	4,527	9,645	15,683	22,264	30,467	38,413	53,024
CEC (Actual)	566							

SCE has also suggested that incremental EV adoption is the critical factor for load growth planning, unlike cumulative adoption, and that SCE's incremental adoption forecast is lower than the latest IEPR updates in future years.[266] First, however, cumulative load and incremental load are both relevant when assessing the need for capacity upgrades. In evidentiary hearings, SCE witness Mr. Esguerra acknowledged that "when we forecast we start off with a starting point year,"[267] and when asked if that starting point affects planning for later years, stated that "it has some effect."[268] Second, incremental vehicle adoption is still misaligned between the TEGR and

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[264] Id., p. 12.

[265] Excluding buses and applying SCE's assumed vehicle share for consistency. Forecasts are provided in Ex. TURN-07-Atch1 (SCE Response to TURN-SCE-006, Q1 and Q4) and CEC data in Ex. TURN-303.

[266] Ex. SCE-13, Vol. 7, pp. 40-41.

[267] Hearing Transcript, Volume 6, May 8, 2024, page 597, lines 5-10 (Esguerra/ SCE).

[268] Hearing Transcript, Volume 6, May 8, 2024, page 601, line 9 (Esguerra/ SCE).

recent IEPR updates. The CEC vehicle population dashboard shows an incremental increase of 402,988 light-duty electric vehicles statewide and 1,395 MDHD electric vehicles statewide between end 2022 and end 2023.[269] The TEGR assumes an incremental increase of 467,129 light-duty and 8,834 MDHD EVs in 2023.[270] Thus, the TEGR presents a 533% higher incremental vehicle forecast for MDHD EVs, and a 16% higher incremental forecast for light-duty EVs in 2023 compared to the actual statewide population changes reported by the CEC.

11.1.1.2 Other Planning Assumptions in the TEGR Are Inaccurate

Besides too-high forecasts of electric vehicle population growth, SCE adopted other modelling assumptions that inflate the load growth from electrification anticipated by the TEGR compared to the 2022 IEPR.[271] These inputs include per-vehicle usage, time of use (load shapes), and the impacts of other demand side resources and load-modifying resources. The TEGR assumed significantly higher average per-vehicle consumption for light-duty and MDHD EVs than the 2022 IEPR and even SCE's own internal 2022 Q4 sales forecast.[272] SCE countered that this is due to different assumptions about the share of battery electric versus plug-in hybrid light-duty EVs, and medium- versus heavy-duty EVs, in the TEGR compared to the 2022 IEPR.[273] However, forecasting an unreasonably large share of high usage vehicles is an assumption that inflates load expectations and further diverges SCE's expectations from reality. The TEGR assumes that just 2% of MDHD EV are medium-duty in 2023, rising to 32% in 2030;

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[269] Ex. TURN-303.

[270] Ex. SCE-13, Vol. 7, p. B28.

[271] The 2023 IEPR public demand files were not released in time to incorporate into intervenor testimony.

[272] Ex. TURN-07, pp. 14-15.

[273] Ex. SCE-13, Vol. 7, pp. 48-49.

the 2022 IEPR assumes that 81% of MDHD EV are medium-duty in 2023, decreasing to 60% in 2030.[274]

The TEGR also relies on load shapes for light-duty and MDHD electric vehicles that differ from the 2022 IEPR.[275] These include less mid-day charging and higher nighttime peaks beginning at 9pm for MDHD vehicles, and moderately more on-peak charging for light-duty EVs.[276] SCE emphasizes that peak coincidence, not simply load shapes, is what determines the need for local capacity upgrades. But as Cal Advocates explains: "This clustering of MDHD EV's which all begin charging at 9pm results in large, local power spikes which can skew forecasting models into calculating far more infrastructure overloads than a more distributed charging profile,"[277] and as NRDC notes, "if enough MDHD trucks accumulate on the same circuit, then MDHD charging itself may become the source of the peak demand on that circuit."[278] Data from SCE's medium- and heavy-duty charging sites to date evidence smoother aggregated load profiles and softer peaks than those assumed by the TEGR.[279]

SCE also neglects to consider the full load-mitigating impacts of other resources. The TEGR assumes the "mid" CEC 2020 IEPR demand scenarios for resources such as solar PV, energy storage, demand response, and time-of-use, with some upward adjustments, while using the "high" scenarios for electrification demand.[280] However, California has seen increasingly

[274] Ex. TURN-302 (SCE Response to TURN-SCE-110, Q9).

[275] Ex. TURN-07E, pp. 16-18.

[276] Ex. CA-08, p. 24.

[277] Ex. CA-08, p. 25.

[278] Ex. NRDC-01E, p. 20.

[279] Ex. TURN-302 (SCE Response to TURN-SCE-110, Q2).

[280] Ex. SCE-13, Vol. 7, pp. 55-57.

high investment in solar and storage, slower than expected population growth, and high electricity rates depressing demand, all of which exert a downward impact on the 2023 IEPR load forecast in contrast with SCE's TEGR assumptions.[281] Further, SCE does not anticipate any future load mitigation impacts from its ongoing investments in Grid Management Systems (GMS) and emerging technologies such as vehicle to grid (V2G) integration.[282]

SCE spent $210.411 million over 2018-2022 on GMS, and forecasts another $258.691 million over 2023-2028, but it has not begun to quantify the potential benefits of this program for mitigating overloads, even though GMS is designed to improve grid performance in a high DER context. The Commission should ensure that programs designed to reduce system strain and avoid other investments demonstrate those capabilities. While SCE explains that it does not consider GMS because the program is set to begin in 2027, outside "the time horizon of our analysis,"[283] SCE stresses throughout its application that the bulk of its TEGR request is based on forecast grid needs in 2027 and 2028.[284] Similarly, SCE explains that is has not assessed vehicle grid integration as part of its planning process, because the technology is too nascent.[285] Yet this technology is sure to become relevant in the later years of SCE's planning, and Senate Bill 676 and D.20-12-029 require consideration of electric vehicle grid integration when dealing with transportation electrification related applications.[286] The utility cannot have it both ways

[281] Ex. TURN-07E, pp. 19-20; Ex. NRDC-01E, p. 13.

[282] Ex. TURN-07E, p. 19.

[283] Ex. SCE-13, Vol. 7, p. 58.

[284] Ex. SCE-13, Vol. 7, p. 73.

[285] Ex. SCE-13, Vol. 7, p. 57.

[286] Ex. TURN-07E, p. 20.

and argue that it should be granted funding for investments based on uncertain future load, without consideration of emergent load-mitigating technologies.

11.1.1.3 Cal Advocates' Testimony Demonstrates SCE's Base Forecast is Also Inflated

SCE's Base Load Growth Forecast refers to the load growth that SCE estimates will occur within its service territory separate from the supplemental electric vehicle load growth that SCE forecasts in the TEGR.[287] Exhibit Cal Advocates-07 identifies many instances where the Base or Baseline forecast for the Distribution Substation Plan and Transmission Substation Plan are inflated, due to its reliance on the 2020 IEPR.[288] TURN's testimony on new customer service connections (Exhibit TURN-08) also identified that SCE overestimates customer growth, which further increases Base load growth expectations.[289] Accordingly, TURN's proposal to authorize the Base load growth forecast, minus the project specific reductions discussed in Section 11.1.5 below, could potentially be too high. This should provide SCE with sufficient flexibility to cover reasonably expected emergent load growth for electric vehicles, even if its Base request does not include transportation forecasts.

11.1.2 The Commission Should Not Authorize Costs Based on SCE's TEGR Load Growth Forecast Due to Misalignment with IEPR

D.18-02-004 established that "the most recent IEPR system-level forecast is the most appropriate source for DER growth scenarios."[290] TURN agrees with this concept as the most

[287] Ex. CA-07, p. 3.

[288] Id. pp. 11-18.

[289] Ex. TURN-08E, p. 1.

[290] D.18-02-004, p. 1

up to date forecast is most likely to be accurate. While SCE has repeatedly claimed that the 2020 IEPR was the most recently available load forecast that it could incorporate in time for its system planning process, SCE used more updated demand inputs throughout all other parts of SCE's GRC testimony.[291] The 2020 CARB Mobile Source Strategy, which SCE used as a vehicle population growth forecast, is an aspirational vision that was not intended for system planning and has diverged from reality each year since its inception.[292] According, TURN originally proposed that SCE revise its load growth forecast using inputs from, or aligned with, the 2022 IPER.

However, SCE's rebuttal testimony makes it clear SCE is unwilling and seemingly unable to, revise its forecast using the most recent data despite the plethora of evidence presented in this proceeding that shows key elements of SCE's TEGR forecast are significantly inflated and cannot be relied upon as a reasonable forecast. As TURN's Expert, Ms. Ashford testified, "…SCE has not demonstrated the reasonableness of costs above the Base" forecast.[293] Just because SCE's planning process involves engineering and local knowledge does not provide cover writ large for any and all requests.[294] Intervenors do not have the ability to repeat SCE's full planning process, nor have they been given all the requisite information to make recommendations in terms of the IEPR; "SCE did not provide intervenors with a complete proposal based on the 2020 IEPR, as its Base request removes transportation-related costs."[295]

[291] Ex. TURN-07E, pp. 11-12, referencing SCE Response to DR TURN-SCE-092, Q2.

[292] Ex. TURN-07E, pp. 7-8

[293] Hearing Transcript, Volume 16, May 22, 2024, page 1529.

[294] Hearing Transcript, Volume 16, May 22, 2024, page 1527.

[295] Hearing Transcript, Volume 16, May 22, 2024, p.1528 (Ashford/ TURN).

As shown above in Sections 11.1.1.1-2 above, the TEGR forecast is not aligned with the most up-to-date data, including the CEC's 2022 and 2023 IEPR in regard to EV forecasts, especially for MD-HD vehicles, peak load, and other key drivers of load growth. Further, the recently released 2023 IEPR shows even lower peak load, slower customer growth and higher solar adoption to offset load growth needs.[296] All of the flaws with SCE's TEGR forecast demonstrate that SCE has not met its burden to affirmatively demonstrate this aspect of its load growth forecast is just and reasonable. This evidentiary burden is entirely the utility's; other parties do not have the burden of proving the unreasonableness of the utility's forecasts or requests, though TURN and Cal Advocates have demonstrated the numerous flaws in the TEGR methodology.[297] Accordingly, the Commission should reject the TEGR and remove the costs from SCE's load growth capital expenditures forecast, a reduction of $1,031 million.

The Commission should not allow itself to be swayed by fear mongering that a failure to grant SCE's full load growth request is necessary to enable the State's energization initiatives. While transportation and building electrification initiatives will increase load, the impact on capital spending has not been substantiated by SCE's TEGR. Further, the Commission does not need to worry that removing the costs associated with SCE's TEGR forecast will leave SCE without sufficient capital to support energization requests. While TURN's proposed forecast is reasonable and should be sufficient to support energization and load growth in SCE's service territory, SB 410 provides the Investor Owned Utilities (IOUs) an additional opportunity to request incremental funding for energization projects in the unlikely event SCE's Base load growth forecast is exhausted prematurely.

[296] Ex. TURN-07E, p. 21.

[297] Ex. TURN-07E, pp. 6-23; Ex. CA-08, pp. 18-33.

11.1.2.1 SB 410 Provides an Alternative Funding Mechanism in the Unlikely Event SCE's GRC Authorized Forecast is Insufficient

Pursuant to Senate Bill 410 (Becker),[298] which was signed into law in 2023, an IOU may request a ratemaking mechanism that will "track costs for energization projects placed in service after January 1, 2024, that exceed the costs included in the electrical corporation's annual authorized revenue requirement for energization, as established in the … [IOUs GRC] or any other proceeding."[299] The interim rate recovery authorized under SB 410 is limited to "energization projects" that enable customers to connect to the electrical distribution grid.[300] The bill defines energization as:

> connecting customers to the electrical distribution grid and establishing adequate electrical distribution capacity or upgrading electrical distribution or transmission capacity to provide electrical service for a new customer, or to provide upgraded electrical service to an existing customer. The determination of adequate electrical distribution capacity includes consideration of future load. "Energization" and "energize" do not include activities related to connecting electrical supply resources.[301]

Accordingly, many of the same project costs included in SCE's load growth forecast BPE would be considered energization projects potentially subject to interim rate recovery under SB 410, if the additional spending incremental to the GRC authorization is necessary.

In rebuttal, SCE opposes Tesla's recommendation to pursue an SB 410 ratemaking mechanism on two counts. The utility argues that, first, being directed to file a request is premature because the funding avenue is intended to cover shortfalls in GRC funding, and

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[298] Senate Bill (SB) 410 (Becker), Stats. 2023, Ch. 394.

[299] Cal. Pub. Util. Code §937(a)(1).

[300] Cal. Pub. Util. Code §937(b)(1).

[301] Cal. Pub. Util. Code §931(b).

second, that the relevant section of the Public Utilities Code is set for repeal in 2027.[302] TURN agrees it would be premature for SCE to file an application to utilize the SB 410 ratemaking mechanism and is not recommending SCE do so. SCE's Base request is adequate to cover likely load growth expenditures, TURN references SB 410 to establish that SCE has an avenue to pursue additional funding if conditions change significantly between now and the end of 2026.

On September 15, 2023, PG&E filed an application in its Test Year 2023 GRC, A.21-06-021, to utilize the SB 410 ratemaking mechanism for incremental costs of energization projects. In its Decision, voted out July 11, 2024, the Commission authorized Pacific Gas and Electric Company (PG&E), "to record and track, in an interim memorandum account, costs for energization projects placed in service after January 1, 2024 that exceed the energization costs included in PG&E's annual revenue requirement authorized in Phase I" of its 2023 GRC.[303] The Decision capped the incremental revenue requirement at $144.310 million for 2024 projects, $91.568 million for 2025 projects, and $99.071 million for 2026 projects corresponding to capital of $975 million in 2024, $618 million in 2025, and $669 million in 2026, or $2,262 million total , … ."[304]

TURN and Cal Advocates' analyses demonstrate that SCE's Base load growth forecast should be sufficient to fund necessary and reasonably forecast load growth projects during the GRC period. However, the SB 410 ratemaking mechanism for incremental energization costs is an alternative recovery mechanism SCE can exercise if necessary. If SCE needs to utilize the SB

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[302] Ex. SCE-13, Vol. 7, pp. 102-104.

[303] D.24-07-008, Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410 (A.21-06-021), p. 2.

[304] D.24-07-008, Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410 (A.21-06-021), p. 2.

410 mechanism, then the Commission should adopt a similar recovery mechanism as it recently authorized for PG&E, a memorandum account,[305] subject to an annual cost cap.[306]

11.1.2.2 The Commission Should Reject NRDC's Two-Way Balancing Account Proposal

In rebuttal testimony, NRDC revised its original recommendation that the Commission authorize SCE to "establish a one-way balancing account for funds authorized to support energization of load growth related infrastructure"[307] to recommending authorization of a two-way balancing account.[308] NRDC states that it is revising its position "to ensure that SCE has enough funds to make necessary upgrades in light of uncertainty that cuts in both directions but with the greater risk stemming from insufficient investment."[309] TURN agrees there is a lot of uncertainty associated with SCE's load growth forecast, however it is unreasonable and unjust to ratepayers to grant the level of flexibility provided by a two-way balancing account.

To TURN's knowledge, a two-way balancing account for such a significant forecast is unprecedented. It is also unnecessary in light of the interim funding mechanism provided under SB 410. In its first Decision implementing SB 410, the commission deemed a memorandum account as appropriate, despite PG&E's request for a balancing account, as addressed above in Section 11.1.2.1. The Commission should not depart for the standard GRC ratemaking

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[305] D.24-07-008, Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410 (A.21-06-021), pp. 40-41.

[306] D.24-07-008, Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410 (A.21-06-021), pp. 50-52 & p. 87-88 FOF #25.

[307] Ex. NRDC-01, p. 26.

[308] Ex. NRDC-03, p. 10.

[309] Id.

mechanism and should authorize a reasonable forecast for SCE for load growth capital expenditures.

11.1.3 The Rate Increases Resulting from SCE's Inflated Load Growth Forecast Will Disproportionately Burden Disadvantaged Customers and Discourage Electrification.

As addressed in Section 4 above, the entirety of SCE's GRC request, including the load growth capital expenditures forecast, represents a nearly 40% increase over March 2023 rates that could raise the typical Hot Climate Zone customer's bill almost $60 each month by January 2028.[310] These rate impacts raise significant concerns for equity, particularly when evaluating customer burden versus benefit, and for incentivizing electric vehicle adoption to reach California's climate targets. As addressed in Exhibits TURN-03 and TURN-07, low-income households who pay a greater share of their income on electricity bills are disproportionately burdened by rate increases.[311] Further, as TURN witness Ashford notes, "A significant portion of SCE's load growth investments are driven by anticipated commercial vehicle fleets, which, besides potentially positive local-level air quality impacts, are less likely to benefit residential customers in the near-term."[312] Ms. Ashford's analysis of SCE's proposals further indicates that only a small number of the fleets SCE's load growth capital expenditures forecast is intended to enable electrification of fleets that provide public benefits, while a majority serve commercial purposes.[313] Accordingly, a significant portion of the infrastructure investments proposed in

[310] See Ex. TURN-02 (Dowdell) for comparison of rate impacts by climate zone.

[311] Ex. TURN-07E, p. 24, referencing Borenstein et al., "Paying for Electricity in California: How Residential Rate Design Impacts Equity and Electrification." Next 10 and the Energy Institute at Haas, University of California, September 2021, p. 5. Available at https://www.next10.org/sites/default/files/2022-09/Next10-paying-for-electricity-final-comp.pdf

[312] Id. at p. 25.

[313] Id.

SCE's load growth testimony will support EV charging by private corporations, but will be paid for by all ratepayers, including residential customers, many of whom are already struggling to afford their electric bills. Section 4.2 above discusses the equity implications of this.

Rate increases also make it more costly to operate electric vehicles and electrify buildings, counterproductively discouraging new customer vehicle adoption and building electrification. As noted in Exhibit TURN-07, "a 2021 study of electric vehicle adoption in California found that an electricity price increase of one cent per kilowatt hour was associated with a two percent decrease in vehicle purchases across different utility territories."[314] In regard to building electrification, Exhibit TURN-304 identifies high electricity prices and low natural gas prices as two of the key reasons why electric heat pump sales are slumping. Exhibit TURN-304 states,

> … residential electricity rates in California are already about twice as high as the national average and still increasing. These high electricity rates make heat pumps and other forms of building electrification much more expensive.[315]

While the Exhibit TURN-304 also identifies high interest rates as a reason heat pump sales are slumping, that factor cannot be addressed by the Commission in this proceeding. The Commission's decision in this proceeding will have a direct impact on SCE's electric rates which will impact how they compare to most SCE customers other residential fuel choice, natural gas.

In responding to TURN's concerns about the rate impacts of the TEGR, SCE discuss the potential for downward pressure on rates from transportation and building electrification. TURN

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[314] Id. at p. 26, referencing Bushnell, J., Muehlegger, E., & Rapson, D. (2021). Do Electricity Prices Affect Electric Vehicle Adoption? UC Office of the President: University of California Institute of Transportation Studies. Available at http://dx.doi.org/10.7922/G29S1PB5 Retrieved from https://escholarship.org/uc/item/5f80503b.

[315] Ex. TURN-304, p. 3.

acknowledges the potential for downward pressure on rates from transportation and other beneficial electrification, but notes "(H)owever, ratepayers will not receive these benefits if the system investments to serve newly incurred load exceed this downward pressure."[316] NRDC also addresses the potential for downward pressure on rates and points to Cal Advocates' Distribution Grid Electrification Model (DGEM) study showing increased electrical load in SCE's service territory could decrease residential rates by $0.02 per kWh by 2035.[317] NRDC neglects to mention the many caveats in Cal Advocate's DGEM study regarding downward pressure on rates. The DGEM study states:[318]

> Achieving this downward pressure on residential electricity rates is contingent upon five key model assumptions. Downward pressure on residential rates might not be achieved if:
>
> 6. EVs mostly charge in the evening, near peak hours (i.e., 6 p.m. to 10 p.m.), which would drive a higher peak load and, therefore, higher upgrade costs.
>
> 7. Electric rates rise to cover additional electrification programs, such as deploying EV chargers.
>
> 8. New feeders and substations are more expensive than the DGEM estimates.
>
> 9. Expected load growth due to electrification does not occur.
>
> 10. Utilities build more infrastructure than is needed or build infrastructure in the wrong locations because upgrade costs will be higher. (Citations omitted)

SCE's TEGR proposal raises concerns under the final category, creating significant risks of building potentially unnecessary infrastructure, or infrastructure in the wrong locations.

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[316] Id. at p. 26.

[317] Ex. NRDC-01, pp. 23-24.

[318] Ex. NRDC-01, pp. 24, FN 39, referencing Public Advocates Office, *Distribution Grid Electrification Model – Study and Report* (2023). See pp. 43-44 for a discussion of the relevant caveats, available at https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf.

The DGEM study goes on to state, "(G)ood forecasting and planning are key parts of achieving this downward pressure on rates. Utility forecasts must be accurate and not lead to infrastructure over-building. If overbuilding occurs, electrification could cause *upward pressure* on rates."[319] This is exactly what TURN is concerned about with SCE's TEGR. In Exhibit TURN-07 and above in Sections 11.1.1, TURN has demonstrated that SCE's TEGR forecast is based on flawed assumptions, is likely to be inaccurate, and lead to distribution grid infrastructure over-building. The potential for downward pressure on rates in the 2030s could be completely wiped out by infrastructure over-building or building in the wrong locations authorized in this GRC. Further, even if the downward pressure does materialize, it may be too late for low and medium-income residential ratepayers who are struggling to afford SCE's rates now. The impacts of the rate increases proposed to support the TEGR however will be felt by SCE's ratepayers as soon as the authorized rates are implemented.

11.1.4 Private Market Parties Claims of Energization Delays are Not Due to SCE's Lack of Capital

The Commission should not be swayed by claims from TeraWatt and the Joint Truck OEMs that the entire TEGR forecast cost (or more, in the case of TeraWatt) should be approved because of energization delays[320] they have experienced, or uncertainties about SCE's ability to provide a firm energization dates.[321] TURN does not dispute that energization timeliness is important, but SCE has failed to establish that more funding will eliminate energization delays.

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[319] DGEM Study & Report, p. 44.
[320] Ex. Terawatt-01E, pp. 19-20.
[321] Ex. Joint Truck OEMs-01, p. 8.

There is a disconnect between party complaints about energization delays and SCE's request. Distribution capacity upgrades take time to build, and no amount of funding is going to address the external issues that have delayed some currently pending energizations projects. In evidentiary hearings, SCE's load growth witness Mr. Esguerra was asked three separate times about the causes of its underspending in 2023 or energization delays; each time he cited pandemic or supply chain concerns, rather than insufficient capital funds.

Specifically regarding underspending in 2023, Mr. Esguerra stated "(A)nd as I mentioned during that time frame, we had the impacts of the pandemic, we had changes in some of our permitting policies, and we had supply chain shortages, which impacted our ability to execute on those load growth projects."[322] Regarding complaints about energization delays, SCE explained there are "a number of factors" that led to complaints of energization delays, including "supply chain delays" and "pandemic restrictions" as "some of the primary factors".[323]

Lastly, when Mr. Esguerra was asked if reallocating any of SCE's underspending for TSP projects in 2023 to those delayed energization projects some parties complained about would have resolved the energization delays, Mr. Esguerra answered, "No, largely because a lot of those projects are multi-year projects. They would have had to have started much earlier."[324] Accordingly, while party complaints and Commission concerns about energization delays are valid, authorizing unnecessarily excessive capital spending is not the solution and cannot address the many factors influencing energization projects that are outside of the utilities', and even the Commission's control. The Commission should not let fear guide its decision here. TURN's

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[322] Hearing Transcript, Volume 6, May 8, 2024, p. 589: 6-10 (Esguerra/ SCE).

[323] Hearing Transcript, Volume 6, May 8, 2024, p. 594: 12-15 10-12 (Esguerra/ SCE).

[324] Hearing Transcript, Volume 6, May 8, 2024, p. 623:10-12 (Esguerra/ SCE).

load growth capital expenditures proposal provides sufficient funding for thoughtful and well-planned load growth projects necessary to support realistic increases in load growth.

11.1.5 TURN's Project Specific Forecast Reductions are Reasonable and Supported by the Record

Besides concerns with SCE's load forecasting and proposed spending based on the TEGR, TURN has identified multiple project-specific costs within the "Base" forecast and other project areas that SCE has not shown to be reasonable.[325] Under the Distribution Substation Plan (DSP), Transmission Substation Plan (TSP), and other load growth spending categories, SCE's forecasts include duplicative or inaccurate cost estimates, lack details on scope of work, or fail to demonstrate an appropriate level of cost-effectiveness for ratepayer funding. As a result, TURN recommends that the Commission authorize a corresponding reduction to SCE's Base request in the test year, in addition to removal of all costs resulting from the TEGR supplemental forecast. Based on TURN's analysis, this amounts to a reduction of $59.818 million over 2023-2025, including $38.184 million in the test year, about 9% of SCE's 2025 request. TURN further finds this test year reduction to be appropriate given the similar (8-10%) project-specific reductions identified in each of the attrition years relative to SCE's revised forecast.

TURN's recommendation is a relatively modest reduction to SCE's non-TEGR requests, given the numerous issues identified in TURN's analysis and in contrast to the significantly higher Base reduction proposed by Cal Advocates.[326] Issues with specific project planning, in combination with SCE's use of outdated forecasting inputs from the 2020 IEPR (as discussed

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325 For discussion, see Ex. TURN-07E, Pages 27-36.

326 Cal Advocates recommends a $82.703 million (54%) reduction to DSP and TSP base costs in the 2025 test year, based on an adjustment to reconcile SCE's base request with the 2022 IEPR system load forecast (Ex. SCE-13, Vol. 7, Table II-11, p. 63).

above),[327] have inflationary impacts on SCE's cost forecasts. Thus, accepting these minimal proposed cuts to SCE's Base, the Commission should find it even more reasonable to deny all of SCE's request based on the TEGR.

11.1.5.1 The DSP Base Forecast Should be Revised

SCE's Distribution Substation Plan (DSP) includes Distribution Circuit Upgrades, DER-related upgrades, New Circuits, and Substations, and comprises about half of SCE's load growth capital expenditures forecast.[328] SCE's rebuttal position identifies capital expenditures of $231.375 million for DSP in the test year, including $77.659 million for TEGR and $153.717 million for Base projects.[329] SCE spent 35.5% ($59 million) less than it was authorized for DSP projects in the 2021 test year.[330] In evidentiary hearings, SCE highlighted that it recorded more than it forecast in 2023 for DSP projects;[331] but excluding carryover costs from projects in prior years that were not included in SCE's 2025 test year GRC application, SCE actually spent 8% ($2.939 million) less than it forecast for DSP projects.[332]

TURN has recommended two reductions to SCE's DSP request. First, TURN removes costs associated with the DSP Substation Project PIN 8043 (increasing capacity of the Garnet 115/33kV Substation) from its recommendation, because SCE was previously authorized

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[327] SCE prepared its base forecast by disaggregating the CEC's 2020 IEPR forecast, in combination with local engineering knowledge (Ex. SCE-13, Vol. 7, Page 64).

[328] Ex. SCE-02, Vol. 7, p. 69.

[329] SCE's recommendations are summarized in Ex. SCE-13, Vol. 7, Table II-6, p. 7, and Table II-7, p. 9.

[330] Ex. SCE-02, Vol. 7, p. 14.

[331] Hearing Transcript, Volume 6, May 8, 2024, p. 622 (Esguerra/ SCE).

[332] Not including emergent projects ($214,863) and carryover costs for projects from prior years ($10.407 million). Ex. TURN-300, SCE Response to Data Request TURN-SCE-104.

funding for this project in the 2021 GRC to meet an in-service date of November 2021.[333] SCE forecast $9.830 million for the project over 2023-2024,[334] and recorded spending $9.647 million in 2023.[335] SCE contends that the project's delay was due to unforeseen electrical and civil work, that it had jurisdiction to reprioritize those funds elsewhere, and that the project should still be entered into the permanent rate base once in service.[336] While this project may be eligible for future recovery, there must be a limitation on duplicative authorizations for the same capital expenditures in subsequent rate cases. Customers should not be expected to repeatedly shoulder the same costs while SCE exhibits a trend of over-forecasting and underspending on DSP projects, reprioritizing funds to other investment areas, and later suggesting that load growth capital forecasts have been insufficient to complete distribution system upgrades to fulfill energization requests in a timely manner.[337]

Second, TURN opposes SCE's request for DSP DER capital expenditures because of the way in which SCE has estimated costs for the procurement of energy storage devices.[338] SCE requests $10 million in 2025, and $119.633 million over the 2023-2028 period for this project area.[339] While TURN is generally supportive of temporary and relocatable alternatives to traditional grid investments to meet new load, utilities should make these investments at least cost feasible to ratepayers. Based on cost estimates provided by SCE, renting rather than

[333] Ex. TURN-07E, p. 28.

[334] Ex. SCE-13, Vol. 7, p. 74.

[335] Ex. TURN-300, SCE Response to Data Request TURN-SCE-104.

[336] Ex. SCE-13, Vol. 7, p. 75.

[337] Hearing Transcript, Volume 6, May 8, 2024, p. 588: 23-34 (Esguerra/ SCE).

[338] Ex. TURN-07E, pp. 29-30.

[339] Ex. SCE-02, Vol. 7, p. 48.

purchasing would provide a savings to ratepayers if energy storage devices are in use for fewer than four months each year, or continuously over five or fewer years.[340]

The utility cannot argue it both ways, as it seems to do in rebuttal.[341] If these devices are short-term, "stop-gap"[342] measures that do not defer traditional wires solutions, then they are strong candidates for leasing or renting. If these devices are long-lasting investments that should provide value to ratepayers for the entirety of their service lives, then SCE should demonstrate that value. As highlighted by Cal Advocates, SCE has yet to identify locations for future deployment of these mobile units.[343] Lacking these details, at a minimum, the utility should be able to quantify the costs to "transport, interconnect, monitor, maintain, and disconnect" devices to compare the full ownership expenses with alternative operating models.[344] The utility's potential for capital returns and a 30% Investment Tax Credit benefit[345] should not motivate procurement over more affordable options, at ratepayers' expense.

Given these uncertainties, TURN removes the DSP DER cost forecast from its cost recommendations. The Commission should direct SCE to perform a cost-benefit analysis of ratepayer spending for distributed energy resources, including energy storage devices and mobile substations when data becomes available. A memorandum account with specific parameters regarding the types of costs that can be recorded in it, may be a better mechanism to record these costs, given the urgency of these investments to meet demand in the short-term and mitigate

[340] Ex. TURN-07E, p. 30.

[341] Ex. SCE-13, Vol. 7, pp. 92-93.

[342] Ex. TURN-Atch1 (SCE Response to DR TURN-SCE-050, Q10.a-b).

[343] Ex. CA-07, p. 13.

[344] Ex. TURN-Atch1 (SCE Response to DR TURN-SCE-050, Q10.a-b).

[345] Ex. TURN-07E, p. 27, as first mentioned in SCE Response to DR TURN-SCE-079, Question 1b.

potentially misplaced traditional infrastructure investments, if costs are shown to be reasonable for ratepayers.

11.1.5.2 The DER-Driven Grid Reinforcement Memorandum Account Should be Closed

Prior to filing its GRC application, SCE had not recorded any costs to the DER-driven grid reinforcement (DER-DGRPMA) memorandum account, which it was authorized to establish in the 2021 GRC decision.[346] SCE has not forecast any related capital expenditures for this GRC period and has also failed to demonstrate any progress towards performing a grid reinforcement needs analysis to identify potential projects as part of its distribution planning process.[347] Accordingly, TURN recommended that the Commission close the DER-DGRPMA memorandum account.[348] The utility has since recorded $0.197 million to the memorandum account, which SCE claims is "demonstrating that SCE is doing work in this area." [349] However, utilization of the memorandum account alone does not demonstrate that SCE has made progress in developing specific software and analytical processes. Therefore, TURN continues to recommend eliminating the memorandum account unless and until SCE has made progress in its tool development. SCE is requesting funding for the same types of distribution projects (circuit upgrades, new circuits etc.,) that it considers appropriate for this account[350] through its Distribution Substation Plan and can also make use of DER-specific funding avenues such as an account pursuant to SB 410 if the need arises. Should the Commission decide to retain the memo

[346] D.21-08-036, p. 653.

[347] Ex. SCE-2 Vol. 7, p. 66.

[348] Ex. TURN-07, p. 31.

[349] Ex. SCE-18, Vol. 1, pp. 25-26.

[350] Ex. SCE-2 Vol. 7, pp. 67-69.

account, it should direct that recorded costs may only be found reasonable for rate recovery if they make use of a DER-driven needs analysis that is conducted as part of SCE's distribution planning process.

11.1.5.3 The Transmission Substation Plan (TSP) Base Forecast Should be Revised

SCE's Transmission Substation Plan (TSP) includes the Subtransmission Lines, A-Bank, and Subtransmission VAR Plans, and comprises about a third of SCE's load growth capital expenditures forecast.[351] SCE's rebuttal position identifies capital expenditures of $143.991 million for TSP in the test year, including $89.709 million for TEGR and $54.282 million for Base projects.[352] Similar to the DSP, SCE has exhibited notable work setbacks and underspending in this project area in recent years. While the utility overspent on TSP projects in its 2021 test year, this was due to exceptional costs associated with sporting events; SCE shares that overall, TSP projects were delayed relative to expectations due to environmental review holdups and supply chain issues.[353] In 2023, SCE spent $49.6 million, or 85%, less than it forecast in 2023 for TSP projects (91% less than forecast excluding carryover costs for prior year projects).

TURN recommends a reduction of SCE's request due to the cancellation of a planned A-Bank substation, TSPABank35796 (Rector), of $8.442 million in the test year, with forecast costs of $40.262 million over the 2023 to 2028 period.[354] SCE suggests that because there was

[351] Ex. SCE-02, Vol. 7, p. 69.

[352] SCE's recommendations are summarized in Ex. SCE-13, Vol. 7, Table II-6, p. 7, and Table II-7, p. 9.

[353] Ex. SCE-02, Vol. 7, p. 14.

[354] Ex. TURN-07, p. 32.

an anticipated need for TSPABank35796 (Rector) at the point in time when its forecast was developed, and because smaller upgrade projects may be needed to take the project's place, funding is reasonable even though the project has been found unnecessary.[355] TURN objects to SCE's arguments on multiple grounds.

As an intervenor, TURN makes recommendations based on the best information available over the course of this proceeding and does not have complete insight into which resources SCE may have had access to at a given time. It is simply unreasonable to authorize substantial funding for a large capital project that will not be carried out, particularly in an area of capital expenditures where SCE has historically underspent relative to its forecast due to external and internal obstacles. This is particularly true given that seven of the twelve proposed A-Bank projects in SCE's request are awaiting licensing and marked as "under review".[356] Considering the size of this funding request, it is further illogical to authorize funding on the assumption that un-scoped and unplanned smaller projects will arise in its place, with similar overall costs. While imprecision may be an inevitable aspect of forecast based ratemaking, it should not be considered a preferred ideal.

SCE has not shown that the costs of its new proposed climate-driven circuit ties program are reasonable, and the full request for this initiative should be denied.[357] The program includes $19.714 in test year capital expenditures and a forecast of $80.03 million from 2025 to 2028, which will support nine identified projects and four to eight projects that have not yet been scoped. TURN and Cal Advocates agree that SCE should not be authorized the $6.3 million

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[355] Ex. SCE-13, Vol. 7, p. 79.

[356] Including environmental review, per Ex. SCE-02 Vol. 7, p. 81E.

[357] Ex. TURN-07, pp. 34-36.

(32%) of its request in the test year for these undefined projects.[358] The wide range in project costs ($1.9 to $13.4 million), uncertain number of additional projects, and newness of this program area are all causes for concern. While SCE has since identified an additional two projects, their costs also vary significantly ($0.701 million and $5.258 million).[359]

Further, TURN found that for all proposed projects, SCE has failed to evidence good value for ratepayer money. SCE contends that Risk Spend Efficiency scores (RSEs) and cost-benefit ratios are not required for all risk mitigation decisions, and that the CAVA proved the necessity of these investments.[360] In the absence of a metric such as an RSE, the utility should still demonstrate the cost-worthiness of a given investment for recovery through rates. The information provided by SCE fails to meet this standard; project costs range from $163 to $11,445 per potentially impacted customer.[361] Furthermore, SCE's claim that "the quantitative analysis in CAVA"[362] proves the necessity of a climate ties program does not comport with a response to TURN that "SCE did not perform quantitative evaluation of impacts on customers from the alternatives to climate-driven circuit ties."[363] While the CAVA identified future risks, this specific program's value cannot be determined without a thorough evaluation of alternatives such as vegetation management, fire wrapping poles, replacing pad mounted switches with submersible equivalents, and no mitigation, which includes the costs for emergency response

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[358] Ex. CA-7, p. 21 and TURN-07, p. 34.

[359] Ex. SCE-13, Vol. 7, p. 97.

[360] Ex. SCE-13, Vol. 7, pp. 100-102.

[361] Ex. TURN-07-Atch1 (SCE Response to DR TURN-SCE-050, Q21, "TURN-SCE-050 Q21a-c 240122_Nine_Identified_Projects.xlsx") and Ex. SCE-13, Vol. 7, p. 97.

[362] Ex. SCE-13, Vol. 7, p. 99.

[363] Ex. TURN-07-Atch1 (SCE Response to DR TURN-SCE-006, Q18).

crews to re-energize customers in the aftermath of climate events.[364] As Ms. Ashford testified: "risk reduction activities are potentially infinite, and ratepayer funds are not."[365] TURN maintains its recommendation that SCE's request for this untested program be denied, and at a minimum, no costs authorized for the projects labelled "unplanned" in its application.

11.2 Transmission Projects

11.3 Engineering O&M

12. NEW SERVICE CONNECTIONS AND CUSTOMER REQUESTED SYSTEM MODIFICATIONS

12.1 New Service Connections

SCE's GRC forecast includes capital expenditures associated with new service connections work for each customer class or load type. SCE bases these capital forecasts on its forecast of new meter sets.[366] SCE uses the terms "new meters" and "gross meters" interchangeably in its testimony, as does TURN here.[367] To derive the capital expenditures forecast, SCE multiplied the gross meter set forecast for each customer class by the 2018-2022 five-year average recorded unit cost for that class.[368]

TURN recommends lower gross meter set forecasts for the residential, commercial, and agricultural customer classes, and therefore, lower capital forecasts, as explained in TURN's testimony and summarized below. As explained below, TURN also accepts SCE's unit cost

[364] Ex. TURN-07, p. 35.

[365] Ex. TURN-07, p. 35.

[366] Ex. SCE-02V08, p. 5 (referring to the gross meter set forecasts presented in Ex. SCE-07V01, Section IV.B.2).

[367] Ex. TURN-400 (SCE Response to TURN DR 124), p. 8.

[368] Ex. SCE-02V08, p. 13 (residential capital expenditures); p. 20 (commercial capital expenditures); p. 25 (agricultural capital expenditures).

forecasts for each customer class, so the only difference between TURN's position and SCE's is the number of gross meter sets.

TURN withdraws some of its recommendations following consideration of SCE's rebuttal testimony. TURN highlights these changes here before addressing TURN's current recommendations.

First, TURN originally proposed to change the escalation rates used to forecast residential meter set unit costs. TURN assumed a 2.5% inflation rate starting in 2023, whereas SCE applied the same escalation rates used throughout its GRC testimony.[369] TURN withdraws this recommendation. TURN now recommends that historical costs be escalated to test year 2025 dollars using standard escalation, consistent with SCE's position. Because TURN recommends that attrition year capital costs be determined pursuant to the post-test year mechanism adopted by the Commission in this GRC, escalation to post-test year dollars will flow from that mechanism.[370]

Second, TURN originally proposed the creation of a new one-way balancing account for new connections costs but withdraws that recommendation.[371]

Finally, TURN withdraws the following procedural recommendations regarding SCE's showing in the next GRC: (1) the Commission should direct SCE to provide in its testimony (a) any alternative models and variables it considered in its forecast model selection process; and (b) a quantification of the historical accuracy of the forecast methodology it proposes; and (2)

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[369] Ex. TURN-08 (McGovern), pp. 20-21.

[370] Ex. TURN-17 (Yap), p. 2 (recommending a standard capital attrition mechanism for all cost categories other than wildfire mitigation capital).

[371] Ex. TURN-08 (McGovern), pp. 3, 29.

prohibit SCE from using data that has been demonstrated to be repeatedly biased.[372] TURN no longer recommends that the Commission take these specific actions.

The following tables compare TURN's and SCE's gross meter set 2025-2028 forecasts and associated capital expenditures forecasts for Test Year 2025. TURN focuses on Test Year 2025 because no party has proposed budget based attrition for new connections capital expenditures in this GRC.

Residential - New Meter Connections				
	2025	2026	2027	2028
SCE	33,421	36,084	36,768	36,154
TURN	32,569	32,799	33,031	33,265
TURN-SCE	(852)	(3,285)	(3,737)	(2,889)
Commercial - New Meter Connections				
	2025	2026	2027	2028
SCE	3,918	3,918	3,918	3,918
TURN	2,582	2,383	2,200	2,031
TURN-SCE	(1,336)	(1,535)	(1,718)	(1,887)
Agricultural - New Meter Connections				
	2025	2026	2027	2028
SCE	184	184	184	184
TURN	102	89	79	69
TURN-SCE	(82)	(95)	(105)	(115)

[372] Ex. TURN-08 (McGovern), pp. 3-4. TURN continues to recommend that the Commission require SCE to provide all raw data for its customers and meter forecast models in its workpapers supporting direct testimony, as explained below.

New Connections Capital Expenditures - Nominal ($000)				
Item	Residential 2025	Commercial 2025	Agricultural 2025	Formula
SCE Meter Sets	33,421	3,918	184	(a)
TURN Meter Sets	32,569	2,582	102	(b)
SCE Unit Cost	$4.202	$31.098	$28.586	(c)
SCE Total Cost**	$141,863	$134,697	$5,354	(d)
TURN Reduction	$3,580	$41,547	$2,344	[(a-b)*c]
TURN Total Cost	$138,283	$93,150	$3,010	(d) - [(a-b)*c]
** Ex. SCE-13V08, Tables II-3, II-4, II-5.				

12.1.1 The Commission Should Adopt TURN's Residential Gross Meter Set Forecast for the Test Year.

12.1.1.1 SCE's Residential Gross Meter Set Forecast is Flawed Because It Relies on an Overly Optimistic Housing Forecast and Underperforming Historical Regression Models.

There are two major components to SCE's residential meter forecast: (1) the historical regression model that projects the residential meter forecast into 2023-2028, and (2) the forecast housing data input into the extended model.[373] The same is true for SCE's residential customer forecast.[374] The main forecasted explanatory variable for both the residential new meter model and customer model is the average of January 2023 housing start forecast data provided by Moody's and S&P Global Market Intelligence (formerly IHS Markit and before that, Global Insight).[375] According to SCE, "residential new meter installation activities are closely tied to activities in the residential construction sector, with lags of up to 12 months."[376] SCE relied

[373] Ex. TURN-08 (McGovern), p. 8.

[374] Ex. TURN-08 (McGovern), p. 8.

[375] Ex. SCE-02V08, p. 5; Ex. SCE-07V01, p. 99. SCE provides historical and forecast housing starts in Figure VI-4 on p. 91.

[376] Ex. SCE-07V01, p. 98.

exclusively on Moody's housing start forecast in the 2021 GRC but used an average here to provide a more conservative approach.[377] SCE explains that Moody's "predicts a more aggressive growth in the expansion of construction activities and the housing market," while S&P Global Market Intelligence "anticipates gradual to flat growth in the housing market."[378] TURN demonstrates in testimony the weaknesses in both the regression model and the housing forecast relied on by SCE, summarized here.

SCE produces customer regression models for individual counties in its service territory, which are used to generate county-specific residential customer forecasts.[379] The customer regressions are the first step in generating SCE's forecasts; they attempt to quantify a historical relationship between the monthly customer growth and various seasonal and economic factors including housing.[380] SCE then totals the individual forecasts for a residential customer forecast.[381] SCE's individual residential customer regression models have varying levels of accuracy, between 58.5% and 89.4% explanatory power, and therefore the resulting aggregate residential customer regression model has mediocre explanatory power.[382] As TURN explains in its testimony, SCE's "regression results, which explain the relationship between housing starts and new residential customers, are often off, even if all the data is perfectly accurate."[383] In addition, TURN pointed out that in the Santa Barbara/Ventura customer forecast model, the

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[377] Ex. SCE-02V08, p. 5.

[378] Ex. SCE-02V08, p. 5.

[379] Ex. TURN-08 (McGovern), p. 4.

[380] Ex. TURN-08, (McGovern), p. 6.

[381] Ex. TURN-08 (McGovern), p. 4.

[382] Ex. TURN-08 (McGovern), p. 4; Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1).

[383] Ex. TURN-08 (McGovern), p. 4.

housing starts are not even statistically significant, raising the question of whether housing starts are relevant to the forecast of residential customers in that region at all.[384]

Beyond the shortcomings in SCE's regression models, SCE's forecasts are heavily impacted by the housing start forecasts it relies on. As noted above, SCE uses a blend of the proprietary, confidential housing start forecasts provided by two third party vendors: Moody's and S&P Global Intelligence. These vendors' forecasts in other GRCs have been overly optimistic. SCE has relied on Moody's housing start forecasts in multiple GRCs.[385] In the 2021 GRC, the Commission recognized that Moody's forecasts have repeatedly been high.[386] In this GRC, TURN showed that Moody's housing start forecasts from the 2021 GRC were also much higher than actual housing starts from 2019 through 2022.[387] SCE has not used housing start forecasts from S&P Global Intelligence in recent GRCs, but TURN pointed to its analysis in the still-pending SDG&E 2024 GRC, where TURN demonstrated that its forecasts have also shown upward bias.[388] SDG&E used housing forecasts from both S&P Global Intelligence (then called IHS Markit) and Moody's in its customer connections forecast.[389]

[384] Ex. TURN-08 (McGovern), p. 4.

[385] D.21-08-036, pp. 142-144.

[386] D.21-08-036, pp. 143-144.

[387] Ex. TURN-08 (McGovern), pp. 9-10 (comparing SCE's housing starts forecast in the 2021 GRC for 2019-2022 in Figure 7 to recorded housing starts for those years in Figure 8).

[388] Ex. TURN-08 (McGovern), p. 24;

[389] Ex. TURN-08 (McGovern), p. 11, fn. 27.

TURN's observations regarding SCE's model made TURN cautious about using SCE's model in this GRC.[390] TURN therefore developed an alternative methodology that does not rely on SCE's model.[391]

12.1.1.2 TURN Recommends an Alternative Forecast Based Entirely on Historical Recorded Data to Promote Transparency and Eliminate the Risk of Bias.

TURN recommends a forecast of residential new meters based on the most recent 10-year average growth rate in meters, not based on housing forecasts.[392] TURN bases its forecast on historical data instead of proprietary third party, confidential data, as forecasts based on recent history are unbiased, relevant, transparent, and verifiable.[393] TURN calculates the meter growth rate by comparing the number of new meters added in one year to the total number of residential meters at the end of the prior year.[394] For example, the growth rate for 2022 would be calculated as follows (based on SCE's recorded data):

Gross Meters in 2022 / Total 2021 Year-End Residential Meters = Growth Rate
31,201 Gross Meters / 4,502,538 Existing Meters = 0.69% 2022 Growth Rate

[390] Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1).

[391] Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1).

[392] Ex. TURN-08 (McGovern), p. 11.

[393] Ex. TURN-08 (McGovern), p. 2.

[394] Ex. SCE-18V01, Appendix A, pp. A44-A45 (SCE-TURN-005, Q4-Q5).

As TURN explained in response to a data request from SCE, TURN decided to use a 10-year historical average growth rate to forecast new meters and customers for several reasons.[395] As a general matter, historical averages are routinely used by utilities to forecast future work and costs in GRCs, particularly where historical values have fluctuated up and down overtime.[396] Using an average will capture that historical variation. Historical averages also rely on transparent, recorded data, thus avoiding the complexity inherent in utility models that rely on proprietary third party data. In this case, TURN noticed that beginning in 2017, the growth rate of residential meters in the SCE's service territory began to stabilize and then drop, and therefore determined that projecting increasing rates of growth beyond historical growth rates would be inappropriate.[397] TURN's witness additionally explained:

> Further, history demonstrates that approximately once every 10 years in the US, a recession occurs. Therefore, a period shorter than 10 years may disproportionally emphasize higher or lower growth years. For instance, a 5-year average that picked up a recession would give recessionary impacts more weight than statistically appropriate, and the same would be true for a 5-year average without a recession. On the other hand, a longer historical period, such as 20 years, will pick up conditions that are no longer relevant, like earlier norms and public policies regarding housing development, density, building codes, and zoning. For an activity driven by econometric forces outside of the company's control, like customer growth, a relatively contemporary historical period like 10-years reasonably captures fluctuations and upward/downward trends without relying on outdated (or less relevant) earlier time periods.[398]

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[395] Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1).

[396] *See* D.04-07-022 (SCE 2003 GRC), pp. 15-16 ("For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typical four years) is a reasonable base expense for the [] test year.").

[397] Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1).

[398] Ex. SCE-18V01, Appendix A, pp. A42-A43 (SCE-TURN-005, Q1). Dr. McGovern has a B.A. in Math and Economics and a Master of Science and PhD in Economics. (Ex. TURN-08-Atch1, Statement of Qualifications of Dr. Jaime McGovern).

TURN originally calculated the 10-year average growth rate for 2013-2022, which equals 0.68%.[399] In rebuttal testimony, SCE argued that TURN's forecast for residential new meters, as well as residential customers, "must be increased to reflect SCE's actual 2023 residential customer counts data."[400] In 2023, SCE recorded 33,668 residential new meter connections and a total of 4,574,337 residential meters at year-end, as well as 4,578,185 residential customers.[401] TURN accepts SCE's recommended modification and has updated its 10-year average growth rate to include years 2014-2023. As the figure below shows, this update increases the 10-year average growth rate for new meter connections from 0.683% to 0.707%.[402]

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[399] Ex. TURN-08 (McGovern), p. 14; Ex. SCE-18V01, p. 82.

[400] Ex. SCE-18V01E, p. 82 (2023 recorded residential new meter connections and customers); Appendix B, p. B108E (2023 recorded residential new meter connections and 2023 year-end recorded residential total meters).

[401] Ex. SCE-18V01, p. 82.

[402] Calculation: 2013 New Connections / 2012 Total Meters = 2013 % Meter Growth. SCE provides these same calculations in Ex. SCE-18V01E, p. B108E.

Residential Meters - Updated Growth Rate			
Year	**Total Meters**	**New Connections**	**% Meter Growth**
2012	4,318,366		
2013	4,340,206	21,840	0.506%
2014	4,364,839	24,339	0.561%
2015	4,389,286	26,423	0.605%
2016	4,416,513	32,231	0.734%
2017	4,445,176	34,489	0.781%
2018	4,474,407	34,759	0.782%
2019	4,503,097	34,685	0.775%
2020	4,535,250	32,828	0.729%
2021	4,502,538	30,143	0.665%
2022	4,542,098	31,201	0.693%
2023	4,574,337	33,668	0.741%
2013-2022 Average Growth Rate			**0.683%**
2014-2023 Average Growth Rate			**0.707%**

As a result of updating the 10-year average growth rate to 0.707%, TURN's forecast of test year 2025 residential new meter connections is 32,569. The following figure shows the derivation of this updated forecast.[403]

Residential Meters - Updated Test Year 2025 Forecast			
Year	**Total Meters**	**New Connections**	**% Meter Growth**
2023R	4,574,337	33,668	0.741%
2014-2023 Average Growth Rate			0.707%
2024F	4,606,678	32,341	0.707%
2025F		**32,569**	0.707%

[403] Calculation: 2023 Recorded Total Meters * 2014-2023 Average Growth Rate = 2024 Forecast New Connections. 2024 Forecast Total Meters = 2023 Recorded Meters + 2024 Forecast New Connections. 2024 Forecast Total Meters * 2014-2023 Average Growth Rate = 2025 Forecast New Connections.

As shown in TURN's testimony, TURN's original forecast, which applied the 2013-2022 average growth rate of 0.68% to forecast 2023-2028 residential new meter connections, produced a lower 2025 forecast of 31,452.[404] Of note, TURN's updated methodology produces a 2025 forecast that is almost identical to the 5-yr average of 2019-2023 recorded new meter connections (32,505), which is the methodology SCE uses for commercial and agricultural meters.[405] TURN also provides attrition year new connections forecasts using this updated 10-year average meter growth rate for illustrative purposes, while noting that no party has proposed budget-based capital attrition adjustments for new connections capital.

TURN Forecast of Residential New Connections (Updated)	
Year	**New Connections**
2025F	32,569
2026F	32,799
2027F	33,031
2028F	33,265

12.1.1.3 SCE's Criticisms of TURN's Approach Are Misplaced.

SCE argues that TURN's new meter connections forecast "is based on a flawed methodology" because TURN compares the number of new meter connections added in one year to the number of existing meters at the end of the prior year to determine the growth rate.[406] SCE asserts that the average annual growth rate should instead be calculated to capture the year-over-year change in the number of new meter connections and illustrates its alternative "growth rate"

[404] Ex. TURN-08 (McGovern), p. 15, Figure 12.

[405] Calculation: (34,685 + 32,828 + 30,143 + 31,201 + 33,668) / 5 = 32,505.

[406] Ex. SCE-18V01, p. 81.

calculation in its rebuttal testimony.[407] SCE's growth rate provides the proportional change from year to year in the number of new residential meter connections, expressed as a comparison between the number of gross meters added in the current year to the number of gross meters added in the prior year. For example, SCE calculates a growth rate of 11.44% for 2014, which reflects how the number of new meters in 2014 compares to the number of new meters in 2013 (it is 11.44% higher than the 2013 new meters), without regard to the total number of meters.[408] SCE's calculated annual growth rates vary widely over the 2014-2023 time period, ranging from a high of 21.98% in 2016 to a low of -8.18% in 2021.[409]

SCE's approach provides a less useful perspective than TURN's because it tracks volatility, not the absolute volume of new meter connections. As shown in the figure above ("Residential Meters – Updated Growth Rate"), the years in the 2013-2023 time period with by far the highest numbers of new meter connections are 2017, 2018, and 2019 (with 34,489, 34,759, and 34,685 new meter connections, respectively). TURN's growth rate methodology likewise recognizes those three years as having the highest three growth rates in the 2013-2023 time period (with 0.781%, 0.782%, and 0.775%, respectively). In contrast, SCE's methodology assigns those three years growth rates of 7.01%, 0.78%, and -0.21%. Moreover, SCE's highest growth rate, 21.98%, belongs to a year with 32,231 new meters (2016), which is fewer new meters than recorded in 2017, 2018, 2019, 2020, and 2023. SCE's second highest growth rate, 11.44%, is for 2014, which had the lowest number of new meter connections, 24,339, among the years for which SCE calculated its growth rate. TURN submits that SCE's growth rate

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[407] Ex. SCE-18V01, p. 81 (referring to Appendix B (Average Growth Rate from 2013-2022)).

[408] Ex. TURN-400 (TURN-SCE-124), Q4.

[409] Ex. SCE-18V01E, Appendix B, p. B108E.

methodology, while interesting, does not produce a meaningful 10-year average growth rate for use in forecasting the level of new meter connections in this GRC.

SCE also criticizes TURN for using a denominator in its growth rate calculations -- the year-end total active residential meter count -- that captures changes in the number of meters from circumstances other than simply new customer connections, such as retirements, replacements, and temporary meter installations.[410] When TURN asked SCE to provide data that would enable TURN to isolate the impacts of retirements, replacements, and temporary meters on total year-end meters, SCE was unable to provide sufficient information to enable TURN to adjust its calculations.[411] In any case, the recorded change in year-end total active residential meters from 2012-2023 was equal to or smaller than the number of new meter connections in all but two years, 2014 and 2022, as shown in the table below.[412]

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[410] Ex. SCE-18V01, pp. 81-82.

[411] Ex. TURN-400 (TURN-SCE-124), Q1.

[412] "Total Meters" and "New Connections" come from Ex. SCE-18V01E, Appendix B, p. B108E. "Change in Total Meters" = difference between Total Meters in one year and the prior year. "Difference" = "New Connections" – "Change in Total Meters," such that a negative "Difference" indicates that there were fewer New Connections in that year than the Change in Total Meters.

Annual Change in Total Meters vs. New Connections				
Year	Total Meters	Change in Total Meters	New Connections	Difference
2012	4,318,366			
2013	4,340,206	21,840	21,840	-
2014	4,364,839	24,633	24,339	(294)
2015	4,389,286	24,447	26,423	1,976
2016	4,416,513	27,227	32,231	5,004
2017	4,445,176	28,663	34,489	5,826
2018	4,474,407	29,231	34,759	5,528
2019	4,503,097	28,690	34,685	5,995
2020	4,535,250	32,153	32,828	675
2021	4,502,538	(32,712)	30,143	62,855
2022	4,542,098	39,560	31,201	(8,359)
2023	4,574,337	32,239	33,668	1,429

This means that TURN's methodology has a generous bias resulting from this imprecision. TURN's methodology applies the 10-year average growth rate to 2023 recorded year-end total meters to produce a forecast of 2024 new meter connections, and then adds the 2024 new meter connections to 2023 recorded total meters to produce the forecast of 2024 total meters. That forecast of 2024 total meters is likely generous given historical trends, but TURN nonetheless uses it to generate the forecast of 2025 new meter connections.

And as shown above, TURN's growth rate calculations provide a logical approach to capturing the relative level of new connections each year. The Commission should reject SCE's contention that TURN's calculation is fundamentally flawed and produces "meaningless" results.[413]

[413] Ex. SCE-18V01, p. 82.

12.1.1.4 The Commission Should Direct SCE to Use Forecasted Housing Completions Rather than Housing Starts in its Models in the Next GRC if SCE Elects to Base Its Customer and New Meter Forecasts on Housing Once Again.

SCE's asserts that "a change in the number of new meter connections or new customers is typically a result of a change in the number of housing starts that occurred up to 12 months earlier."[414] As a result, SCE's residential customer models "are constructed on the basis that new customers are determined primarily by housing starts (with a lag extending from zero up to 24 months depending on the region)."[415]

TURN recommended in testimony that SCE should use housing completion data, rather than lagged housing starts, if it continues to forecast customers and new connections based primarily on housing.[416] The use of housing completion data as a residential meter and residential customer forecast input would have two impacts. It would (1) eliminate the need for lagged variables which would permit analysis by a greater range of software packages, and (2) reduce the error introduced by the lagged variable when housing is completed either quicker or more slowly than the specified lag.[417] Additionally, TURN notes that SDG&E made this switch in its 2024 GRC because, as SDG&E explained to TURN, "[u]sing housing completions, which is closely related to electric customer gains, allows SDG&E to eliminate the need to use a lagged housing start variable in its model."[418]

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[414] Ex. SCE-07V01 WP Bk. A, p. 167.

[415] Ex. SCE-07V01 WP Bk. A, p. 167.

[416] Ex. TURN-08 (McGovern), p. 11.

[417] Ex. TURN-08 (McGovern), p. 12.

[418] Ex. SCE-18V01, Appendix A, p. A46 (SCE-TURN-005, Q8).

In rebuttal testimony, SCE questioned whether TURN's suggestion would have a material impact on SCE's forecasts. But SCE expressed a willingness to "explore the impact of using housing completion as an alternative explanatory variable in SCE's customer and new meter forecast models in its next GRC cycle."[419]

The Commission should accordingly direct SCE to including housing completion in its models in the next GRC (if relevant to SCE's chosen forecast methodology in that case). TURN understands that SCE may also choose to present an additional forecast based on housing starts. Even if SCE ultimately recommends a forecast based on housing starts, having the comparison will be instructive as parties evaluate SCE's forecast methodology and consider future refinements.

12.1.2 The Commission Should Adopt TURN's Commercial Gross Meter Set Forecast for the Test Year.

SCE describes its commercial gross meter forecast methodology as using "a simple linear trend projection leveraging most recent installation history as well as data and knowledge from SCE's local planning and operation organizations."[420] SCE elsewhere suggests that it used the simple five-year average of gross meter sets in 2018-2022 for its 2023-2028 forecast, which is consistent with its calculations.[421]

While SCE forecasts an increase in new commercial meters over 2022 recorded, TURN recommends an alternative forecast due to the declining trend in the number of new commercial meters from 2016-2022 and commercial real estate market conditions.[422] TURN's forecast for

[419] Ex. SCE-18V01, p. 86.

[420] Ex. SCE-07V01, p. 99.

[421] Ex. SCE-02V08, pp. 20-21.

[422] Ex. TURN-08 (McGovern), pp. 17-19.

2025-2028 is based on the trendline for new commercial meters from 2016-2022.[423] TURN's forecast compared to SCE's is as follows:

Commercial - New Meter Connections				
	2025	2026	2027	2028
SCE	3,918	3,918	3,918	3,918
TURN	2,582	2,383	2,200	2,031
TURN-SCE	(1,336)	(1,535)	(1,718)	(1,887)

12.1.3 The Commission Should Adopt TURN's Agricultural Gross Meter Set Forecast for the Test Year.

SCE used the five year 2018-2022 average of recorded agricultural meter sets installed to calculate an annual gross meter set forecast for 2023-2028.[424] While SCE forecasts an increase in new agricultural meters over 2022 recorded, TURN recommends an alternative forecast due to the steadily declining trend in the number of new agricultural meters from 2018-2022 and continuing through 2023.[425] TURN's forecast for 2025-2028 is based on the trendline for new agricultural meters from 2012-2023.[426]

In rebuttal testimony, SCE argues that TURN's methodology, "while grounded in historical precedent, may not fully account for the variable nature of agricultural demands and external influences such as economic conditions, technological advancements, and climate change."[427] But the same can be said of SCE's 5-year average.

[423] Ex. TURN-08 (McGovern), p. 17.

[424] Ex. SCE-02V08, pp. 25-26.

[425] Ex. TURN-08 (McGovern), pp. 15-17.

[426] Ex. TURN-08 (McGovern), p. 17.

[427] Ex. SCE-18V01, p. 84.

The Commission should find that SCE's forecast of a near-term rebound in the number of agricultural new connections is unsupported and adopt TURN's more conservative forecast. TURN's forecast compared to SCE's is shown below.

Agricultural - New Meter Connections				
	2025	2026	2027	2028
SCE	184	184	184	184
TURN	102	89	79	69
TURN-SCE	(82)	(95)	(105)	(115)

12.1.4 The Commission Should Direct SCE to Include All Information and Raw Data Supporting Its Customer and New Service Connections Forecasts in Its Direct Testimony Workpapers in Future GRCs.

SCE did not include in its GRC direct testimony workpapers the input data used in its new connections regression and forecast models, such as historical and forecasted housing starts and historical meter counts, nor does it include the historical customer count data used in the development of its customer forecast model.[428] SCE only makes that data available to intervenors through discovery, and in the case of housing data, only subject to a non-disclosure agreement.[429] In contrast, SDG&E and GRC, who have used the same vendors as SCE, provide all of this information on a public basis in their GRC workpapers.[430] TURN witness McGovern explained in testimony that these practices exacerbate the information asymmetry between SCE and intervenors and undermine an intervenor's ability to conduct a thorough analysis, including, e.g., considering the utility's current GRC showing in light of information provided in the last GRC, including confidential information provided only for use in that previous GRC.[431]

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[428] Ex. TURN-08 (McGovern), pp. 23-25.

[429] Ex. TURN-08 (McGovern), pp. 23-25.

[430] Ex. TURN-08 (McGovern), pp. 23-28.

[431] Ex. TURN-08 (McGovern), p. 24.

The Commission should resolve this challenge by directing SCE to include in its future GRC direct testimony workpapers all information and raw data supporting its customer and new service connections forecasts and forecasting models. SCE should provide the required information on a non-confidential basis, unless SCE explains why it cannot publicly disclose the same information that SDG&E and SoCalGas have been able to share. It is reasonable to require SCE to include this information in its GRC direct testimony workpapers because it is fundamental to SCE's new meter and customer forecasts and is a best practice employed by SDG&E and SoCalGas in their GRCs.

In rebuttal testimony, SCE argues that it "already provides the raw data used in forecasting in workpapers, as TURN confirmed in response to a data request," making TURN's request unnecessary.[432] In fact, TURN confirmed that it did NOT receive SCE's modeling workpapers with SCE's initial GRC filing and testimony. Instead, TURN received those files in October 2023 in response to a data request.[433] SCE also offered to contact its vendors to see if it may produce the data it uses in its forecasting models publicly in the next GRC, given the practices of SDG&E and SoCalGas.[434] This step should position SCE well to comply with a Commission order to include the data it uses in its forecasting models in its testimony workpapers in future GRCs (either as public information or with a more examined explanation of why it must treat that information as confidential).

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[432] Ex. SCE-18V01, p. 86.

[433] Ex. SCE-18V01, Appendix A, p. A47 (SCE-TURN-005, Q10).

[434] Ex. SCE-18V01, pp. 86-87.

12.2 Customer Requested System Modifications

12.2.1 Rule 20 Conversions

TURN sponsored testimony addressing Rule 20A Conversions in Ex. TURN-10. Following SCE's rebuttal testimony, TURN conferred with SCE, and TURN agrees that SCE's revised forecast for Rule 20A Conversions in its rebuttal testimony is reasonable.

13. POLES

13.1 Poles O&M

13.2 Poles Capital

14. VEGETATION MANAGEMENT

SCE's Vegetation Management expense forecast represents 54%, the single largest portion, of its Grid Activities forecast.[435] The proposed forecast of $654 m in Vegetation Management expenses in 2025 is an increase of approximately 55% over the recorded Vegetation Management expenses in 2023, $421.046 m in constant 2023 dollars (i.e. 2022 dollars).[436] As described in TURN's equity testimony, California customers are increasingly energy insecure and additional rate increases can lead to evictions and homelessness.[437] This is especially an issue in Black, Indigenous, and other People of Color (BIPOC) communities which are often disproportionately housing and energy burdened.[438] SCE's proposed increase in

[435] Ex. TURN-09-E, p. 1.

[436] Ex. SCE-11, p. A-3.

[437] Ex. TURN-03, p. 5.

[438] Ex. TURN-03, p. 5 ("In addition to increasing homelessness generally, SCE's proposed rate increase will particularly harm Black, Indigenous, and other People of Color (BIPOC) communities which comprise a disproportionate share of the homeless population and have higher average housing and energy burdens than their white counterparts.").

vegetation management costs is incompatible with affordable rates and the Commission should reject the SCE forecast in favor of the TURN proposed alternative of $430.408 m in 2025.

The Commission's consideration of SCE's proposed Vegetation Management portfolio of projects must bear in mind that the utility has made a massive investment, over $4 billion, in covered conductor deployment.[439] This investment has reduced wildfire risk in SCE's territory by 80%.[440] Section 15 of this brief addresses the continued system hardening work that is expected in the SCE territory. At the same time, TURN acknowledges that the Commission has not addressed whether and how certain regulations and requirements for electrical line maintenance are adjusted where covered conductor is installed.[441] TURN similarly acknowledges that the utility must meet current compliance requirements where covered conductor is installed. However, as discussed further below, the extensive deployment of covered conductor should inform the Commission's consideration of discretionary programs.

TURN makes two major adjustments to SCE's proposals, with additional reductions of certain programs. First, TURN's adjustments to the SCE forecast removes the impacts of SCE's reliance on inflated escalation rates when developing program forecasts. The escalation rates relied on by SCE, 10% for Routine Line Clearing and the Hazard Tree Program[442] and 15% for inspections,[443] reflect neither the Federal Reserve's Inflation Targets of 2%[444] or the actual

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[439] Ex. TURN-12, p. 8, T. 2.

[440] Ex. TURN-12, p. 1:19-23.

[441] SCE, Terry Ohanian, 13 Tr. 1346:20-1347:1 (SCE Ohanian).

[442] Ex. TURN-09-E, p. 8: SCE used a 10% rate for routine line clearing; Ex. TURN-09-E, p. 11: SCE used a 10% rate for Dead, Dying and Diseased trees; Ex. SCE-13, Vol. 10, p. 21: SCE includes a 15% increase for inspections costs.

[443] Ex. TURN-09-E, p. 14.

[444] Ex. TURN-09-E, p. 8; Ex. TURN-09-E, p. 11.

inflation rates which, between 2022-2024, were 6.2%, 4.8% and 4% (average of 5%).[445] Regardless of whether the Commission determines it is more important to rely on the target rates or actuals, the 10% and 15% relied on by the utility are inappropriately high. To correct for this, TURN's alternative forecasts rely on either 2% or 5%.[446]

Second, TURN proposes that certain costs for discretionary work be removed from the forecast because the proposed program is not an efficient use of limited ratepayer dollars. TURN recommends that the Commission reject certain discretionary programs as the program benefits do not exceed the costs.

Ultimately, the utility has not demonstrated that its proposed forecast is reasonable and that the resulting budget is consistent with affordable utility service. TURN recommends that the Commission make the following adjustments to SCE's proposed Vegetation Management request:

- As discussed in Section 38.3 of this brief, the Commission should reject the SCE request for a two-way balancing account for Vegetation Management in favor of a one-way account.
- The Commission should adjust inflated unit costs relied on when developing the Routine Line Clearing, Dead, Dying and Diseased Tree and Inspections programs.
- The Commission should reject the SCE budget to fund two types of simultaneous inspections and instead direct the utility to more efficiently manage the transition to Remote Sensing.
- The Commission should reject certain discretionary spending for the Routine Line Clearing and Hazard Tree Management Programs.

[445] Ex. SCE-13, Vol. 10, p. A18.

[446] Ex. TURN-09-E, p. 8, 11; Ex. SCE-13, Vol. 10, p. 20.

- The Commission should reject expansion of the Dead, Dying and Diseased Tree Removal Program beyond current maintenance levels.

As explained further below, the Commission must reject the SCE Vegetation Management proposed budget and should instead adopt TURN's proposed budget adjustments to SCE's 2025 Vegetation Management O&M expenses which result in a budget of $430.408 m. While the detail of the recorded costs provided for 2023 is not sufficiently granular to compare specific programs, the SCE proposal represents an increase of $223 m over 2023 recorded costs. TURN's proposal still represents an increase of $9 m over 2023 costs.

TURN recommends that the Commission should find, based on the information below, that the TURN forecast is sufficient to fund Vegetation Management consistent with safe, reliable, and affordable utility service.

14.1 Inspections Program: The Commission Should Ensure that the Utility Deliver the Promised Benefits of Remote Sensing to its Ratepayers.

SCE proposes $85.146 m for inspections in 2025 including $28.084 m for Traditional Ground Inspections and $55.713 m in Remote Sensing.[447] This compares to $40.706 m in Traditional Ground Inspections in 2022 recorded dollars.[448] TURN recommends the Commission significantly reduce SCE's proposed forecast to protect ratepayers from paying twice for inspections and to correct for SCE's reliance on an inflated escalation factor. Instead, the Commission should adopt TURN's proposed budget of $52.122 m for 2025, subject to the post-test year (PTY) escalation adopted in this proceeding.[449]

[447] Ex. SCE-13, Vol 10, p. 8.

[448] Ex. SCE-13, Vol. 10, p 8.

[449] Ex. TURN-09-E, p. 12.

Ultimately, the utility must determine how to best complete inspections with budget the Commission provides the utility.[450] Although TURN testimony recommends a budget of $47.122 m for ground inspections and $5 m for remote sensing inspections, TURN is neutral as to which type of inspections SCE pursues, provided that the chosen method efficiently and effectively identifies the work that needs to be done and that ratepayers are delivered the promised benefits. TURN's $52 m proposed forecast provides the utility a significant increase over 2022 costs, sufficient to fund the utility's preferred inspection technique.

14.1.1 SCE's Proposal Will Charge Ratepayers for both Ground and Remote Sensing Inspections with No Timeline for Delivering the Efficiencies Promised by LiDAR Technology.

SCE's test year (TY) 2025 forecast would have ratepayers pay for both Traditional Ground Inspections and remote sensing inspections relying on Light Detecting and Ranging (LiDAR) throughout the rate case period, with no clear timeline of when the efficiency benefits of remote sensing will be delivered to customers. SCE proposes that it will complete a full scope of Traditional Ground Inspections as well as LiDAR in 2025.[451] In later years of the Rate Case Cycle, the utility will rely on LiDAR and Traditional Ground Inspections but with a decreasing portion of the territory inspected by ground each year.[452] In the last year of the GRC cycle, the utility will complete LiDAR as well as 20% of a full round of Traditional Ground Inspections.[453]

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[450] Ex. TURN-09-E, p. 14 ("It is ultimately the company's decision how it will allocate resources within the authorized budget adopted in this GRC.").

[451] Ex. SCE-13, Vol. 10, p. 10.

[452] Ex. SCE-13, Vol. 10, p. 10.

[453] Ex. SCE-13, Vol. 10, p. 10.

SCE boasts that LiDAR is ready to be deployed and that it is the preferred method of inspections.[454] The utility emphasizes that LiDAR is not a pilot program, stating "SCE does not view Remote Sensing as being in a pilot stage. To the contrary, SCE views Remote Sensing as a tested and effective means of conducting inspections for vegetation management, having used, improved, and expanded its use of LiDAR since 2019."[455] In comparing LiDAR with Traditional Ground Inspections, SCE states that LiDAR offers more advancements than Traditional Ground Inspections.[456] Additionally, SCE has a "high level of confidence" in LiDAR due to "its established processes, mature vendor relationships, and solid expertise in this space."[457]

The utility explains:

> With the implementation of wide-scale remote sensing, SCE expects a reduced need for ground inspections. In 2025, the full scope of ground inspections will be used to begin validating the remote sensing results on tree-to-conductor clearance and mapping the remote sensing data to SCE's tree inventory. Thereafter, the ground inspections will be necessary primarily to identify hazard tree conditions, conduct ground inspections at locations that are blocked from aerial views necessary for remote sensing (e.g., overhanging tree limbs), and respond to emergent concerns raised by customers.[458]

However, SCE provides no timeline or proof of when/if Traditional Ground Inspections will be completely phased out or how the utility determined the appropriate amount of ground inspections required.[459] SCE states that LiDAR will lead to a more efficient system, while also

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[454] Ex. SCE-13, Vol. 10, pp. 13-16.

[455] Ex. SCE-13, Vol. 10, p. 20.

[456] Ex. SCE-13, Vol. 10, p. 16.

[457] Ex. SCE-13, Vol. 10, p. 13.

[458] Ex. SCE-02, Vol. 10, p. 23.

[459] Ex. SCE-13, Vol. 10, p. 10 ("In 2025, SCE envisages using Remote Sensing to inspect its entire network of approximately 60,000 circuit miles for distribution and transmission. In this year, SCE plans to concurrently employ Traditional Ground Inspections across its territory to facilitate the verification of Remote Sensing data. In 2026-2028, SCE anticipates gradually reducing its use of Traditional Ground Inspections, with 2028 estimated to require 20% of the 2025 forecast for this work.").

requesting that ratepayers simultaneously also fund “less efficient” Traditional Ground Inspections. The longer ratepayers fund two types of inspections, the less value ratepayers receive from any potential efficiencies provided by LiDAR.

Despite this confidence in LiDAR, SCE still argues that it is necessary to complete Traditional Ground Inspections on the same circuits. SCE states, “[o]nly by completing both Remote Sensing and Traditional Ground Inspections for the full network over a single annual inspection cycle can SCE take full advantage of ground inspectors’ validation of remote sensing data, which would facilitate SCE’s development of a reliable and verified digital inventory baseline.”[460] The utility further states that, “predictive models require training through multiple iterations, alongside verification of the models’ results by ground crews.”[461] SCE, however, is not clear how many iterations or how much training is required in order to optimize the use of LIDAR. With each iteration and its attendant costs on ratepayers, any benefits or efficiencies are lost.

If anything, SCE has demonstrated that only one full cycle of dual inspections is required. There is no discussion in SCE’s testimony regarding why more than one cycle of both remote sensing and Traditional Ground Inspection is required in certain locations or why there will still be ground inspections in the last year of this rate cycle. Perhaps most problematic, SCE provides no timeline for a full phase out of ground inspections. This is not the first instance of SCE over-promising and under-delivering ratepayer benefits. In its last rate case, SCE argued that expanded line clearing was a short-term cost, stating “[o]nce the initial deeper trims are complete in 2019-2020, trimming activities are expected to decrease in 2021 because there is less effort

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[460] Ex. SCE-13, Vol. 10, p. 18.

[461] Ex. SCE-13, Vol. 10, p. 18.

involved in maintaining already established trims."[462] However, as discussed in Section 14.2 below, these higher costs are now treated as the new status quo.[463]

In light of the ratepayer experiences with deep trims, SCE's promises of efficiencies are hard to believe especially when ratepayers are paying for "efficient" LiDAR in addition to Traditional Ground Inspections. Because the utility has failed to meet its burden of proof that the extent of the duplicative work requested by the utility is necessary, the Commission should provide a more limited inspections forecast–ensuring the benefits of LiDAR are delivered to ratepayers.

14.1.2 SCE's "Alternative" Proposal Relies on Inflated Escalation Costs to Create an Artificially High Forecast

Rather than justify a short-term increase in costs to launch remote sensing, to make its double inspections forecast appear reasonable, SCE proposes an artificially high alternative forecast for Traditional Ground Inspections without Remote Sensing. SCE proposes a 2025 alternative forecast amount of $79.598 m.[464] This compares to $40.706 m in Traditional Ground Inspections recorded in 2022 and is five million less than the LiDAR forecast for 2025.[465]

In its rebuttal testimony, SCE explained that its alternative forecast uses a "15% increase to reflect initial bids in the new contract cycle as well as the overall competitiveness of this area given other utilities' wages and collective bargaining terms."[466] It is unreasonable for the utility to rely on a 15% escalation rate when inflation targets are 2% and actual inflation rates over

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[462] Ex. TURN-09-Atch1, p. 21: A.19-08-013, Ex. SCE-02, Vol. 6, p. 21.

[463] *See* TURN-09-E, pp. 5-6 discussion of A.19-08-013 routine line clearing forecast.

[464] Ex. SCE-13, Vol. 10, p. 9.

[465] Ex. SCE-13, Vol. 10 p. 8.

[466] Ex. SCE-13 Vol. 10, p. 21.

2022-2024 were 6.2%, 4.8% and 4% (on average, 5%).[467] Further, SCE has since identified the outcome of contract negotiations in 2023. SCE has seen an "approximately 6% increase comparing previous lump sum and current unit rate contracts, completed negotiations Q4 2023."[468]

Especially given the outcome of contract negotiations, coming in almost 10% lower than the assumed escalation, the utility alternative inspections forecast seems designed solely to make the proposal that ratepayers pay for double inspections more reasonable. Because the alternative is unjustified itself, it cannot be used to justify SCE's preferred Remote Sensing alternative, If the utility believes that Remote Sensing is the best path forward for ratepayers, it should do so without unnecessarily raising rates. TURN's proposal provides a significant increase in Vegetation Management budget which the utility can then determine how best to spend, consistent with its responsibilities to provide safe and reliable service.

14.2 Routine Line Clearing: Inflated Escalation and Discretionary Costs Should be Removed from SCE's Routine Line Clearing Budget.

Routine Line Clearing comprises of the largest portion of SCE's proposed Vegetation Management forecast.[469] SCE's rebuttal testimony requests $344.159 m for its routine Line Clearing work.[470] TURN recommends that the Commission reject the SCE proposal and instead adopt an adjusted forecast of $213.776 m.[471]

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[467] Ex. SCE-13, Vol. 10, p. A18.

[468] Ex. 602, pp. 1-2.

[469] Ex. SCE-13, Vol. 10, p. 23.

[470] Ex. SCE-13, Vol. 10, p. 23, T. 11-9

[471] Ex. TURN-09-E, p. 2.

Although SCE may refer to this work as routine, routine does not mean that the work is required under CPUC general orders for maintenance of the utility distribution system. SCE, however, uses the word routine to refer to both their required compliance activities as well as discretionary work.

As discussed above, TURN acknowledges that compliance requirements have not been adjusted to account for the deployment of covered conductor. The utility must continue to complete compliance work consistent with legal and regulatory requirements, regardless of what type of wire is installed. The discretionary work that SCE proposes, however, may not be the best use of scarce ratepayer dollars.

TURN is concerned at the rate of growth of Routine Line Clearing costs. The Routine Line Clearing program relies on a trim rate that is constant regardless of the amount that is trimmed, meaning trimming to compliance distances or beyond compliance distances costs the same amount. It has not always been the case that trims were priced this way. In SCE's last rate case, SCE advocated for a higher Routine Line Clearing forecast, based on the need for more costly deeper trims.[472] In this rate case, SCE has abandoned this argument in favor of a universal trim rate, regardless of the amount trimmed.

SCE also argued that the deeper trim rates it advocated for in its last rate case were necessary and temporary costs, and that those costs would return to maintenance levels in the future.[473] Not only have ratepayers seen even higher Routine Line Clearing costs that do not differentiate between compliance and beyond-compliance trimming, ratepayers have also not received relief in this rate case from those promised temporarily elevated deep trim costs.

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[472] Ex. TURN-09-E, p. 6, Tables 4, 5.

[473] Ex. TURN-09-E, pp. 5-6 discussion of A.19-08-013 routine line clearing forecast and Tables 4, 5.

TURN's reductions to the routine line clearing forecast help deliver the promised benefits to utility customers.

14.2.1 TURN Adjusts Routine Line Clearing Unit Costs to Remove Unnecessarily High Escalation.

SCE's Routine Line Clearing forecast includes a market escalation factor of 10% to adjust for contract cost increases.[474] TURN's alternative forecast relies, instead, on a market escalation factor of 2%, a level that is consistent with the Federal Reserve Inflation Target Rates.[475] It is unreasonable for the utility to ask for, and receive, a 10% escalation rate when inflation targets are 2% and actual inflation rates over 2022-2024 were 6.2%, 4.8% and 4% (on average, 5%).[476]

The 10% escalation rate was intended to account for contract negotiation uncertainties. However, the Routine Line Clearing contracts have now been completed and the actual amounts are known. Trim rates, now a blended cost rather than differentiated for maintenance and deep trims, increased 4.4%.[477] Contracts do see a 65% increase in unit costs for removal of trees.[478] However, only 5% of trees are slated for removal, meaning that the 65% increase in costs for removal only applies to a small portion of total costs. [479]

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474 Ex. TURN-09-E, p. 11.

475 Ex. TURN-09-E, p. 8.

476 Ex. SCE-13, Vol. 10, p. A18.

477 Ex. TURN-602.

478 Ex. TURN-602.

479 Ex. WP SCE-02, Vol. 10, p. 50.

While the increase in costs may exceed the 2% escalation proposed by TURN, it comes nowhere near the 10% assumed by SCE. TURN recommends that the Commission rely on TURN's number as more aligned with observed contract escalation.

14.2.2 TURN Adjusts Unit Costs Downward to Account for the Utility Relying on Elevated Costs the Commission Approved as a Temporary Measure.

SCE's rebuttal testimony states that TURN's testimony "embeds a significant amount of Expanded Line Clearance."[480] This is not accurate. TURN is concerned that SCE has not delivered the cost reductions promised in the last general rate case to ratepayers, and that instead the cost of deeper trims has increased the cost of all trims in this rate case. TURN is also concerned that Expanded Line Clearing, a line item of approximately $8 m has a low Risk Spend Efficiency (RSE).

Unlike the previous rate case, SCE contracts rely on a single blended cost for trims, regardless of the amount of vegetation trimmed. Trims to be completed at this single blended cost include 36,000 deep trims and 790,000 total trims.[481] This blended "unit costs are calculated using 2022 data as inputs."[482]

In the 2021 rate case, the utility expected that there would be a 25% increase in deep trims required with the costs doubling for those deep trims in "High Fire Impact" Areas.[483] Meanwhile in non-high fire impact zones, there was a 12.5% increase in deep trims required with

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[480] Ex. SCE-13, Vol. 10, p. 27.

[481] Ex. SCE-13, Vol. 10, p. 28, fn. 27.

[482] Ex. SCE-13, Vol. 10, p. 23.

[483] Ex. TURN-09-E, p. 6, T. 5.

a 1.25 cost multiplier.[484] While SCE requested these increased costs, the utility assured the Commission that "trimming activities are expected to decrease in 2021 because there is less effort involved in maintaining already established trims."[485]

Table 7: SCE's Table II-9: Routine Line Clearing

2018-2022 Recorded/2025

Forecast Summary of SCE, Cal Advocates and TURN Positions.[486]

Line #	Routine Line Clearing	SCE Recorded					2025 Forecast				Variance from SCE Original Position		Variance from SCE Rebuttal Position	
		2018	2019	2020	2021	2022	SCE Original Position	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor	$ 9,623	$ 15,156	$ 26,916	$ 24,728	$ 25,134	$ 16,658	$ 16,658	$ -	$ -	$ (16,658)	$ (16,658)	$ (16,658)	$ (16,658)
2	Non-Labor	$ 122,220	$ 263,269	$ 351,688	$ 324,079	$ 303,430	$ 331,056	$ 327,501	$ 307,800	$ 213,776	$ (23,256)	$ (117,280)	$ (19,702)	$ (113,725)
3	**Total**	**$ 131,843**	**$ 278,425**	**$ 378,603**	**$ 348,807**	**$ 328,564**	**$ 347,714**	**$ 344,159**	**$ 307,800**	**$ 213,776**	**$ (39,914)**	**$ (133,938)**	**$ (36,360)**	**$ (130,384)**

As the table above shows, while there was a limited decrease in costs in 2022. Costs remained significantly higher than 2019 and especially 2018 levels. The decrease is insufficient to deliver any efficiencies promised to ratepayers, and instead it is an elevated basis from which to derive reasonable unit costs looking forward.

Because of the blended unit cost approach relied on by the utility, it is difficult to determine with specificity and complete confidence exactly how the workload impacts of the deep trims impacted the contract prices. The deep trims were completed concurrently with line clearing costs increases incorporating the impacts of SB 247.[487] Contract prices were then used to determine the unit cost relied on in this case. Considering these changed circumstances, TURN endeavored to unravel the influence to identify a forecast in this case that would deliver the promised cost efficiencies to customers. TURN determined the unit costs without the

[484] Ex. TURN-09-E, p. 6, T.5.

[485] Ex. TURN-09-E, p. 5, citing A.19-08-013, SCE-02, Vol. 6, p. 21.

[486] Ex. SCE-13, Vol. 10, p. 23.

[487] Ex. SCE-10, Vol. 10, p. 43.

"temporary" cost by using the approach relied on by SCE in the 2021 GRC to estimate a new unit cost. The result is an adjusted unit cost which TURN used for the purposes of developing a forecast for SCE. While it may reflect a different approach from SCE's, it provides an estimate of unit costs without the upward influence of "temporary" deeper trims.

14.2.3 Expanded Line Clearing Costs Should be Removed from the Forecast.

The Routine Line Clearing program proposed by SCE includes $8.347 m in discretionary work to complete "Expanded Line Clearing."[488] TURN recommends reducing the Routine Line Clearing program to remove the costs of Expanded Line Clearing because of its extraordinarily low RSE.[489]

As an initial matter, TURN addresses SCE's general position on the information provided by the RSE. SCE notes that, "a comprehensive wildfire risk mitigation should not be based solely on RSEs."[490] To support its position SCE quotes the Commission's Safety and Enforcement Division (SED) which states that it would be "suboptimal from an aggregate risk portfolio standpoint," to focus on RSE as the sole isolated factor in selecting mitigation methods.[491] The SED language referenced is from a 2018 SED report on a PG&E filing that was made in 2017. Not only has the calculation of RSEs developed since this report, in the interim

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[488] Ex. TURN-601, p. 4.

[489] Ex. TURN-09-E, p. 8.

[490] Ex. SCE-13, Vol. 10, p. 34.

[491] Ex. SCE-13, Vol. 10, p. 43, fn. 92; *See* California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company Investigation 17-11-003 (March 30, 2018) via URL: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policydivision/

reports/sed_ramp_evaluation_pge_033018a.pdf, p. 18 ("A potential pitfall with looking at risks and mitigations in isolation based on the RSE scores is that the allocation of risk mitigation spending to the different risks may be suboptimal from an aggregate risk portfolio standpoint.").

the Commission has adopted a settlement approach to calculating and presenting quantitative risk analysis (D.18-12-014) as well as an update to the settlement approach (D.22-12-027). The RSEs calculated by SCE in this case were calculated consistent with the settlement approach which has been vetted by the CPUC.[492]

The SED report on SCE's current approach to calculating risk and the RSE does not include any similar language related to RSE as was included in the 2018 Report on PG&E. Instead, SED recommends that the utility model compliance actions related to vegetation management to determine if the Commission should reassess current compliance requirements:

> Routine Vegetation Management activities are performed to maintain clearances around poles and equipment on the distribution and transmission systems, to comply with current regulations and Commission recommendations. SPD recommends that risk modeling be conducted for Routine Vegetation Management precisely because it is a compliance activity that reduces risk. If they are determined to have low RSE values, the Commission should re-evaluate associated regulatory requirements.[493]

This more recent SED reflects on the role and power of RSEs and demonstrates greater confidence in RSE scores and the information they provide. Therefore, SCE's assertions regarding the role of RSE based on the 2018 Report should be dismissed by the Commission.[494]

As noted above, the Routine Line Clearing program includes $8.347 m in discretionary work for Expanded Line Clearing. SCE clarified that the utility treats compliance activities as "regulatory requirements from General Order (GO) 95 and other statutes."[495] Expanded Line

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[492] Ex. TURN-804, p. 11.

[493] Ex. TURN-804, p. 32.

[494] TURN provides an additional response to SCE's attempts to downplay the usefulness of RSEs in Section 5.3 above.

[495] Ex. TURN-601, p. 2.

Clearing was applied to 36,000 trees.[496] SCE Witness Ohanian clarified that SCE typically trims its trees to meet the [Grid Resiliency Clearance Distance (GRCD)] clearances recommended, but not required, by General Order 95, Rule 35.[497] The 36,000 trees reflect the number of occurrences where the utility was unable to obtain the GRCD and "if we were able to trim these [trees] to the GRCD, it would cost [SCE] the $8 million."[498]

The RSE of Expanded Line Clearing, as calculated by the utility, remains a 4,[499] as compared to 125,431 for Routine Line Clearing otherwise.[500] When SCE's RSE is converted to a cost-benefit ratio (CBR), the CBR of this program is only 0.1,[501] which means that Expanded Line Clearing would provide $10 benefit for every $100 spent.[502] Considering the Expanded Line Clearing budget reflects the costs to extend the trim from the required distance to the recommended distance, the RSE and CBR reflect the cost-effectiveness of expanded clearances. The stark comparison between the RSE for Expanded Line Clearing and Routine Line Clearing suggests that expanded line clearing does not reflect a reasonable investment of ratepayer dollars. Affordability requires that the CPUC reject the program as not cost-effective because of its low RSE. Additionally, the low RSE suggests, consistent with the SED language in the RAMP

[496] Ex. SCE-02, Vol. 10, p. 44.

[497] 13 TR 1379:23-1380:7 (SCE Ohanian).

[498] 13 TR 1386:1-9 (SCE Ohanian).

[499] Ex. TURN-4, App. A, Table 3, p. A-26; Ex. SCE-02, Vol. 10, p. 44, T, II-14.

[500] In Ex. TURN-4, p. A-18, SCE gave its "Distribution and Transmission Routine Vegetation Management" program a RSE score of 125,341. Whereas, in Ex. TURN-601, Table II-7, SCE gave its compliance Routine Line Clearing program a score of 125,431. Given the proximity of these two numbers and the fact that Ex. TURN-601 separated the Routine Line Clearing program into compliance and non-compliance, it is likely that the utility simply transposed numbers to reach the number cited in Ex. TURN-601.

[501] Ex. TURN-4, App. A, Table 3, p. A-26.

[502] Ex. TURN-09-E, p. 8.

report, that the Commission's GO, and particularly its recommended clearances, should be reconsidered.

SCE argues that factors beyond the RSE support continuing Expanded Line Clearing work pointing to the reduction in Tree-Caused Circuit Interruptions (TCCI), a potential "precursor to an ignition."[503] While a reduction in TCCIs does reduce the risk for ignition, only a limited number of TCCIs, however, have led to ignitions. In 2022, three TCCIs caused by living trees, resulted in ignitions.[504] SCE acknowledges that in addition to covered conductor, the utility deploys "fast curve settings and asset inspections" across the high fire risk area (HFRA).[505] There is not information provided on the impact of these programs, in particular fast curve settings, on the reducing the potential for a TCCI to become an ignition. However, SCE's witness Fugere testified that fast curve has a standalone mitigation effectiveness of 40 to 50%.[506] Given the low RSE of Expanded Line Clearing and the failure to demonstrate unique and additional mitigation of risk, there is an insufficient basis to approve Expanded Line Clearing.

In addition to the reductions in unit costs requested by TURN above, the Commission should also remove the $8.347 m of costs of expanded line clearing from the SCE request.

[503] Ex. SCE-13, Vol. 10, p. 31.

[504] Ex. SCE-36.

[505] Ex. SCE-36.

[506] 10 TR 924:16 – p. 925:7 (SCE Fugere).

14.3 Dead, Dying, Diseased Tree Removal: The Dead, Dying, and Diseased Tree Removal Budget Should be Reduced to Remove Inflated Contract Inflation and Expansion of the Program.

SCE requests $30.204 m for its Dead and Dying Tree Removal Program.[507] TURN recommends that the Commission adjust for overinflated contract escalation and adopt a forecast of $25.108 m.

First, consistent with the adjustments to other vegetation management programs and for the reasons described above, TURN adjusts the contract escalation cost from SCE's proposed 10% to 2% consistent with the Federal Reserve Target Inflation rate.[508] The 2% relied on by TURN better reflects the actual contractual increase of 4.4% observed by SCE.[509]

Second, SCE asserts that it will need to remove an increasing number of trees each year because of "anticipated drought conditions."[510] However, the utility provides no evidence of anticipated drought conditions or the impact of said drought on tree mortality to justify the anticipated increase. TURN accordingly also adjusts the forecast to reflect the maintenance level of removals observed in 2023. The result of these two adjustments is TURN's recommended $5.096 reduction in the Dead and Dying Tree Management Program.

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[507] Ex. SCE-02, Vol. 10, p. 79.

[508] Ex. TURN-09-E, p. 11.

[509] Ex. TURN-602.

[510] Ex. SCE-02, Vol. 10, p. 79.

14.4 Hazard Tree Management Program: SCE Fails to Demonstrate that the Hazard Tree Management Program Is a Cost-Effective and Reasonable Use of Ratepayer Funds.

SCE requests $44.202 m for Hazard Tree Management Program (HTMP).[511] TURN recommends that the Commission reject all costs for HTMP.[512]

According to SCE, the HTMP "mitigates ignition and thus wildfire risk stemming from live trees and/or their parts that may appear healthy, but that could fall or blow into SCE's lines."[513] SCE's program targets trees "that are not at risk of growing into the regulatory clearance distance (RCD) as defined by Routine Vegetation Management."[514] This program is discretionary and does not provide benefits sufficient to justify its costs.

SCE calculated a low RSE score of 8 for the HTMP.[515] When the RSE is converted to a CBR, the CBR is either 0.2 using SCE's discount rates, or 0.1 using TURN's discount rates.[516] HTMP would produce only $10 to $20 of benefit for every $100 dollars spent.[517] Given the limited value of this program to ratepayers, TURN recommends the Commission not fund the HTMP.

The Utility suggests that because the HTMP is included in an approved Wildfire Mitigation Plan (WMP) the program is now a legal requirement. SCE erroneously conflates an

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[511] Ex. SCE-13, Vol. 10, p. 38.

[512] Ex. TURN-09-E, p. 9.

[513] Ex. SCE-13, Vol. 10, p. 38.

[514] Ex. TURN-09, p. 9 (Citing Ex. SCE-02, Vol. 10, p. 61).

[515] Ex. SCE-02, Vol. 10, p. 69, T. II-26. When SCE's questionable discount rates are adjusted, SCE's RSE falls to 4. Ex. TURN-4, App. A, Table 3, p. A-25.

[516] Ex. TURN-04, App. A, Table 3, p. A-25.

[517] Ex. TURN-8-E, p. 10; Ex. TURN-04, App. A, Table 3, p. A-25. Table 3 also shows that this program ranks in the bottom 20% of all SCE programs based on SCE's RSE.

approved WMP with compliance with CPUC general orders and statutory requirements. This is inconsistent with precedent. The Commission has previously addressed the meaning of WMP approval, and the role of the CPUC over programs included in an approved WMP:

> The Commission has made it abundantly clear that it does not consider cost recovery when reviewing a utility's WMP; rather, the issue of whether WMP costs are just and reasonable is left to an electrical corporation's GRC or application permitted by Pub. Util. Code § 8386.4(b)(2).797 Therefore, the Commission's ratification of the Office of Energy Infrastructure Safety's approval of specific activities included within a WMP does not indicate the costs of those activities are just and reasonable, nor does it preclude the Commission from determining the appropriate costs for recovery based on the expected pace or scope of a utility's forecasted WMP activities."[518]

The CPUC retains the jurisdiction to determine that certain projects or programs otherwise included in the WMP are not consistent with just and reasonable rates. It does not meet the Utility's burden of proof for demonstrating a project is just and reasonable to simply point to WMP approval. SCE must demonstrate to the CPUC that the program represents the program, pace, and scope to address the identified risk.

SCE also draws a comparison to more recent Office of Energy Infrastructure Safety (Energy Safety) approval of PG&E's Hazard Tree Program: "[Energy Safety] advocated for continuing a hazard tree program similar to SCE's HTMP."[519] SCE argues that the PG&E program identified by Energy Safety is "similar to SCE's HTMP."[520] The approval of a "similar" program is an insufficient basis for the Commission to approve the $44 m HTMP. First, SCE provides no information to the record describing PG&E's hazard tree program and provides no evidence that the two programs are similar. Second, SCE provides no evidence that the grid and

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[518] D.21-08-036, pp. 251-52.

[519] Ex. SCE-13, Vol. 10, p. 42.

[520] Ex. SCE-13, Vol. 10, p. 42.

vegetation conditions between the two utilities are similar and, therefore, the justification for the program in each territory is not comparable. Third, SCE does not demonstrate that the reasons for the adoption of the program by Energy Safety in PG&E's territory are present for SCE. This entire argument should be given no weight by the Commission.

SCE contends that the HTMP is required because it is the best mitigation to address the unique risk of blow in and fall in of live trees.[521] As illustrated in Ex. SCE-35 there are TCCIs caused by live trees beyond the compliance zone (i.e. the trees that would be mitigated by HTMP).[522] However, only a limited number of the TCCIs result in ignitions. Only three TCCIs caused by living trees, inside or outside compliance zones, resulted in ignitions in 2022.[523] These three ignitions caused by live trees, especially without additional context and information on alternative mitigations, do not justify that the $44 m dollar program is a reasonable use of ratepayer dollars. The utility must show that its program is appropriately tailored to the mitigate the risk faced by the utility program, and that the mitigation is the most cost-effective means of addressing that risk. The low RSE of HTMP suggests that other alternatives may be better suited to address this risk. SCE did not provide alternatives to the HTMP–either alternative mitigations or an alternative scope of the program. For instance, SCE maintains a "Tree Risk Calculator to conduct Level 2 Assessments and recommend mitigations based on the risk score."[524] Indeed, a smaller program with a better-defined Tree Risk Calculator scores may be able to accurately

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[521] Ex. SCE-13, Vol. 10, p. 43 ("Only HTMP addresses the primary root cause of TCCIs, with live, visibly healthy trees or tree parts known to be linked to tree-caused ignition events.").

[522] Ex. SCE-35.

[523] Ex. SCE-35; Ex. SCE-36.

[524] Ex. SCE-37.

capture the limited trees that threaten an ignition at a more reasonable budget. In the absence of a reasonably scoped program the Commission is required to reject SCE's proposed HTMP.

14.5 Seasonal Patrols/AOC/Emergent Work

14.6 Structure Brushing

14.7 Environmental Support For Vegetation Management

14.8 Wildfire Mitigation Vegetation Management Technology Solutions

15. WILDFIRE MANAGEMENT

15.1 Overview

15.2 Grid Hardening

15.2.1 Summary of SCE's Proposal and TURN's Recommendations

For the 2025-2028 rate case period, SCE proposes a drastic change to its wildfire mitigation strategy by dramatically increasing its reliance on undergrounding. Over this period, SCE proposes to underground 580 overhead miles with at a forecast four-year cost of $3.27 billion, an average of $815 million per year.[525] By contrast, SCE spent an average of $16 million per year on undergrounding in 2020-2023.[526] In this GRC, undergrounding consumes more than half of SCE's capital forecast for grid hardening,[527] whereas, in SCE's prior GRC, over 90% of SCE's wildfire management capital forecast was for covered conductor.[528]

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[525] Ex. SCE-04, Vol. 5, Part 2A, p. 10.

[526] Based on Ex. SCE-04, Vol. 5, Part 2A, p. 9, Figure I-1. The 2023 figure is a forecast.

[527] Ex. SCE-15, Vol. 5, Part 2, p. 3, Table I-2. Undergrounding is 53 percent of SCE's 2023-2028 grid hardening forecast.

[528] D.21-08-036, p. 187. Undergrounding was not even discussed in SCE's 2021 GRC decision.

According to the utility, the driver of the shift in SCE's grid hardening policy is its classification of certain miles as "Severe Risk Areas" (SRA), which SCE describes as the "riskiest locations."[529] Out of SCE's total 580-mile undergrounding proposal, 570 of those miles are in the remaining unhardened miles in locations SCE designates as SRAs.[530] As will be discussed below, SCE's qualitative and opaque criteria for determining SRAs do not correspond with the CPUC's prescribed S-MAP methodology for calculating risk scores in D.18-12-014 and include a significant proportion of miles that are relatively low risk under the CPUC's risk scores. This mismatch between "severe" risk miles classified as SRAs and the miles with the highest risk scores under the S-MAP framework occurs even though the S-MAP risk scores include quantification of many of the same criteria used by SCE to designate an SRA.

TURN recommends major revisions to SCE's proposal that would achieve the same amount of risk reduction at $2 billion less cost to ratepayers.[531] Covered conductor should continue to be the centerpiece of SCE's grid hardening efforts, with undergrounding serving a more limited role targeted to the truly riskiest locations where this much higher cost mitigation is warranted. The details of TURN's recommendation, including how it compares with SCE's proposal, are presented in Section 15.2.6 below.

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[529] Ex. SCE-15, Vol. 5, Part 2, p. 20.

[530] *Id.*

[531] Ex. TURN-12-E (Borden/TURN), p. 2.

15.2.2 Covered Conductor Reduces Significant Wildfire Risk, Can Be Enhanced with Emerging Technologies, Is Much More Cost-Effective than Undergrounding, and Can Be Deployed Much More Quickly

SCE has achieved significant risk reduction with covered conductor in a short time period.[532] Covered conductor should remain the primary grid hardening tool because it is significantly more cost-effective than undergrounding and can be deployed more quickly.

Notably, SCE concurs with this overall assessment of the benefits of covered conductor, describing it as a "prudent and cost-effective mitigation" that "can buy down risk in a relatively short amount of time."[533] Most importantly, as SCE states, covered conductor "mitigates the risk drivers that tend to cause the largest fires."[534]

SCE also touts the benefits of its installed covered conductor in reducing the number and duration of PSPS events because of its ability to reduce the risk of contact from foreign objects. SCE states that it was able to raise wind-speed de-energization thresholds from National Weather Service "advisory" levels, 46 mph gust speed, to "warning levels" of 58 mph gusts on 2,300 miles, including 64% of the Tier 3 HFTD miles where it has installed covered conductor.[535] As required by D.21-08-036, SCE also provides data showing dramatic reductions in PSPS activations, minutes, and affected customers because of expedited installation of covered conductor.[536]

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[532] This point is discussed further in Section 15.2.3 below.

[533] Ex. SCE-04, Vol. 5, Part 2A, pp. 38-39.

[534] Ex. SCE-04, Vol. 5, Part 2A, p. 52.

[535] Ex. SCE-04, Vol. 5, Part 2A, p. 46.

[536] SCE reports that for 70 high PSPS frequency circuits where it expedited covered conductor in 2022, PSPS de-energizations fell from 60 in 2020 and 2021 to 4 in 2022, affected customers fell from 180,000 to 1,900, and customer minutes of interruption (CMI) fell from 50,000,000 to 800,000. Ex. SCE-04, Vol. 5, Part 2A, p. 45.

SCE calculates the overall mitigation effectiveness of covered conductor as 73%.[537] While this is less than the 98% effectiveness SCE reports for undergrounding, SCE notes that covered conductor can approximate the effectiveness of undergrounding when teamed with complementary emerging technologies such as REFCL and spacer cable.[538] SCE has determined that REFCL has significant potential risk reduction benefits per dollar[539] and is already forecasting significant use of REFCL, which it calls a "measured deployment" while continuing to validate its mitigation effectiveness, forecasting $240 million in capital expenditures for this rate case period, at a unit cost of $100,000 per overhead mile.[540] SCE states that spacer cable is a particularly useful enhancement to covered conductor where tree fall-in risk is high and that the utility has initiated a pilot, which if successful, would support use of spacer cable as an additional mitigation.[541] Thus, covered conductor delivers high mitigation effectiveness more quickly than undergrounding, and in the longer term, can be supplemented with other technologies that, when combined with covered conductor, appear likely to approximate undergrounding's effectiveness.

Covered conductor delivers its significant benefits at a unit cost per overhead mile that is ***six times less*** than the cost of undergrounding on a weighted average basis, according to SCE's forecast.[542]

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[537] Ex. SCE-15, Vol. 5, Part 2, p. 30.

[538] Ex. SCE-04, Vol. 5, Part 2A, pp. 16-17.

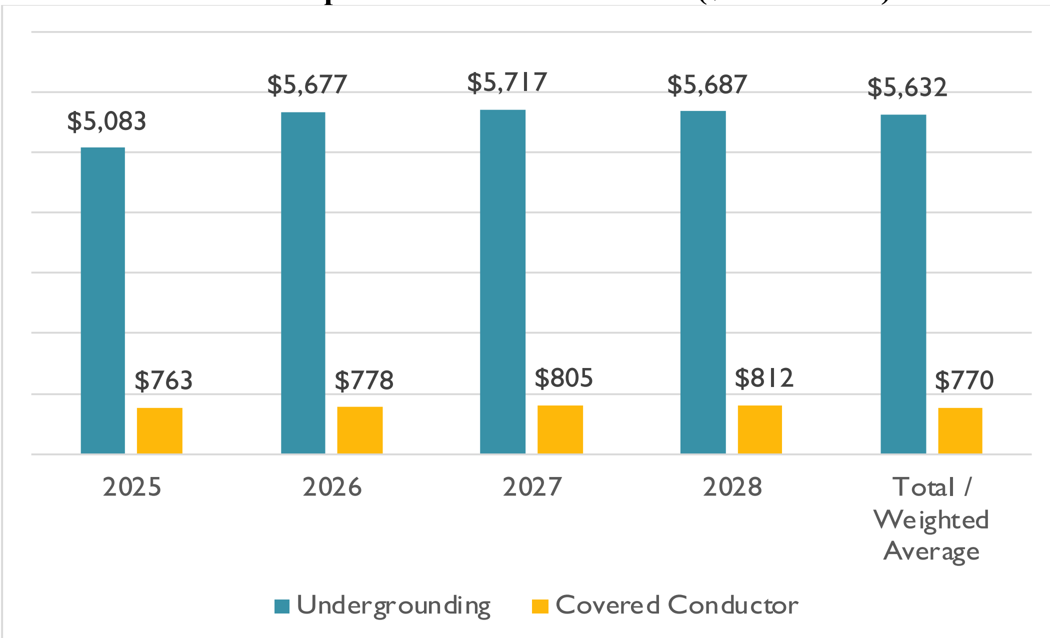
[539] Ex. SCE-04, Vol. 5, Part 2A, p. 82.

[540] Ex. SCE-04, Vol. 5, Part 2A, pp. 83-84; Ex. TURN-12-E, p. 24 and fn. 29.

[541] *Id.*, pp. 16-17.

[542] Ex. TURN-12-E, p. 23.

Figure 5: SCE Forecast Unit Cost of Undergrounding vs. Covered Conductor per Overhead Circuit Mile ($ Thousands)[543]



Relatively low unit costs and high mitigation effectiveness make covered conductor far more cost-effective than undergrounding. SCE's modeling in connection with its direct testimony indicates covered conductor is about 67 percent more cost-effective, on average, than targeted undergrounding,[544] a point SCE did not challenge in rebuttal.[545] However, this measure of covered conductor's superiority is actually a significant understatement, because SCE

[543] *Id.*, p. 24.

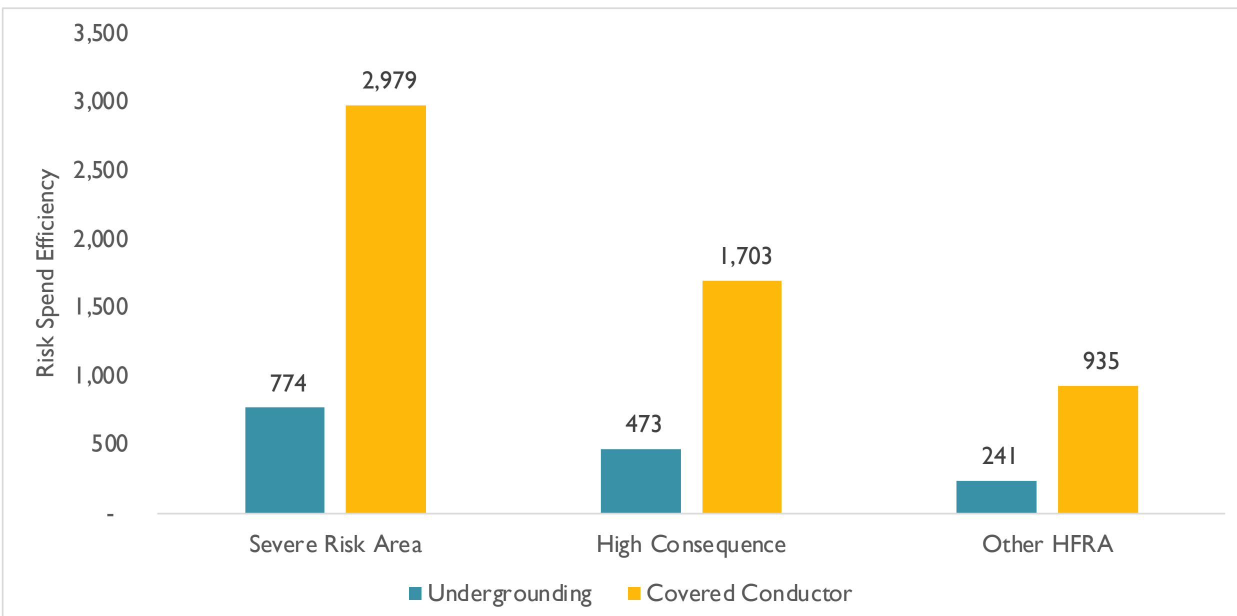
[544] Ex. TURN-12-E, p. 25.

[545] TURN's testimony discussed in this section relied on the modeling data SCE provided in connection with its direct showing in this case, which TURN had sufficient opportunity to review, analyze, and address in its testimony. SCE's rebuttal testimony did not challenge any of TURN's findings and conclusions showing the enormous cost-effectiveness advantage of covered conductor over undergrounding. Instead, SCE's rebuttal presented a complex new analysis. Even though TURN had limited time to review that new analysis, TURN was able to identify serious problems that invalidated its results, as discussed in Section 15.2.7 below.

calculated cost-effectiveness based on its proposal rather than by an apples-to-apples comparison of the two alternatives if deployed *to the same circuit segments*.[546]

Using the data supporting SCE's direct showing, TURN was able to fill this gap in the record by performing two apples-to-apples comparisons, both of which show an even greater cost-effectiveness advantage for covered conductor. Neither were challenged by SCE. The first figure below shows that, when the two alternatives are compared on the same circuit segments, covered conductor is actually ***between 260 and 288 percent*** more cost-effective than undergrounding.

Figure 6: Risk Spend Efficiency of Undergrounding vs. Covered Conductor[547]



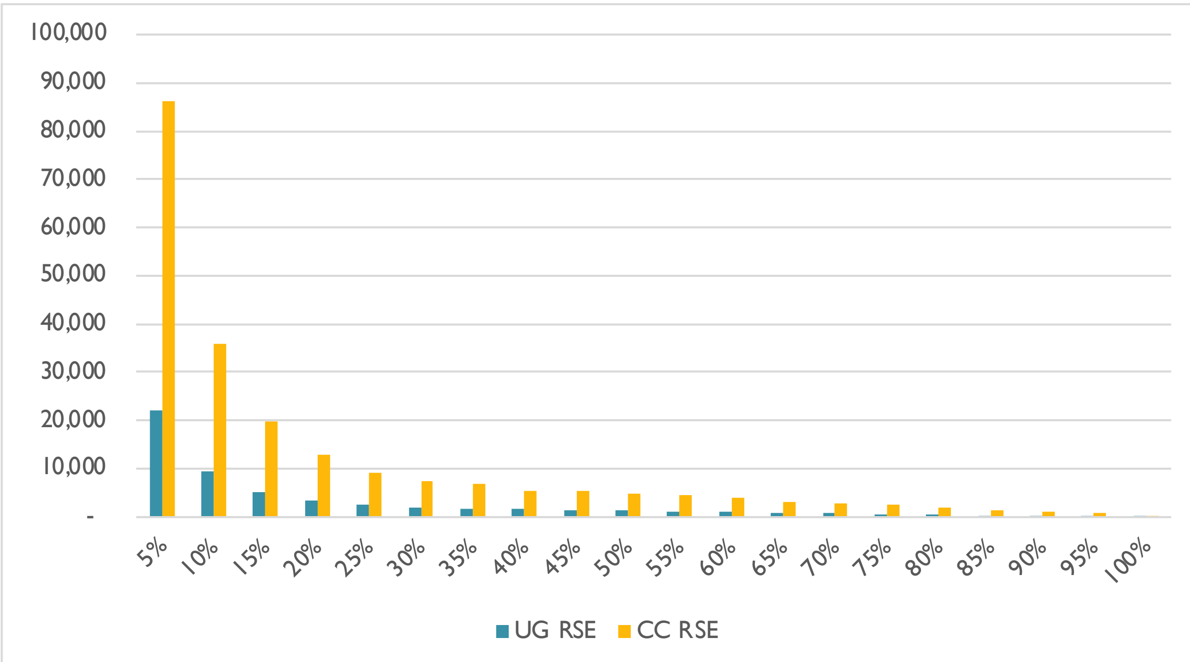
The following figure shows relative cost-effectiveness based on more granular risk tranches, using a slightly different methodology that aggregates circuit segments together at the project

[546] Ex. TURN-12-E, p. 25.

[547] Ex. TURN-12-E, p. 25, Figure 13.

level (rather than the circuit segment level, shown above) and sorts from highest to lowest undergrounding RSE.[548]

Figure 7: Risk Spend Efficiency of Undergrounding vs. Covered Conductor[549]



For each risk percentile shown in the figure above, covered conductor is more cost-effective than undergrounding. At the even more granular individual circuit segment level, covered conductor is more cost-effective than undergrounding on 99.6 percent of circuit segment miles (1,821 of 1,828).[550]

Each of TURN's cost-effectiveness comparisons discussed in this section relied on the modeling data SCE provided in connection with its direct showing in this case. SCE's rebuttal testimony did not challenge any of TURN's findings and conclusions based on that data showing the enormous cost-effectiveness advantage of covered conductor over undergrounding.

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548 Ex. TURN-12-E, p. 26.

549 *Id.*

550 *Id.*

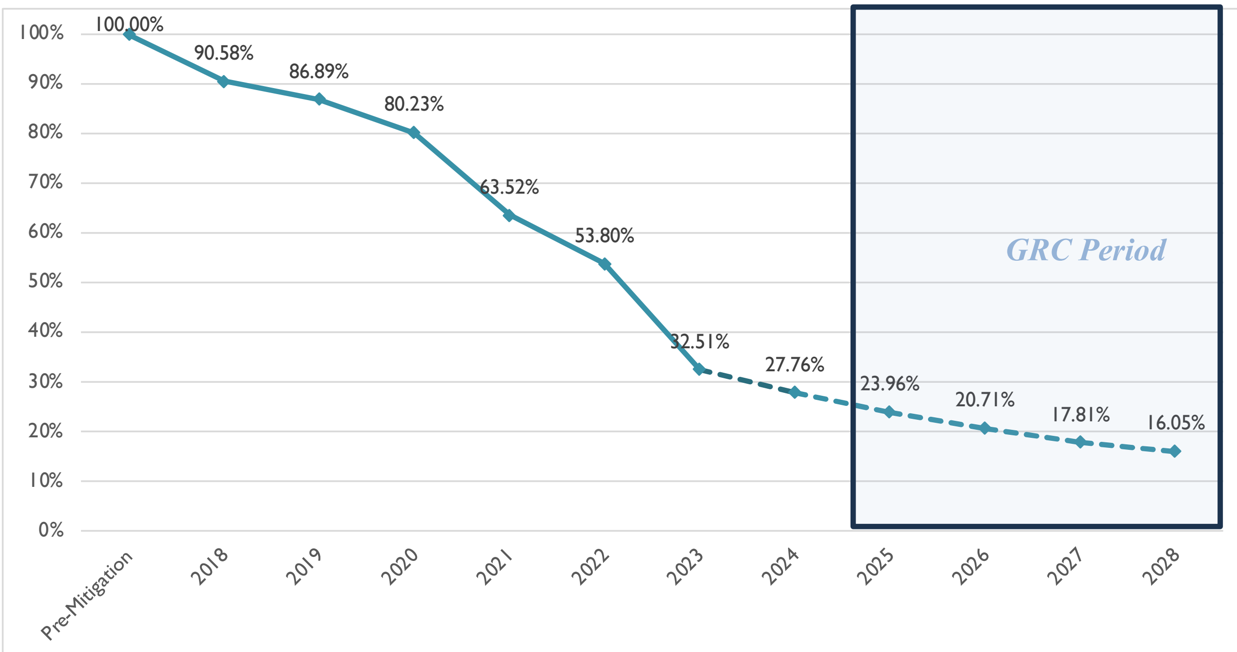
15.2.3 SCE's Proposed Massive Investment in Undergrounding Would Be a Poor Use of Ratepayer Funds In Light of the Significant Risk Reduction that Has Already Been Accomplished With Covered Conductor, at Ratepayer Expense

SCE's significant ratepayer-funded investment in covered conductor has resulted in massive risk reduction, leaving a relatively small percentage of risk remaining on SCE's system. The figure below shows SCE's estimate of risk reduced due to grid hardening (covered conductor and undergrounding) and fast curve settings, which cut off power when vegetation or another object come in contract with a powerline. As shown, by the end of 2024, SCE estimates a 72% reduction[551] in wildfire risk. The majority of this risk reduction, 77 percent, is due to grid hardening, almost entirely covered conductor.[552]

[551] Based on the figure below: 100% initial wildfire risk minus 27.76% (rounded to 28%) equals 72%.

[552] Ex. TURN-12-E, p. 19. Risk reduction from 2023 to 2024 is calculated based only on SCE's expected risk reduction percentage solely from grid hardening (primarily covered conductor). *Id.*

Figure 8: Wildfire Risk Remaining After Grid Hardening and Fast Curve Settings (2018-2028)[553]



Because of the significant risk reduction that has already been achieved, SCE anticipates much less risk reduction in the 2025-2028 rate case period, only 12%,[554] compared to the 72% risk reduction from 2018 to 2024. Incongruously, to achieve this additional 12% risk reduction, SCE proposes to ***increase*** its grid hardening spending from $3.5 billion in 2021-2024 to $4.2 billion in 2025-2028.[555]

In light of the significant and successful grid hardening efforts that ratepayers have already funded and the higher cost-effectiveness of covered conductor, the Commission's Safety Policy Division's (SPD) RAMP Evaluation Report questioned the wisdom of SCE's proposed massive investment in undergrounding:

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[553] *Id.*, p. 21.

[554] Based on the figure above: 28% (rounded) remaining wildfire risk in 2024 minus 16% remaining risk in 2028 (rounded to 28%) equals 12%.

[555] Ex. TURN-12-E, p. 20.

> Given the lower RSE, SPD staff question the appropriateness of substantial investment of ratepayer funds for TUG [Targeted Undergrounding] after the large-scale implementation of the CC [Covered Conductor] program has been underway for years. The [covered conductor program] was supposed to prioritize and install CC on the highest-risk circuit segments in the program's early years. Hence, there is no widespread need for TUG since the highest-risk circuit segments have CC installed.[556]

TURN could not agree more. In assessing whether SCE's broad-scope undergrounding proposal is appropriate, the Commission should account for the huge previous investment and significant risk reduction achieved with covered conductor, given that there is now significantly lower absolute risk than when SCE embarked on grid hardening measures in 2018 and the fact that ratepayers face the burden of ever-increasing rates and bills.

15.2.4 SCE Wrongly Relies on Its Flawed Designation of So-Called 'Severe Risk Areas' (SRA) to Define the Scope of Its Undergrounding Proposal

15.2.4.1 The Scope of SCE's Undergrounding Proposal Hinges on Its Definition of SRAs

SCE bases its grid hardening forecast largely on its designation of certain portions of its service territory as "Severe Risk Areas" (SRAs), where SCE states overhead powerlines must be undergrounded in most instances to limit or eliminate risk. The upshot is to make undergrounding the default choice in SRAs, rather than determining the best alternative based on location-specific conditions.

[556] SPD Staff Evaluation Report on SCE's 2022 RAMP, A.22-05-013, Nov. 10, 2022, p. 35, made a part of the record of this case by ALJ ruling. Tr. Vol. 10, p, 996:20 – p. 997:3.

SCE's SRAs are based on the following criteria, only one of which need be present to qualify a location as an SRA:[557]

1. Population egress constraints, high fire frequency, and burn-in buffer into egress locations.[558]
2. Significant fire consequence – Acres burned consequence greater than 10,000 over an 8-hour unsuppressed model simulation.
3. High winds – Locations, which if fully covered with covered conductor, would still be subject to high PSPS likelihood.
4. Communities of Elevated Fire Concern (CEFCs) – Smaller geographic areas where terrain, construction, and other factors could lead to smaller, fast-moving fires threatening populated locations under benign (normal) weather conditions.

Notably, as discussed below, SCE can and does take all of these factors into account in its S-MAP required quantitative risk modeling. In order to justify the complication and expense of undergrounding, SCE uses opaque qualitative criteria to label circuits as "severe risk," regardless of how the S-MAP risk score of these circuits compares with others.

Based on these criteria, SCE identifies 3,226 miles of its service territory that are SRAs. However, most of these miles are already hardened or will be by 2024 (primarily with covered conductor); only 590 miles of SRA remain that will not be hardened through 2024, almost all of which the utility seeks to underground in the GRC period.[559]

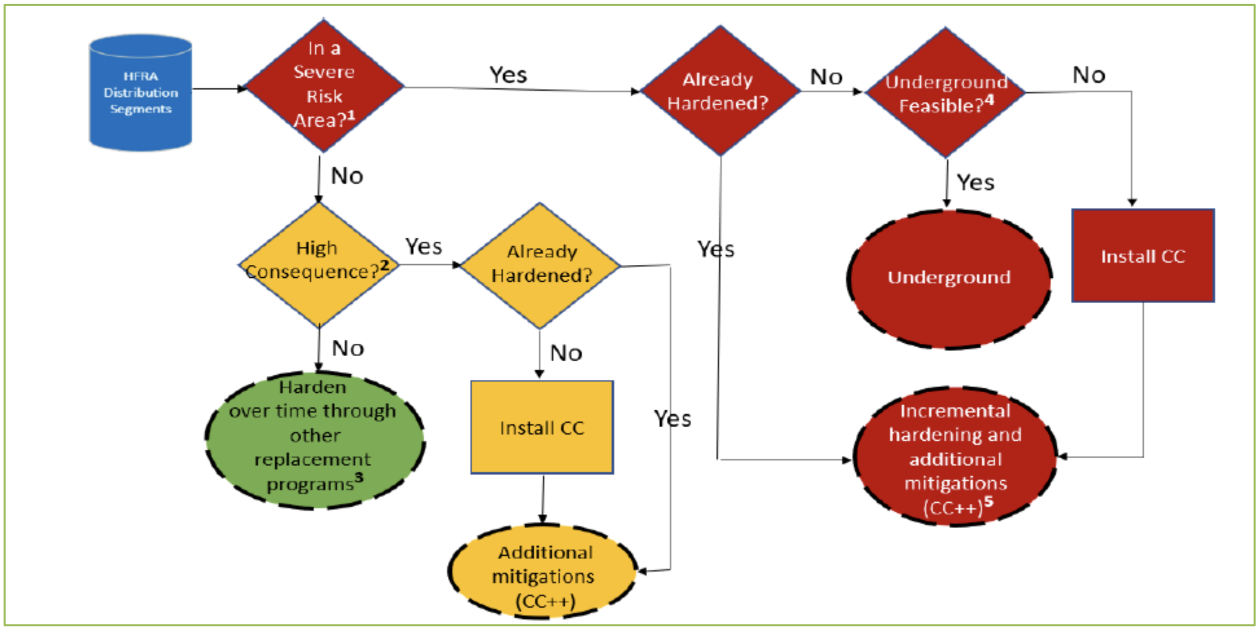
SCE proposes that it decide which grid hardening alternative to deploy based on the following decision tree.

[557] SCE-04, Vol. 5, Part 1A, pp. 23-24.

[558] SCE states in SCE-04, Vol. 5, Part 1A, p. 50 fn. 48: "Burn-in buffers are areas adjacent to the egress constrained areas such that if the fire originated there, could enter the egress constrained area."

[559] SCE-04, Vol. 5, Part 1A, Table II-7, p. 44.

Figure 9: SCE Decision Process for Grid Hardening[560]



Notable in this decision tree is the fact that whether undergrounding is deployed hinges on whether a location is an SRA. The only situation in which unhardened SRA miles will not be undergrounded is when SCE deems undergrounding not "feasible," which SCE says is based on "factors such as terrain, cost and customer constraints."[561] SCE clearly sees such infeasibility as a rare occurrence, as SCE proposes that 580 of the 590 SRA miles to be hardened in 2025-2028 would be undergrounded.[562] At a high *average* forecasted unit cost of over $5 million per mile, it is not clear what, if any, cost threshold would be required for SCE to determine a project is "infeasible."

[560] *Id.*, p. 45, Figure II-19.

[561] *Id.*, fn. 4 to Figure II-19.

[562] SCE-04, Vol. 5, Part 1A, Table II-7, p. 44.

Importantly, SCE's decision tree gives no consideration to a comparison of cost-effectiveness values for undergrounding and overhead hardening at the location in question. Thus, even though each location is different with different risk drivers and cost considerations, SCE would rather use a default-to-undergrounding approach in SRAs rather than performing a meaningful comparison of alternatives.

15.2.4.2 SCE's SRA Designations Amount to an End Run Around the S-MAP Risk Assessment Framework It Agreed to and Is Required to Use

SCE's expansive undergrounding proposal relies on its claim that, even after six years of extensive grid hardening, supposedly in the highest risk locations, 580 remaining unhardened miles have such "severe" risk as to require undergrounding. As this section will show, the S-MAP risk modeling required by D.18-12-014 does not support this conclusion.

Instead, SCE resorts to qualitative criteria that use *a different definition of risk* to support the company's desired undergrounding plan. In the settlement adopted in D.18-12-014, SCE and the other large utilities agreed that risk should be defined as likelihood of risk event (LoRE) times consequence of risk event (CoRE).[563] However, as SCE does not dispute,[564] its SRA criteria completely ignore the likelihood side of the equation and only consider consequences, a fundamental departure from the definition of risk SCE is required to use to assess its current level of risk throughout its system. Moreover, SCE's decision-making methodology treats all

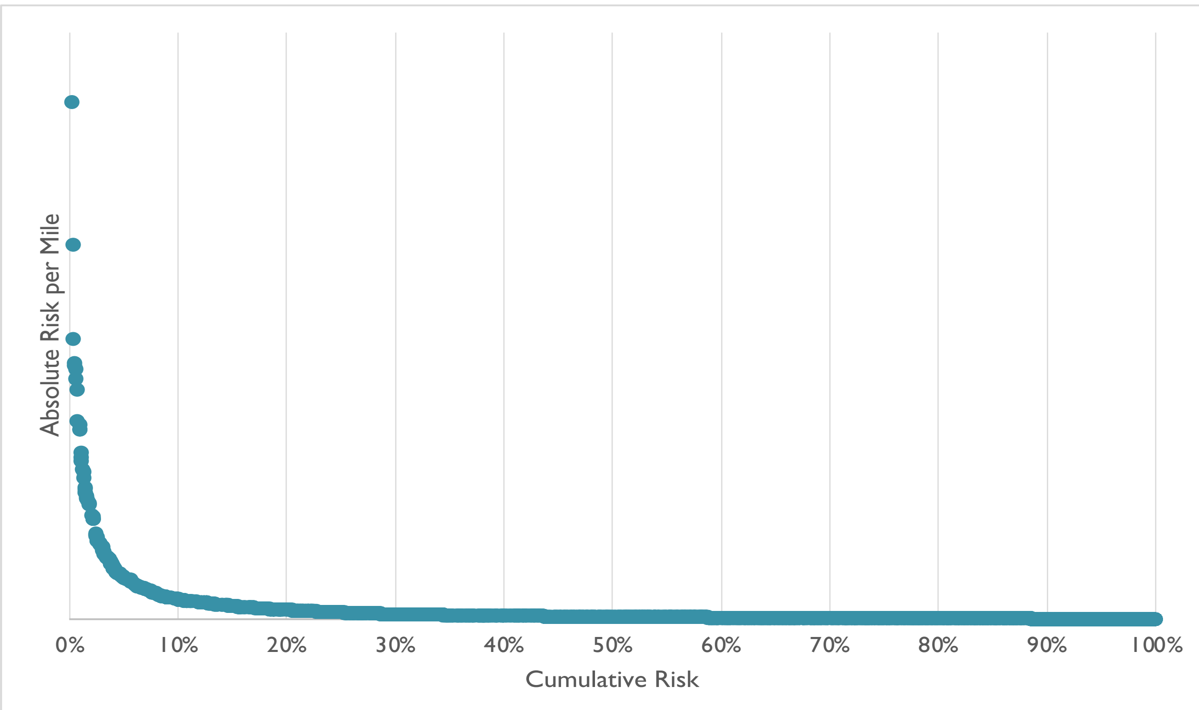
[563] Ex. TURN-12-E, p. 8.

[564] Ex. SCE-15, Vol. 5, Part 2, p. 27 (SCE's SRA analysis "does not include quantitative LoRE values . . .")

580 circuit miles that meet *any* of the proposed criteria as effectively the same, instead of the risk ranking by location that is afforded by the S-MAP risk assessment framework.[565]

As a result of the disconnect between the SRA criteria and the S-MAP risk framework, many of the circuit segments that SCE paints broadly as having "severe" risk actually have very low relative and absolute risk measured by S-MAP risk scores, as shown in the figure below.

Figure 10: Absolute Risk per Mile Values of Circuit Segments in "Severe Risk Areas"[566]



The figure ranks SRA circuit segments from highest to lowest risk per mile by segment according to SCE's own S-MAP risk analysis. The x-axis shows the percent of cumulative risk, while the y-axis shows the risk per mile of the circuit segment. The figure not only shows that

[565] Ex. TURN-12-E, p. 8.

[566] Ex. TURN-12-E, p. 9, Figure 5.

most of the SRA segments have very low risk per mile, but that there is enormous variation in risk among the broad swath of segments SCE uniformly classifies as "severe" risk areas.[567]

Other analyses conducted by TURN highlight the lack of rigor in SCE's categorization approach. SCE's risk data at the circuit segment level showed that 554 out of the total of 588 miles that SCE classifies as SRA are in the bottom 50 percent of risk calculated under the S-MAP framework; 404 miles are in the bottom **10%.**[568] SCE's approach also misses some high-risk miles -- 44% of unhardened miles in the top 50% of risk as measured by S-MAP -- that might warrant at least being considered for undergrounding.[569]

SCE's rebuttal does not dispute TURN's analysis showing the mismatch between SCE's SRAs and the company's S-MAP risk scores. In fact, SCE acknowledges that 70% of the miles in its undergrounding program would not address the top 50% of risk as measured by the S-MAP risk scores.[570] Instead, SCE quibbles that some miles in a circuit may be high risk and others may be low risk.[571] However, when the illustrative map that SCE presents was revised based on "isolatable circuit segments" that aggregate segments to the project level (i.e., the level at which projects are implemented, which is what TURN's proposal is based on),[572] the maps show, as expected, that high and low risk segments are not interspersed -- high risk segments are grouped in one area and low risk segments in another.[573]

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[567] *Id.*, p. 9.

[568] *Id.,* p. 11.

[569] *Id.*, pp. 9-10.

[570] Ex. SCE-15, Vol. 5, Part 2, p. 19, fn. 48.

[571] *Id.*, p. 11.

[572] Ex. TURN-12-E, p, 27.

[573] Ex. TURN-801, SCE response to TURN DR 113, question 4, Figures 2 and 3. TURN's proposal thus addresses SCE's concern regarding "project level" considerations by using much more aggregated data

The upshot is to validate TURN's point that SCE's SRAs include an astonishingly high percentage of circuit miles that would justify SCE performing undergrounding projects in areas in the bottom 50% of risk as measured by the S-MAP framework.[574] Undergrounding lines in areas with relatively low risk, without due consideration of viable alternatives like covered conductor, is a poor use of ratepayer funds.

15.2.4.3 SCE's SRA Criteria Are a Poor Fit for Explaining When Undergrounding May Be Superior to Overhead Hardening

The SRA criteria identified by SCE do not provide a sound basis for choosing undergrounding over covered conductor or covered conductor combined with emerging technologies such as REFCL. Undergrounding may be a superior alternative to covered conductor in locations, for example, where the risk drivers are not aligned with the best use case of covered conductor, where undergrounding can be accomplished for a reasonably comparable cost, or where the absolute risk (based on likelihood and consequence per the S-MAP risk scores) is relatively high, among other possible scenarios. The following table, presented in TURN's testimony, shows the mismatch between SCE's SRA criteria and reasons that would make undergrounding the superior alternative.[575]

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provided by SCE itself in response to SPD's request in the RAMP. SCE's argument is therefore irrelevant to TURN's proposal.

[574] SCE's rebuttal points to Table II-6 on p. 15 showing that risk per mile is higher in areas designated as SRA. (Ex. SCE-15, Vol. 5, Part 2-E, p. 15) But the table also shows that SRAs only capture about half of the risk calculated under the S-MAP framework. Thus, SCE's table reinforces TURN's point that the risk in SRAs is not homogenously "severe" and does not justify a uniform and highly expensive response of undergrounding almost all miles that SCE identified as SRA.

[575] Ex. TURN-12-E, pp. 12-13.

SRA Criteria	Does this demonstrate undergrounding is the preferred solution?
1. Population egress constraints, high fire frequency, and burn-in buffer into egress locations.	These criteria do not necessarily support undergrounding over covered conductor. They are not related to the location-specific drivers that determine the effectiveness of overhead hardening compared to undergrounding and otherwise, do not show why undergrounding is superior. SCE does not explain why its SRA designation better explains where undergrounding is preferable compared to its circuit segment risk scores, which quantitatively capture many of the risk factors in these criteria.
2. Significant fire consequence – Acres burned consequence greater than 10,000 over an 8-hour unsuppressed model simulation.	A high consequence score does not necessarily mean risk drivers would not be significantly mitigated by covered conductor.
3. High winds – Locations, which if fully covered with covered conductor, would still be subject to high PSPS likelihood.	Of the four criteria, this one best explains why undergrounding may be preferable. Still, from this criterion, it is not clear what the likelihood or frequency of these high wind events are, nor whether this likelihood justifies the high expense of undergrounding. Further, undergrounding is by far the most expensive and likely least cost-effective mitigation to address PSPS risk. Most other programs intended to mitigate PSPS risk would be significantly more cost-effective and in the interest of ratepayers: customer care programs – batteries and generator back-up, sectionalization, switching plans, mobile generator deployment, and likely others.
4. Communities of Elevated Fire Concern (CEFCs) – Smaller geographic areas where terrain, construction, and other factors could lead to smaller, fast-moving fires threatening populated	Same problems as identified for the first and second criteria.

locations under benign (normal) weather conditions.	

SCE's rebuttal testimony does not challenge any of these points.

15.2.4.4 SCE's Justification for Attempting to Circumvent the CPUC's Mandated Risk Assessment Framework Is Without Merit

SCE defends its use of a process that ignores both the CPUC's definition of risk and the risk scores from the CPUC's required framework on the grounds that its approach is "holistic" and uses both qualitative and quantitative analysis.[576] SCE claims that its approach is superior because it mitigates gaps in data and considers a wider range of risk factors.[577] SCE's rebuttal names a litany of factors that supposedly are only considered under its SRA approach.[578]

The fatal problem with SCE's argument is that all of the factors it lists can and should be part of the S-MAP risk analysis as needed to yield the utility's best estimate of risk. As noted, the S-MAP framework mandates that risk scores be based on likelihood of the risk event (LoRE) multiplied by the consequences of the risk event (CoRE).[579] Utilities are to provide their best estimates of these values at "as deep a level of granularity as reasonably possible."[580] These

[576] Ex. SCE-15, Vol. 5, Part 2, p. 7.

[577] *Id.* Similarly, SCE argues that the most useful data for quantitative risk analysis is not always up to date. *Id.*, p. 10.

[578] *Id.*, pp. 8, 14-15. The listed factors include: egress constraints, engineering reviews, risk management evaluation, meteorologic studies, geospatial and topographical analysis, construction practicality and feasibility, photographic evidence, local knowledge, fuel loading, potential risk drivers, wind patterns, geographic features, and proximity to open wildlands.

[579] D.18-12-014, adopting S-MAP Settlement, Att. A., Row 13. *See* Section 5.3.1 above.

[580] *Id.*, Row 14.

estimates are to be based on data "whenever practical and appropriate."[581] However, the S-MAP framework is clear that "the available data should not restrict the application of the risk assessment methodologies."[582] Where the utility believes there are data limitations or gaps, "SME judgment should be used if the methodologies require use of data that is not available."[583]

The bottom line is that, under the S-MAP framework, utilities should use whatever data they believe will provide the best estimates of risk in a given situation. Where the utility is dissatisfied with the available data – because the utility believes the data has gaps or is not up to date -- it can, and indeed must, use SME judgment to supplement the data. Thus, every factor that SCE claims must be assessed to accurately evaluate risk should have been considered in SCE's quantitative risk analysis. In response to a TURN data request concerning its rebuttal contentions, SCE had no choice but to concede this point. It acknowledged that the S-MAP framework is capable of addressing all the factors SCE lists and correctly noted that the S-MAP framework "recognizes the need to supplement MAVF . . . through the use of SME judgment. . . ."[584] Moreover, SCE states that it incorporates both egress risk and PSPS risk – two of the key SRA criteria -- into its wildfire risk modeling and risk scores at the circuit segment level.[585]

In sum, SCE's criticisms of the supposed shortcomings of the S-MAP framework are completely unfounded. If SCE is dissatisfied with its data, it should either work harder at improving and updating the data or, where not possible, supplement the data with SME

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581 *Id.*, Row 31.

582 *Id.*

583 *Id.*

584 Ex. TURN-802, SCE's response to TURN DR 113, Question 5(a).

585 SCE-04, Vol. 5, Part 1A, pp. 15, 17.

judgment. The answer is not to invent a whole new way of assessing risk on its system that bypasses the CPUC's decade-long effort to develop a detailed and comprehensive uniform risk assessment methodology,[586] one that SCE and the other utilities agreed to.

Moreover, SCE's criticisms are a disservice to the obviously concerted efforts of SCE's subject matter experts to develop the best possible risk estimates under the S-MAP framework. Those S-MAP estimates are at odds with the coarse, broad brush results using the SRA criteria and do not justify SCE's expansive undergrounding proposal.

SCE's attempt to ignore its quantitative results in lieu of a qualitative framework serves the company's incentive to increase rate base to increase profits. Recognizing and correcting for this well-known incentive of investor-owned utilities is the foundation of the Commission's responsibility to protect the public interest.

15.2.5 SCE Places Inadequate Emphasis on Cost-Effectiveness in Its Proposal for How to Spend Ratepayer Money

The foregoing has shown that, in most (perhaps all) locations, covered conductor will be a more cost-effective use of ratepayer funds than undergrounding. Yet, even though covered conductor has been an extremely successful mitigation for SCE, even in its highest risk areas, SCE seeks the Commission's blessing for an approach that would make undergrounding – the most expensive alternative -- the default choice for almost all areas SCE labels as SRAs. SCE admits that its grid hardening proposal was not created with any thresholds for affordability in mind.[587]

[586] *See* Section 5.3.2 above.

[587] Ex. TURN-12-E, pp. 5-6, citing SCE Response to DR TURN-SCE-039, question 2a: "There are no affordability thresholds or constraints specific to the planned grid hardening scope in the referenced volume of testimony."

SCE claims that its approach is justified because of its extreme view that relative risk is irrelevant and only absolute risk should be considered. The extremeness of SCE's position is evident in its response to SPD's pragmatic suggestion in its RAMP evaluation that SPD consider revamping its proposal by focusing 40% of its spending to achieve 85 percent of the proposed risk reduction. SCE labeled this recommendation "irrelevant," claiming that "it is the remaining (i.e. residual) absolute risk that is relevant, not the amount of relative risk that can be bought down by making the limited investment SPD recommends."[588]

SCE's position is out of synch with the Commission's decision-making framework and basic common sense. It is also profoundly insensitive to the importance of ensuring the affordability of essential electric service, a factor that was central to the Commission's recent decision on PG&E's undergrounding proposal, as discussed below.[589]

The Commission has made clear that examination of the tradeoff between costs and risk reduction benefits is central to the Commission's review and obligations in GRCs. In its decision on SCE's 2021 test year GRC, the CPUC explained that "[o]ne of the central tasks in this proceeding is to balance safety and reliability risks with the associated cost to mitigate those

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[588] Ex. SCE-04, Vol. 5, Part 1A, p. 54. TURN's testimony identifies another example of SCE's extreme position, a response to a Cal Advocates data request in which SCE challenged Cal Advocates' question as improperly focused on relative risk, not absolute risk. TURN's expert Mr. Borden explains the fallacy in SCE's response: "In SCE's example, the highest risk circuit mile would have risk that is 9,900 percent greater than all remaining risk combined. Yet, SCE would have the CPUC compel ratepayers to fund the same type of work on all of the other 999 miles if these were considered 'SRA'. This is precisely why cost-effectiveness matters – not to say that no mitigation should ever take place on any of those remaining 999 circuit miles but, in considering whether and how to mitigate risk for those miles, it is necessary to examine cost-effectiveness tradeoffs that allow for both safe and affordable electric service." Ex. TURN-12-E, pp. 14-15 (emphasis in original).

[589] D.23-11-069, p. 278. Even if the Commission finds merit to SCE's emphasis on absolute risk reduction over cost-effective risk reduction, we note that TURN's recommendation reduces the same amount of risk as SCE's proposal, for $2 billion less.

risks."[590] This balance requires prioritizing where and how ratepayer funding is targeted. As the Commission stated in PG&E's 2014 GRC decision:

> Virtually everything a utility does [has]some nexus to safety and can be deemed to have some safety impact, *but the emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent*.[591]

In the decade since that decision, the Commission has devoted considerable resources to requiring utilities to provide RSE calculations, which it has found are "critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds."[592]

In its most recent GRC decision, D.23-11-069, the Commission put these tools and principles into practice in significantly reducing PG&E's undergrounding proposal and directing PG&E to increase the use of covered conductor, reducing the cost of PG&E's grid hardening proposal by $1.72 billion.[593] The Commission explained that PG&E's more expensive proposal would "present challenges for customers regarding affordability"[594] and that the adopted plan "strikes a balance between risk reduction, feasibility, timeliness, and cost containment."[595] By

[590] D.21-08-036, p. 30.

[591] D.14-08-032, p. 28 (emphasis added).

[592] D.21-08-036, p. 38, quoted in PG&E's 2023 GRC decision, D.23-11-069, p. 44. D.23-11-069 also noted the Commission's prior statement that one of the goals of the S-MAP settlement adopted in D.18-12-014 was to "use risk reduction per dollar spent to prioritize projects."

[593] D.23-11-069, p. 273.

[594] *Id.,* p. 278. The decision also stated on page 295: "Costs are a significant concern and . . . the Commission must examine alternatives to mitigate the burden to ratepayers . . .."

[595] *Id.,* p. 273.

directing PG&E to focus its grid hardening efforts on the highest risk locations,[596] the adopted plan reduced more risk than PG&E's proposal at less cost.[597]

Thus, it is clear that SCE is out of step with the Commission's decision-making approach when it dismisses as irrelevant SPD's suggestion in its RAMP evaluation that SCE re-focus its grid hardening program to provide most of the risk reduction benefit at significantly reduced cost. SCE missed an opportunity to develop a more balanced grid hardening proposal that takes the relative benefits of risk mitigation alternatives into account and that recognizes risk reduction must be balanced with affordability.

15.2.6 TURN's Recommendation

15.2.6.1 TURN Recommends that Undergrounding Be Targeted Where It Will Produce the Greatest Benefit and that Covered Conductor Be Used in the Remaining Unhardened HFTD Locations

TURN's recommendation strikes a more reasonable balance between risk reduction and affordability by achieving as much risk reduction as SCE's proposal at approximately $2 billion less cost.

Rather than using SCE's flawed SRAs to determine the appropriate scope of undergrounding, TURN utilizes RSEs calculated under the S-MAP framework.[598] Because of

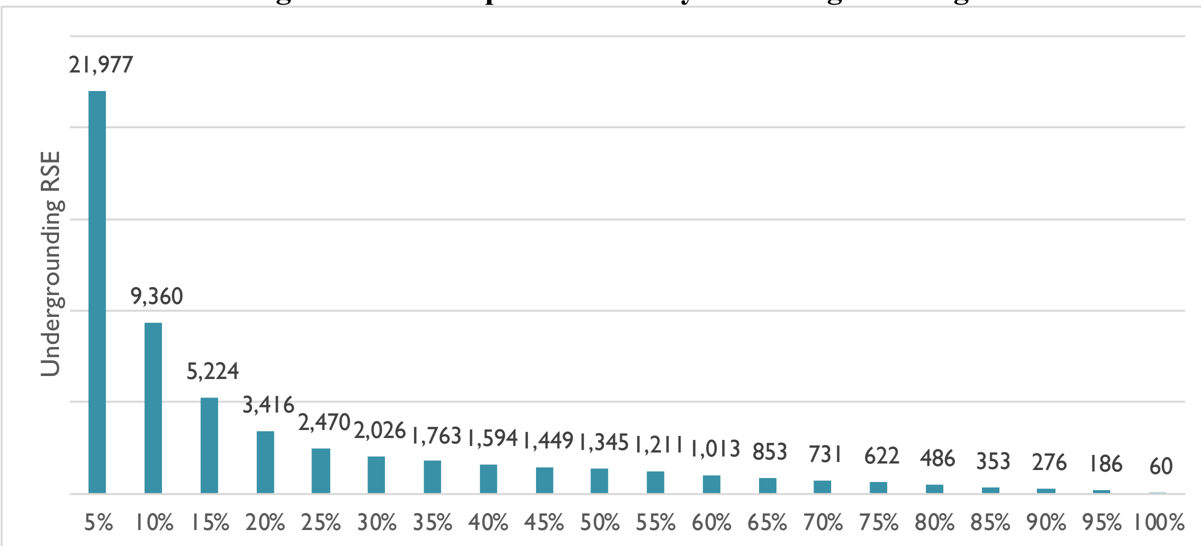
[596] *Id.*, p. 272.

[597] *Id.,* p. 295.

[598] As explained in TURN's testimony, TURN utilized SCE's risk modeling assumptions and outputs presented in its workpapers and aggregated SCE's extremely granular circuit segments (many of which are just a few feet long) into "isolatable segments" which is akin to how circuit segment assets are aggregated into a single "project." This provided a significantly more aggregated analysis that is more realistic for project planning purposes, reducing the approximately 38,000 circuit segment to around 1,900 "isolatable" sections. TURN then calculated RSEs for undergrounding on each isolatable circuit

the significant concentration of risk, these values show a precipitous drop-off in the cost-effectiveness of undergrounding after the top 10-20% of risk, as shown in the figure below.

Figure 11: Risk Spend Efficiency of Undergrounding[599]



While these results would justify scoping undergrounding based on the top 20% of risk, TURN's proposal conservatively determines the appropriate scope of undergrounding based on the number of miles in the top **50%** of risk, which equates to 177 miles.[600]

Accordingly, TURN recommends that 177 miles serve as the maximum number of overhead miles to underground in the 2025-2028 rate case period.[601] The actual miles to be undergrounded up to this cap should be determined by the location-specific analysis discussed in Section 15.2.6.2 below. For the remainder of the HFRA miles that SCE proposes to harden, 1,651 miles in total, TURN recommends covered conductor deployment, in light of its

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section and sorted from highest to lowest undergrounding RSE in order to target the most cost-effective circuits. Ex. TURN-12-E, pp. 27-28.

[599] Ex. TURN-12-E, p. 28, Figure 15.

[600] Ex. TURN-12-E, p. 28.

[601] *Id.,* p. 29.

significantly higher cost-effectiveness and the impressive risk reduction that SCE has already achieved with this mitigation.[602]

TURN's proposal does not rely solely on choosing the most cost-effective alternative; it recognizes that SCE may be able to make a case for deploying undergrounding in certain high risk locations even if undergrounding is not the most cost-effective choice.[603] In addition, TURN supports extending grid hardening to the entire HFTD despite the fact that relative cost-effectiveness of covered conductor may be quite low for many of these areas, given that the HFTD designation indicates an elevated risk of a utility-caused wildfire.[604] These features of TURN's proposal show that SCE incorrectly portrays TURN's recommendation as determined solely by RSEs and relative risk.[605]

TURN's proposal results in the *same* absolute risk reduction as SCE, as shown in the following figure, and a significantly more cost-effective grid hardening proposal overall.

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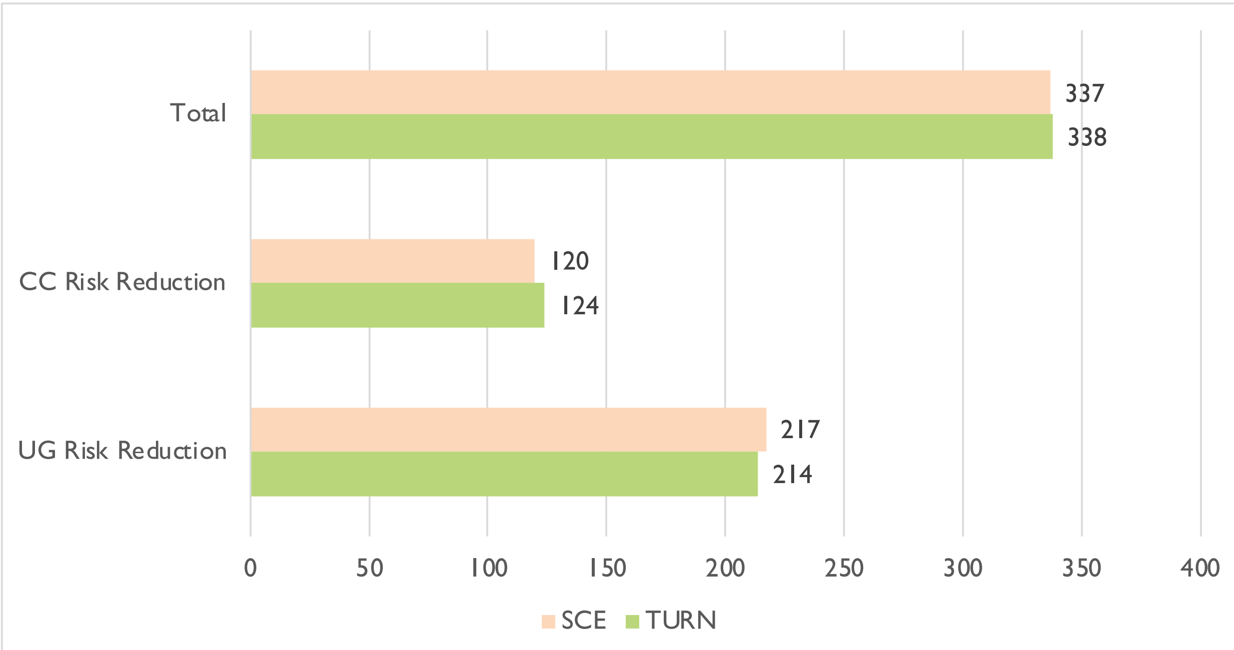
[602] *Id.*

[603] *Id.,* p. 28.

[604] *Id.,* p. 15.

[605] *E.g.,* Ex. SCE-15, Vol. 5, Part 2, p. 10, incorrectly claiming that TURN advocates "rigid adherence to model outputs."

Figure 12: **Absolute Risk Reduction of Grid Hardening Proposals – TURN vs. SCE**[606]



TURN's proposal achieves the same absolute risk reduction with many fewer miles because it targets the circuits with the very highest S-MAP risk scores for undergrounding, which SCE's SRA-based proposal does not.[607]

Overall, TURN's grid hardening proposal is 81 percent more cost-effective than SCE's – with an RSE of 1,603, compared to 888 for SCE.[608] Furthermore, TURN's proposal costs approximately $2 billion less than SCE's over the rate case period for the *same* absolute risk reduction by prioritizing high-risk miles for undergrounding, as determined by the S-MAP framework.[609]

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[606] Ex. TURN-12-E, p. 29, Figure 16.

[607] *Id.*, p. 29.

[608] *Id.,* p. 30.

[609] *Id.*

15.2.6.2 SCE Should Justify Its Use of Undergrounding Through a Location-Specific Analysis

TURN's undergrounding recommendation provides a reasonable maximum number of miles where undergrounding can be expected to be the best system hardening alternative. However, even for the highest risk miles targeted by TURN's proposal, whether undergrounding proves to be the best alternative will depend on location-specific factors, such as the risk drivers and terrain present at the location, which affect the mitigation effectiveness of the competing alternatives and the cost.[610] These factors can vary significantly by project. As the Office of Energy Infrastructure Safety (Energy Safety) stated in its decision on SCE's 2023-2025 Wildfire Mitigation Plan (WMP):

> Mitigation selection should consider a variety of location-specific factors, such as how long it takes to deploy the solution, effectiveness at mitigating particular ignition drivers in a given location, feasibility given terrain and access challenges, and the cost-benefit analysis.[611]

Consistent with Energy Safety's direction, SCE should be required to justify through a location-specific analysis that undergrounding is the best alternative for that location. The analysis should include consideration of the following:

- The location-specific RSE or Cost-Benefit Ratio (CBR)[612] of undergrounding, based on location-specific costs, risk drivers, and risk reduction;

- The location-specific RSE/CBR of covered conductor, based on location-specific costs, risk drivers, and risk reduction and, where REFCL or spacer cable is feasible, the location-specific RSE/CBR of covered conductor with REFCL or spacer cable, based on the same location-specific factors.

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[610] Ex. TURN-12-E, p. 31.

[611] Decision on Southern California Edison Company's 2023-2025 Wildfire Mitigation Plan, Appendix A to Resolution SPD-17, p. 40.

[612] SCE is required to transition to calculation of cost-benefit ratios under the Cost Benefit Approach set forth in D.22-12-027 in its next RAMP submission.

- The RSE/CBR analysis for undergrounding and covered conductor should reflect the "time value of risk" given that undergrounding is usually much more time intensive than covered conductor.
- Consideration of any other location-specific factors that would influence which mitigation is the best alternative.[613]

Based on this location-specific analysis, SCE should determine the best system hardening alternative for each location where undergrounding is considered. In most cases, the best alternative will be the one with the highest RSE or cost-benefit ratio, as the RSE reflects a comprehensive analysis of the risk reduction benefits compared to the costs at the location in question.[614] However, if SCE chooses undergrounding even if it not the most cost-effective alternative, it should be required to explain and document the specific location-specific factor(s) that justify choosing undergrounding and why the RSE/CBR does not adequately reflect such factor(s). For example, SCE could explain that a high risk location has a particularly high tree fall-in risk and that the diminished effectiveness of covered conductor in addressing this driver is not sufficiently reflected in the RSE/CBR. For each undergrounding project that SCE elects to pursue, in the annual accountability report described below, it should document the RSE/BCRs it calculated in choosing among alternatives and, if undergrounding did not have the highest value, its explanation justifying its selection.[615]

If, based on this analysis, SCE decides to pursue less than 177 overhead miles of undergrounding, overhead hardening should be deployed on the miles where undergrounding proved not to be the best alternative.[616]

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[613] Ex. TURN-12-E, pp. 31-32.

[614] *See* Section 15.2.4.4 above.

[615] *Id.*, p. 32.

[616] *Id.*

TURN notes that its proposal in this opening brief differs slightly from TURN's testimony in that TURN would no longer require all undergrounding projects to be in the top 50% of risk. Within the 177-mile cap, TURN would not oppose undergrounding if SCE can demonstrate that a project not ranking in the top 50% of risk warrants this mitigation alternative based on the location-specific analysis. Even though TURN suspects that few projects outside of the 50% threshold will succeed under such an analysis, this modification responds to SCE's claims that TURN's 50% limitation is arbitrary and would prevent SCE from implementing meritorious undergrounding projects.[617]

The Commission should make explicit that no more than a total of 177 overhead miles from 2025-2028 (an average of 44 overhead miles of undergrounding per year) will be funded. If any miles are accomplished beyond this amount, they may not be recorded to any account (memorandum, balancing, etc.) nor may SCE request to establish such an account for this purpose.[618] To the extent that SCE performs less than 177 miles of undergrounding and replaces those miles with overhead hardening, at the end of the rate case period, the difference in costs, based on the forecast unit costs adopted in this decision, should be refunded to ratepayers. Therefore, the one-way balancing account that TURN recommends for all grid hardening expenditures[619] should have a separate one-way sub-account for undergrounding expenditures.[620]

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[617] Ex. SCE-15, Vol. 5, Part 2, pp. 20-21.

[618] Ex. TURN-12-E., p. 32. As TURN's expert Mr. Borden explained, "the proliferation of memorandum and balancing accounts for expenditures that are foreseeable has . . . degraded the affordability of electric rates [for] all the IOUs and weakened Commission oversight of expenditures, particularly for wildfire mitigation . . .." (*Id.*) *See also* Section 38.3 below.

[619] See Section 38.3 below.

[620] Ex. TURN-12-E., pp. 32-33.

The scale of undergrounding proposed by TURN is a reduction from SCE's proposal, but still warrants additional scrutiny given the extraordinary cost and scale of this measure, particularly compared with historical deployment. To this end, SCE should be required to submit an annual accountability report, similar to the report PG&E was required to submit in D.23-11-069.[621] As discussed above, the report should require SCE to provide the results of its location-specific analysis for each undergrounding project it opted to pursue (including incomplete projects) in the preceding year. Consistent with the report PG&E is required to submit, SCE's annual report should also include information on completed undergrounding projects, including costs, unit costs, and overhead to underground conversion ratio information.[622]

15.2.6.3 Summary of TURN's Recommendations

In summary, TURN recommends the following:

- The Commission should approve a grid hardening forecast for the 2025-2028 period of 177 overhead miles converted to undergrounding and 1,651 miles insulated with covered conductor, as shown in the table below:

[621] D.23-11-069, p. 280.

[622] D.23-11-069, pp. 280-283. SCE contends (Ex. SCE-15, Vol. 5, Part 2, p. 22) that such a report is not needed because SCE's program is smaller than PG&E's. However, under TURN's proposal, SCE's undergrounding would still cost as much as $1 billion, and SCE's proposal would cost $3.3 billion. In either case, the factors that D.23-11-069 (p. 280) identified in support of an accountability report – the uncertainty associated with a large scale-up of undergrounding, the significance of the program as a risk reduction proposal, and the significant ratepayer costs involved – all apply here. SCE also argues (Ex. SCE-15, Vol. 5, Part 2, p. 22) that no accountability report is needed because it has provided documentation of its proposed undergrounding projects in its rebuttal testimony. However, that claimed documentation does not provide a comparison of alternatives to undergrounding, including RSEs/CBRs and does not explain why undergrounding should be deployed even when covered conductor would be more cost-effective. Nor does it provide most of the other information required in D.23-11-069.

Table 8: Mileage and Costs of Grid Hardening ($ thousands) – TURN vs. SCE

	Undergrounding				
	2025	2026	2027	2028	Total / Weighted Average
TURN Miles	44	44	44	44	177
SCE Miles	60	150	200	170	580
Unit Cost	*$ 5,083*	*$ 5,677*	*$ 5,717*	*$ 5,687*	*$ 5,632*
TURN Budget	$ 224,903	$ 251,227	$ 252,984	$ 251,633	$ 980,746
SCE Budget	$ 304,954	$ 851,620	$ 1,143,432	$ 966,727	$ 3,266,733
TURN-SCE	**$ (80,051)**	**$ (600,392)**	**$ (890,448)**	**$ (715,095)**	**$ (2,285,986)**
	Covered Conductor				
	2025	2026	2027	2028	Total / Weighted Average
TURN Miles	413	413	413	413	1,651
SCE Miles	850	300	50	50	1,250
Unit Cost	*$ 763*	*$ 778*	*$ 805*	*$ 812*	*$ 770*
TURN Budget	$ 314,921	$ 320,902	$ 332,373	$ 335,247	$ 1,303,442
SCE Budget	$ 648,666	$ 233,289	$ 40,271	$ 40,620	$ 962,845
TURN-SCE	**$ (333,745)**	**$ 87,613**	**$ 292,101**	**$ 294,627**	**$ 340,597**

- For all 2025-2028 undergrounding projects, SCE should conduct the location-specific analysis described in Section 15.2.6.2 and should only implement projects where the analysis shows that undergrounding is the best alternative for that location.

- Ratepayers shall not be required to fund more than 177 overhead miles in 2025-2028. If SCE cannot justify undergrounding of 177 miles under the location-specific analysis and therefore undergrounds fewer miles, overhead hardening should be deployed on those miles. To the extent that SCE performs less than 177 miles of undergrounding and replaces those miles with overhead hardening, at the end of the rate case period, the difference in costs, based on the forecast unit costs adopted in this decision, should be refunded to ratepayers via the one-way balancing account that TURN recommends in Section 38.3 of this brief.

- The one-way balancing account that TURN recommends in Section 38.3 of this brief should have a separate one-way subaccount for undergrounding expenditures.

- The Commission should require SCE to submit an annual accountability report, similar to the report required in D.23-11-069. The report should require SCE to provide the results of its location-specific analysis for each undergrounding project it opted to pursue (including incomplete projects) in the preceding year. Consistent with the report required in D.23-11-069, SCE's annual report should also include information on completed undergrounding projects, including costs, unit costs, and overhead to underground conversion ratio information.

15.2.7 Response to SCE's Rebuttal Testimony

This section responds to arguments presented in SCE's rebuttal testimony that were not addressed in the preceding sections. The need for this new section arises in large part due to the fact that SCE presented new analysis in its rebuttal testimony that was not part of SCE's direct showing.

15.2.7.1 The Results of SCE's New and Opaque 'BCR Analysis' Are Deeply Flawed and Unreliable

SCE's rebuttal testimony claims that its undergrounding proposal is supported by the results of a new, supposedly project-specific "Targeted Undergrounding BCR Analysis" that it presented for the first time in rebuttal testimony.[623] SCE asserts that this analysis shows that, for more than 50% of its proposed undergrounding projects, undergrounding has a higher BCR than an alternative it calls "REFCL/CC ++"[624] -- *i.e.,* covered conductor teamed with REFCL and certain other mitigations.

This result is based on unsupportable assumptions and collapses under even minimal scrutiny. *Even though SCE has successfully deployed covered conductor <u>without REFCL</u> in what it perceived to be its highest risk areas from 2018 through 2023*, SCE's calculations include the assumption that the only variant of covered conductor that should be compared with undergrounding is covered conductor teamed with REFCL. SCE unreasonably assumed that REFCL would be included in every covered conductor project even when SCE estimated the

[623] The output of the analysis is presented in Ex. SCE-15, Vol. 5, Part 2, App. B, pp. B1-B16.

[624] Ex. SCE-15, Vol. 5, Part 2, p. 30.

costs to be infeasibly high.[625] The REFCL costs that SCE included ranged from 0 to $1.3 *billion* per overhead mile, a weighted average of $5 *million* per mile, compared to SCE's unit cost for its proposed deployment of REFCL in this case of about $100,000 per mile.[626] By making the covered conductor alternative unreasonably costly for many projects, SCE skewed the cost-effectiveness comparison in favor of undergrounding.[627]

When TURN corrected just this assumption (i.e., leaving the rest of SCE's analysis unchanged) by limiting REFCL to projects where REFCL's unit cost was less than $200,000 per mile (twice SCE's unit cost forecast in this GRC), covered conductor or covered conductor with REFCL had a higher BCR than undergrounding for 97.5 percent of the miles in SCE's undergrounding proposal – a completely different result from what SCE presented and consistent with TURN's findings in its opening testimony.[628]

Cross-examination revealed another significant flaw – the failure to incorporate SCE's well-established Fast Curve mitigation into the analysis. Fast Curve settings reduce fault energy by increasing the speed by which a relay reacts to faults;[629] they have been widely installed in SCE's HFRA circuits.[630] Fast Curve has a standalone mitigation effectiveness of 40 to 50 percent, is compatible with covered conductor, and does not need REFCL to operate.[631] Despite

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[625] Ex. TURN-20, pp. 1, 4-6.

[626] Ex. TURN-20, pp. 4-6.

[627] *Id.*, p. 5.

[628] *Id.*, pp. 6-8. As discussed below, by presenting its complex new analysis for the first time in rebuttal testimony, SCE left TURN little time to scrutinize SCE's workpapers and make other necessary corrections. *Id.*, pp. 1, 3-4.

[629] Ex. SCE-04, Vol. 5, Part 2A, p. 86.

[630] Tr. Vol. 10, p. 923:9 – 924:5. (Fugere/SCE).

[631] *Id.*, p. 924:16 – 925:7.

Fast Curve's obvious usefulness as a way to significantly increase the effectiveness of covered conductor, SCE left Fast Curve out of the analysis entirely.[632] As a result, the analysis did not include a covered conductor plus Fast Curve option for the high percentage of locations where SCE's calculation of REFCL costs made REFCL infeasible. Had Fast Curve been included, the mitigation effectiveness of the covered conductor alternative would have been higher and TURN's alternative calculations would likely have shown the covered conductor alternative to be more cost effective than undergrounding for even more than 97.5 percent of miles.

Even though TURN had very limited time to examine SCE's complex new quantitative analysis, TURN identified numerous other problems that make the results entirely unreliable, including:

- SCE's rebuttal analysis used more granular cost estimates for covered conductor and REFCL, but for undergrounding SCE used just used an across-the-board average cost[633] even though SCE's direct testimony stated that undergrounding costs can vary "significantly" based on factors such as "population density, topography, permitting and environmental clearances, paving and labor."[634] SCE's failure to do an apples-to-apples comparison of project costs – when this was ostensibly the improvement it tried to make to its S-MAP analysis -- further compromises the reliability of its results.

- SCE's workpapers do not indicate whether the analysis incorporates the time benefit of covered conductor compared to the longer time required for undergrounding deployment.[635]

- SCE's workpapers do not provide calculations showing how SCE converted risk reduction values to dollars,[636] including whether a reasonable value of statistical life (VSL) was used. SPD's RAMP Evaluation Report and TURN's RAMP

[632] *Id.*, p. 981:17-19. This omission is particularly glaring because SCE's direct testimony defined REFCL/CC ++, the alternative that was supposedly being compared with undergrounding, to include Fast Curve. Ex. SCE-04, Vol. 5, Part 1A, p. 46.

[633] Ex. TURN-20., p. 3.

[634] Ex. SCE-04, Vol. 5, Part 2A, p. 19.

[635] Ex. TURN-20, p. 3.

[636] Ex. TURN-20, p. 3.

comments were highly critical of the implied SVL in SCE's S-MAP analysis, which SPD found to be unfavorably high compared to accepted government figures.[637] In future BCR analyses, utilities are required to use the US Department of Transportation VSL as the standard value.[638]

- SCE's analysis divided total REFCL costs only by SRA miles that would benefit from a given REFCL project, rather than dividing them by all miles that would benefit. The result was to unreasonably increase the unit costs of REFCL while not accounting for additional benefits of the project. This inaccurately added to the cost of the covered conductor alternative, once again skewing the analysis in favor or undergrounding.[639]

Notably, SCE did not use this rebuttal analysis or any similar comparative project-specific analysis as part of its process for deciding the scope of its undergrounding proposal. In fact, SCE admitted that its proposal is not based on any project-specific analysis examining whether undergrounding was the most cost-effective alternative.[640] Thus, the Commission should give no weight to SCE's rebuttal analysis, not only because of its dubious assumptions and results, but also because it is irrelevant to how SCE arrived at its undergrounding proposal.

SCE's rebuttal also cites another conclusion from its Undergrounding BCR Analysis, that claims that benefits exceed costs for a majority of its proposed projects and 447 out of 580 proposed miles.[641] However, as discussed above, SCE's supposed project-specific analysis of

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[637] SPD Staff Evaluation Report on SCE's 2022 RAMP, A.22-05-013, Nov. 10, 2022, pp. 18-19, made a part of the record of this case by ALJ ruling. Tr. Vol. 10, p, 996:20 – p. 997:3 (hereinafter "SPD RAMP Evaluation). *See* Section 5.3.3 above.

[638] D.22-12-027, p. 35.

[639] Ex. TURN- 803, SCE response to TURN DR 128, Question 3(c)(i), which confirmed TURN's suspicion described in Ex. TURN-20, p. 5 and fn. 18.

[640] Ex. TURN-12-E, p. 6 and fn. 6.

[641] Ex. SCE-15, Vol. 5, Part 2, p. 18. SCE (*id.*, pp. 17-18) also claims that the benefit-cost ratios (BCR) presented in Ex. TURN-4 show that SCE's undergrounding proposal would provide more benefits than costs. However, SCE ignores the cautions stated in TURN's testimony about how to use the BCR figures, including examining the particular calculation methodology to determine whether benefits are accurately estimated. (Ex. TURN-4, p. 15). As both SPD and TURN pointed out in the RAMP, SCE's S-MAP calculations exaggerate risk reduction benefits because they assume an unreasonably high value of a statistical life (SPD RAMP Evaluation, pp, 18-19 and Att. 3 thereto (TURN's comments), pp. 10-14), a

the benefits and costs of its undergrounding proposal is unreliable because SCE did not use project-specific undergrounding costs and likely used inflated values to measure the safety benefits of undergrounding, thereby exaggerating its benefits. Furthermore, since covered conductor is almost always *more* cost-effective than undergrounding, covered conductor also has benefits that exceed costs, and to a much greater degree than undergrounding.

Therefore, nothing in the record disputes that covered conductor is a highly effective mitigation and overwhelmingly more cost-effective than undergrounding. (See Section 15.2.2). Given this choice between two desirable alternatives, SCE should not burden ratepayers with a less cost-effective option unless SCE has provided a good reason for doing so based on location-specific considerations, an outcome that is only achieved under TURN's recommendations.

15.2.7.2 SCE Wrongly Argues that TURN's Proposal Deprives SCE of the Ability to Apply Subject Matter Expertise and Judgment

SCE asserts that TURN's recommendations would require SCE to "rely solely on the outputs of quantitative risk modeling data instead of also applying judgment, local knowledge, and subject matter expertise."[642]

SCE presents a blatantly false dichotomy. As TURN showed in Section 15.2.4.4 above, the S-MAP framework requires utilities to use their best subject matter expertise and judgment to

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problem that SCE did not correct in its GRC calculations, but that SCE will have to fix in its next RAMP and GRC per D.22-12-027, p. 35. *See also* Section 5.3.3 above. Thus, it is unreasonable to conclude from SCE's RSEs (and CBRs derived from those RSEs) that SCE's undergrounding program is cost effective.

[642] Ex. SCE-15, Vol. 5, Part 2, p. 10. p. 16. In a similar vein, SCE (*id.,* pp. 10, 16) claims that TURN's recommendation is based solely on RSE. But then SCE contradicts itself and recognizes that TURN's proposal takes other factors into consideration. (*Id.,* pp. 16-17, fn. 36). As discussed in Section 15.2.6, while TURN recommends that relative cost-effectiveness be a key factor in determining which grid hardening alternative is deployed, TURN's proposal would allow SCE to make the case for undergrounding even when it is not the most cost-effective mitigation in a location.

supplement the available data as the utility finds necessary. Thus, it is simply incorrect for SCE to suggest that quantifying that expertise means that judgment is not being used. The important benefit of the S-MAP framework quantifications is to provide a transparent vehicle for the CPUC and parties to evaluate the data *and judgment* that inform the utility's risk assessments. Without such quantifications, SCE's decisions are based on a virtually unreviewable black box exercise of discretion by SCE managers, who work for an investor-owned utility with a strong incentive to build rate base. The quantification effort required by the S-MAP framework are an important way to ensure that utility choices are accountable and consistent with the public interest rather that promoting the shareholders' financial interest.

Moreover, TURN's recommendations would not dictate where SCE can move its wires underground.[643] TURN would leave that choice to SCE, within the constraints of the 177-mile cap. As discussed, that cap is based on the output from SCE's S-MAP risk modeling showing that the top 50% of remaining risk on SCE's system is found in 177 miles. Provided that SCE can justify an undergrounding project through the location-specific analysis described in Section 15.2.6.2, SCE would determine where undergrounding is appropriate based on its expertise and judgment (documented in TURN's recommended accountability report), including if warranted in a location outside the top 50% of risk.

[643] As noted in Section 15.2.6.2, TURN has modified its proposal in this opening brief to no longer require that <u>all</u> underground miles be in the top 50% of risk.

15.3 Emergent Technology And Inspections And Remediations

15.4 PSPS And Other Wildfire Activities

16. T&D OTHER COSTS AND OTHER OPERATING REVENUE

16.1 T&D Other Costs

16.2 T&D Other Operating Revenues

17. CUSTOMER SERVICE OPERATIONS

17.1 Billing And Payments

TURN sponsored testimony addressing Billing and Payments in Ex. TURN-10. TURN has since reached a mutually agreeable resolution for the forecasts related to Billing and Payments. TURN's recommendations are reflected in the "Stipulation of TURN, Cal Advocates, and SCE on Billing Services GRC Activity, Credit and Payment Services GRC Activity, and Billing and Payments Capital," which has been admitted into evidence as Ex. SCE-25. TURN urges the Commission to adopt all of the individual recommendations included in Ex. SCE-25, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

17.2 Customer Contacts

TURN sponsored testimony addressing Customer Contacts in Ex. TURN-10. TURN has since reached a mutually agreeable resolution for the forecasts related to Customer Contacts. TURN's recommendations are reflected in the "Stipulation of TURN, Cal Advocates, and SCE on Customer Contacts BPE," which has been admitted into evidence as Ex. SCE-29. TURN urges the Commission to adopt all of the individual recommendations included in Ex. SCE-29, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

17.3 Customer Service Re-Platform

17.4 Customer Service-Related Other Operating Revenues

17.5 Billing Practices And Policies

18. BUSINESS CUSTOMER SERVICES

18.1 Business Customer Services

TURN sponsored testimony addressing Business Customer Services in Ex. TURN-10. TURN has since reached a mutually agreeable resolution for the forecasts related to Business Customer Services. TURN's recommendations are reflected in the "Stipulation of TURN, Cal Advocates, Walmart, and SCE on Business Customer Services BPE and Communication, Education, and Outreach BPE," which has been admitted into evidence as Ex. SCE-26. TURN urges the Commission to adopt all of the individual recommendations included in Ex. SCE-26, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, Walmart, and SCE in its entirety.

18.2 Communications, Education, And Outreach

19. CUSTOMER PROGRAMS AND SERVICE

19.1 Customer Experience Management

19.2 Customer Programs Management

TURN sponsored testimony addressing Customer Programs Management in Ex. TURN-

10. TURN has since reached a mutually agreeable resolution for the forecasts related to Customer Programs Management. TURN's recommendations are reflected in the "Stipulation of TURN, Cal Advocates, and SCE on Customer Programs Management GRC Activity," which has been admitted into evidence as Ex. SCE-28. TURN urges the Commission to adopt all of the individual recommendations included in Ex. SCE-28, recognizing that they constitute an integrated agreement supported by TURN, Cal Advocates, and SCE in its entirety.

20. BUSINESS CONTINUATION

20.1 Planning, Continuity, And Governance

20.2 All Hazards Assessment, Mitigation and Analytics -- Seismic Resiliency for Non-Electric Facilities

The Commission should adopt TURN's forecast for SCE's seismic retrofitting activities at non-electric facilities.

SCE's "All Hazard Assessment, Mitigation and Analytics" capital expenditures forecast includes the Seismic Resiliency Program that covers, among other things, the seismic retrofits for the utility's "non-electric facilities," primarily offices and operational buildings supporting power delivery.[644] SCE's forecasts for the Test Year 2025 GRC period include assessment activities that the utility contends are based on historical costs incurred between 2016 and 2021,[645] and the mitigation activities at specific facilities. For the latter category, SCE states that its "project costs are based on a per square foot unit estimate provided by a third party engineering firm considering the requisite materials, construction and supporting activities by building type," with the resulting estimate then applied to the planned mitigation projects at non-

[644] Ex. SCE-04, Vol. 1, pp. 21-23 and 46.

[645] *Id.*, p. 40.

electric facilities from 2023-2028.[646] On this basis, SCE forecasts $23.286 million for 2023, $28,400 million for 2024, and $31.400 million for 2025 for the costs of assessing and retrofitting non-electric facilities.[647]

TURN's testimony recommended that the Commission determine that SCE has failed to demonstrate the reasonableness of the project-specific forecasts that underlie the utility's overall forecast.[648] Though SCE cites several factors that it claims fed into each project's forecast, and its overall forecast purports to be a sum of numerous project-specific forecasts, its testimony and workpapers did not include any material explaining the basis for each of the project-specific forecasts. Instead, SCE relies heavily on a National Institute of Standards and Technology (NIST) model that it claims permitted it to develop a "better" cost estimate for each model based on its determination that "average seismic retrofit costs can be expected to be $147.00 per square foot."[649]

There are numerous problems with SCE's purported reliance on the NIST model as set forth in the "working paper" SCE provided as the basis for the model's application here. For example, SCE's direct testimony described the NIST model as supporting the assumption that "average seismic retrofit costs can be expected to be $147.00 per square foot."[650] But the working paper that sets forth the NIST model results describes two different average cost figures that would apply given SCE's portfolio of buildings: $91 per square foot to retrofit them to the

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646 *Id.*

647 *Id.*, p. 46, Table II-8.

648 Ex. TURN-15-E2, p. 32.

649 Ex. SCE-04, Vol. 1, p. 30.

650 Ex. SCE-04, Vol. 1, p. 50.

"life safety" standard, and $147 per square foot to retrofit them to the "immediate occupancy" standard.[651] Most of SCE's seismic retrofit projects performed in recent years and forecasted for the TY 2025 GRC period are being done to the lower cost "life safety" performance objective.[652]

The working paper's rather candid assessment of its own limitations is also an indication that it is not an appropriate basis for adopting SCE's forecast here. SCE's consultant tested the NIST model against three SCE retrofit projects, and described its findings as follows:

> The estimates were reasonably close: the equation estimated all three square-foot costs (at least as far as SCE currently knows them) within ± 34%. **That modest margin is probably partly due to luck, but provides some validation anyway.** SCE could realistically use the NIST model ... for preliminary budgeting purposes.[653]

Later in the working paper, SCE's consultant raised additional "cautions" about the underlying NIST model becoming less reliable as the underlying data grow older (it is pre-1993 data), and stated, "The limited tests we performed of the model's accuracy are **somewhat reassuring, but the agreement could be accidental**."[654] Given the consultant's rather tepid endorsement of its own product, the Commission should find that SCE has not demonstrated the reasonableness of using the average square foot results calculated using the NIST model for purposes of developing a forecast for non-electric seismic retrofit costs here.

SCE's testimony states that the utility has completed 28 seismic retrofits of non-electric facilities since its 2021 GRC.[655] The average recorded cost of these projects is approximately

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[651] Ex. SCE-04, Vol 1-WP, p. 76.

[652] Ex. TURN-15-Atch1, Attachment 14 (SCE Responses to TURN DR 63-1 and 63-2).

[653] Ex. SCE-04, Vol. 1-WP, p. 76 (emphasis added)

[654] Ex. SCE04, Vol. 1-WP, p. 78 (emphasis added).

[655] Ex. SCE-04, Vol. 1, p. 50.

$57 per square foot.[656] TURN recommends that the Commission should rely on the recorded average cost of these completed projects rather than the much higher estimated average cost figures set forth in SCE's testimony and workpapers, or the $84 per square foot implied by SCE's proposed forecasts.[657] TURN's testimony explains how the use of the $57 per square foot figure results in the forecasts below for 2023, 2024 and 2025, figures that are approximately one-third lower than SCE's forecasts.[658]

$,000	2023 forecast	2024 forecast	2025 forecast
SCE Forecast	$23,296	$28,400	$31,400
TURN Forecast	**$15,966**	**$19,549**	**$21,587**
Difference	$7,330	$8,851	$9,813

SCE's recorded 2023 costs for the seismic resiliency program for its non-electric facilities amounted to $15.222 million, a figure much closer to the forecast developed under TURN's method ($15.966 million) than to SCE's 2023 forecast ($23.296 million).[659]

SCE's rebuttal presented no substantive or well-founded challenge to TURN's recommendation. The utility doubled-down on its reliance on the NIST model and SPA Risk

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[656] Ex. TURN-15-E2, p. 33.

[657] *Id.*

[658] *Id.* For these activities, TURN recommends that the authorized amounts for purposes of establishing the post-test year revenue requirements be determined consistent with TURN's recommendations for post-test year ratemaking as set forth in Ex. TURN-17 (Testimony of Cathy Yap) and Section 41 of this brief, rather than based on project-specific budgets as SCE has proposed.

[659] Ex. TURN-102, p. 1 (2023 recorded figure); Ex. TURN-15-E2, p. 33 (for TURN 2023 forecast); and Ex. SCE-04, Vol. 1, p. 46, Table II-8 (for SCE 2023 forecast).

LLC's review thereof, but without acknowledging, much less addressing the significant caveats the analyst had raised in its working paper.[660]

SCE also asserted that "TURN's funding levels would negatively affect the safety of our workforce and reliability of service to our customers."[661] The Commission should dismiss such claims as contradicted by SCE's own 2023 spending level. Surely SCE is not suggesting that by spending slightly below TURN's 2023 forecast (and $8 million below its own 2023 forecast), the utility was negatively affecting safety and reliability.[662] SCE's claim is also belied by the memorandum account that was adopted in the 2021 GRC, but has remained unused since then.[663] SCE cannot seriously expect the Commission to believe that adopting TURN's forecast here (with a unit cost of approximately double that adopted in the 2021 GRC) is a threat to safety or reliability, when SCE's spending in the 2021-2024 period stayed within Commission-authorized amounts despite those amounts being far less than the utility's 2021 GRC forecasts for that period.

Similarly, the Commission should disregard SCE's criticism of TURN for having derived a single average cost per square foot rather than one that reflects differences between "structural" and "non-structural" mitigations.[664] SCE's direct testimony cited a single cost per square foot,

[660] Ex. SCE-15, Vol. 1, pp. 13-15.

[661] *Id.*, p. 10.

[662] Again, SCE forecasted $23.296 million for 2023, but spent $15.222 million.

[663] In D.21-08-036 the Commission adopted a unit cost of $28.66 per square foot for seismic retrofits at non-electric facilities, which reduced SCE's forecast by approximately $10.745 million. The Commission also provided SCE with a new memorandum account to track above-authorized spending should there be any. D.21-08-036, p. 332-333. There were none: In the current GRC, SCE reports that it has recorded no incremental amounts in this memorandum account through the end of 2023, and does not anticipate recording any amounts in 2024. Ex. SCE-18, Vol. 1, p. 45.

[664] Ex. SCE-15, Vol. 1, pp. 11-12.

claiming "average seismic retrofit costs can be expected to be $147.00 per square foot."[665] And though it claimed the utility includes both "structural and non-structural mitigations" in developing its "unique project cost estimations," the project cost estimations provided in the workpapers included no information that would permit the Commission to distinguish between structural and non-structural mitigations. Rather, for the projects specified for 2023 or 2024 work, a single annual amount is provided without any information explaining how the specific amount was derived. And for most of the 2024 forecast and all of the 2025 forecast (other than assessment work), the forecast is a single lump sum not attributable to any particular project.[666] SCE should not be heard to criticize TURN for a lack of project-level specificity in the development of its forecast when TURN's forecast is not materially different in this regard than the material SCE included in its direct showing.

665 Ex. SCE-04, Vol. 1, p. 50.

666 Ex. SCE-04, Vol. 1-WP, p. 63.

21. EMERGENCY MANAGEMENT

21.1 Training, Drills And Exercises

21.2 Emergency Preparedness And Response

21.3 Storm Response

22. CYBERSECURITY

22.1 Cybersecurity Delivery

22.2 Grid Modernization Cybersecurity

22.3 Software License & Maintenance

23. PHYSICAL SECURITY

24. GENERATION

24.1 Hydro

24.1.1 Hydro Capital

TURN's testimony recommended a series of adjustments to SCE's proposed hydro capital expenditure forecast. These adjustments include moving the assumed date of issuance for FERC licenses to later years in order to reflect SCE's revised expectations, removing capital additions from the Results of Operations model for projects that are delayed, harmonizing start dates for Big Creek area recreation projects with a 2007 Settlement Agreement, assuming a two year delay in capital expenditures relating to the Borel project, and adjusting the cost of the Big Creek 4 Unit 1 generator rewind to reflect a lower escalation in materials costs.[667] In addition, TURN's testimony recommended that ratepayer responsibility for San Gorgonio decommissioning costs should be reduced by at least $10 million since ratepayers have

[667] Ex. TURN-13-E, pp.23-25.

repeatedly paid for forecasted activities over the last five rate cases that were approved but not undertaken.[668]

SCE's rebuttal testimony made a series of concessions to TURN's positions with respect to delays in FERC licensing and decommissioning activities and Big Creek generator rewind costs.[669] These concessions result in a forecast for 2024-2028 that is identical to TURN. The following table provides a comparison of the original and revised capital expenditure forecasts provided by TURN and SCE:[670]

HYDRO CAPITAL EXPENDITURES							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**TOTAL**
SCE initial application	**78,701**	**79,536**	**67,191**	**75,119**	**77,279**	**67,363**	**471,520**
SCE rebuttal + errata to 2023 recorded	**52,051**	**94,103**	**83,503**	**73,785**	**43,254**	**59,382**	**406,077**
TURN direct/errata testimony	**36,775**	**94,103**	**83,503**	**73,785**	**43,254**	**59,383**	**390,803**

Since the revised forecast by SCE and TURN for 2024-2028 is identical, the Commission need not resolve any of the underlying factual disputes related to these forecasts presented in testimony.

The remaining dispute relates to the treatment of capital expenditures at San Gorgonio. TURN's testimony noted that SCE's forecast of decommissioning costs for San Gorgonio increased from $6.6 million (in the last GRC) to $41.212 million (in the current GRC).[671] One driver of the increase was damage to a significant portion of the project in the Apple Fire of 2020, which occurred in the middle of litigating SCE's last GRC but was not brought to the Commission's attention until that case was completed.[672] SCE first began asking for cost recovery for San Gorgonio decommissioning in the 2009 GRC, received authorization to charge

[668] Ex. TURN-13-E, p.25.
[669] Ex. SCE-16, pp.39, 43-44.
[670] Ex. TURN-13-E, p. 6, Table 1; Ex. SCE-16, p.36; Ex. SCE-40, p.A43.
[671] Ex. TURN-13-E, p.45.
[672] Ex. TURN-13-E, p.46.

customers for these costs in five successive GRCs, and collected approximately $10.6 million from ratepayers over this period for work that was not performed.[673]

To address the systematic overcollection of costs from customers since 2009 that were not actually incurred, TURN recommends that the Commission reduce overall ratepayer cost responsibility for San Gorgonio decommissioning by $10 million.[674] This disallowance would not penalize SCE for poor performance but instead enforces a modicum of ratepayer fairness given the long history of forecasted costs being collected in rates, not spent on decommissioning, and instead retained by SCE's shareholders. If the Commission adopts TURN's recommendation, SCE would still be able to collect funding in this GRC to support actual anticipated decommissioning activities to be performed over the current cycle. But SCE would be forced to reimburse ratepayers for 15 years of overcollections that exclusively benefited its shareholders. The Commission should not allow SCE, or any utility, to repeatedly collect funds from its customers for projects that are repeatedly delayed and do not occur. The $10 million disallowance would represent an equitable outcome given the historic benefits to shareholders and the costs already imposed on ratepayers.

24.1.2 Hydro O&M

SCE's application and direct testimony proposed an O&M revenue requirement of $53.475 million in the 2025 test year.[675] TURN's testimony recommended two separate adjustments to the SCE forecast. First, TURN proposed using data from 2016-2020 (instead of 2018-2020) to develop base year hydro non-labor O&M.[676] This recommendation reduces test

[673] Ex. TURN-13-E, p.46; D.21-08-036, p.353.
[674] Ex. TURN-13-E, p.47.
[675] Ex. SCE-05v1, p.48.
[676] Ex. TURN-13-E, p.21

year O&M by $0.622 million. Second, TURN recommended reducing test year O&M by an additional $0.289 to reflect delays in new federal licenses for the Big Creek and Kaweah facilities.[677] TURN's total adjustments proposed to Hydro O&M are $0.911 million ($2022).[678]

TURN's first recommendation is to use a 5-year historic period from 2016-2020 as the basis for SCE's non-labor O&M forecast rather than the 2018-2020 period relied upon by SCE. TURN witness Monsen explained that costs between 2018-2020 reflect the highest annual values when compared to a longer historical lookback (2014-2022) and therefore do not represent a reasonable starting point.[679] As an alternative, TURN recommends a 5-year historic period that runs from 2016 through 2020 that yields a $0.622 million reduction compared to SCE's proposal.[680]

In rebuttal testimony, SCE argues that the 2018-2020 historical timeframe is appropriate given storm events in 2021-2022 and asserts that any reliance on 2016-2017 recorded data for purposes of assessing the reasonableness of the test year forecast is "outside the scope of this GRC" and would require SCE to spend significant time to "fully analyze and conduct discovery on the data."[681] In support of this claim, SCE cites prior Commission decisions that authorize the GRC rate case plan.[682] None of these decisions have any bearing on the ability of an intervenor to propose that the Commission rely on a different historical time period to develop a base year forecast. Moreover, SCE had a fair opportunity to conduct discovery on TURN's recommendation but failed to do so.

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[677] Ex. TURN-13-E, pp.25-26.
[678] Ex. TURN-13-E, p.6, Table 2.
[679] Ex. TURN-13-E, p.22.
[680] Ex. TURN-13-E, p.23.
[681] Ex. SCE-16, pp.23-24.
[682] Ex. SCE-16, p.24, footnote 69.

SCE further argues that the use of 2016 and 2017 data would be inappropriate because these years involved water runoff that "is lower than historical averages", resulted in less operation, and decreased the need for equipment repairs and replacement parts.[683] Data provided by SCE in response to TURN discovery does not support this contention. The following table shows annual hydro generation between 2016-2022:[684]

SCE hydro generation (MWh) per year	
	Annual generation (MWh)
2016	3,711,821,650
2017	5,806,449,076
2018	3,503,918,894
2019	4,308,160,247
2020	2,159,999,863
2021	1,727,229,059
2022	2,565,762,550
TURN period average (2016-2020)	3,898,069,946
SCE period average (2018-2020)	3,324,026,335
Average (2016-2022)	3,397,620,191
Average (2016-2017)	4,759,135,363

As shown in this table, actual generation from the SCE hydro system over the period selected by TURN (2016-2020) is higher than during the period selected by SCE (2018-2020). Moreover, average generation during the 2016-2017 timeframe is greater than the long-term average (2016-2022), the average during SCE's proposed timeframe (2018-2020) and the longer time frame proposed by TURN (2016-2020). This data categorically disproves SCE's claim that

[683] Ex. SCE-16, p.24.
[684] Ex. TURN-709, SCE response to TURN Data Request 117, Q1.

its hydro facilities operated less during 2016 and 2017 than in subsequent years. The Commission should therefore reject SCE's unfounded critique and adopt TURN's recommended use of the 2016-2020 period for determining base year O&M.

TURN's second recommended adjustment reduces the adders SCE applies to its base labor O&M forecast for work relating to Big Creek and Kaweah, facilities that SCE assumed would be receiving new licenses from the Federal Energy Regulatory Commission (FERC) in 2023. As shown in TURN's testimony, SCE assumed that there would be additional O&M in 2025 to address relicensing conditions adopted in 2023.[685] In response to discovery, SCE acknowledged delays that are expected to lead to the Big Creek license being issued in 2024 and the Kaweah license issued in 2025.[686] SCE's response specifically states that the Kaweah license issuance date is 2025 and that "FERC is still completing their National Environmental Policy Act (NEPA) process and the License is expected within one year following the completion of the NEPA process."[687]

In rebuttal, SCE agrees that the Big Creek license is likely to be delayed to 2024 and makes a $0.152 million reduction to its 2025 forecast of new license implementation activities.[688] SCE contests TURN's proposal to reduce the 2025 forecast by an additional $0.136 million based on two critiques. First, SCE asserts that its original testimony and workpapers forecasted that the Kaweah license will be issued in 2024 and there is "no reason to believe" the date will slip.[689] This claim is flatly contradicted by SCE's response to TURN data requests acknowledging a likely 2025 license renewal date, a fact that SCE ignores and does not even

[685] Ex. TURN-13-E, p.52.
[686] Ex. TURN-13-E, p.28; Ex. TURN-13-Atch1, SCE response to TURN Data Request 52, Q2a.
[687] Ex. TURN-13-Atch1, SCE response to TURN Data Request 52, Q2a, Attachment (Note 2).
[688] Ex. SCE-16, p.25.
[689] Ex. SCE-16, p.25, *citing* SCE's original workpapers.

address in its rebuttal.[690] Second, SCE argues that some of the costs identified by TURN will not be affected by the delay in issuing new licenses for either Kaweah or Big Creek.[691] However, SCE's own workpapers show that some of these costs are attributable to "new license compliance for Kaweah" and that these costs can only be incurred after the license is received. [692] This fact undermines the claim that delays in the receipt of a new FERC license will not affect the timing of these costs. The Commission should reject SCE's efforts to limit the downward adjustment to 2025 O&M costs given its acknowledgement regarding the Kaweah delays.

In light of these facts, the Commission should adopt TURN's full set of adjustments to the hydro O&M expense forecast for 2025.

24.2 Fossil Fuel (Including Mountainview and Peakers)

24.2.1 Mountainview Capital

TURN's testimony identified several capital projects proposed for the Mountainview generation plant that were not adequately supported by SCE in its application. TURN recommends adjusting the capital expenditure forecast through 2028 to remove three capital projects, reduce the recoverable cost for the Inlet Flow Distribution Grids by 25%, and recover costs for the Turbine Generator Improvement Program in a one-way balancing account with excess costs tracked in a memorandum account. TURN's proposals result in a net reduction, relative to SCE's forecast, for 2023-2028 of $17.692 million.

A summary of TURN's adjustments is shown in the following table:[693]

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[690] Ex. TURN-13-Atch1, SCE response to TURN Data Request 52, Q2a, Attachment (Note 2).
[691] Ex. SCE-16, p.25.
[692] Ex. TURN-13-E, p.52, Figure 9 and p.54, Table 24 (See "License Compliance – WO Hydro (Recurring Studies, New License Compliance for Kaweah").
[693] Ex. TURN-13-E, p.9, Table 3. The original table was modified to include recorded 2023 capital expenditures in place of SCE's forecast for that year. SCE provided recorded 2023 data for Mountainview in Ex. SCE-16, p.54.

Mountainview Capital Expenditures - TURN adjustments to SCE forecast							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
SCE Total Mountainview Capex	10,998	7,644	18,295	19,151	17,811	7,976	81,875
less TURN Adjustments							
Disallow CO Catalyst Replacement	-	-	-	-	-	(1,900)	(1,900)
Require Memo Account for Turbine/Generator Improvement Program	-	-	-	-	-	-	-
25% Reduction in Costs for HRSG Inlet Flow Distribtion Grids	-	(100)	(850)	(650)	-	-	(1,601)
Disallow Turbine Control and BCS Project	-	-	-	-	(3,600)	(4,272)	(7,872)
Disallow GR Variable Load Path Project	-	-	-	(800)	(5,519)	-	(6,319)
Subtotal Impacts of TURN Recommendations	-	(100)	(850)	(1,450)	(9,119)	(6,172)	(17,692)
SCE Total Mountainview Capex after TURN Adjustments	**10,998**	**7,544**	**17,444**	**17,700**	**8,692**	**1,804**	**64,184**

The adjustments proposed by TURN are described in the following sections.

24.2.1.1 CO Catalyst Bed

SCE proposes to replace the Carbon Monoxide (CO) catalyst bed on Unit 3A and 3B at Mountainview in 2028. The catalyst is used to CO control emissions at the plant. SCE forecasts the costs of this project at $1.9 million.[694] While TURN agrees that Mountainview Unit 3 should meet all applicable emissions limits, SCE has not demonstrated that the catalysts are likely to require replacement within this GRC cycle. Due to this uncertainty, TURN recommends that the Commission decline to authorize this capital project and direct SCE to establish a memorandum account that can be used to track catalyst bed replacement costs if needed.[695] Any costs tracked in the memorandum account can be submitted for review in the next GRC.

Although Mountainview is currently meeting emissions requirements, SCE justifies the project based on an assessment performed by outside consultants (Environex).[696] A review of the Environex report does not support the claim that catalyst replacement is necessary, or even likely, in 2028. SCE asserts that replacement in 2028 is appropriate because the report finds that the Catalysts are only expected to "provide the required conversion through the next five

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[694] Ex. SCE-05v1, pp.232-233.
[695] Ex. TURN-13-E, p.7.
[696] Ex. SCE-05v1, p.232; Ex. TURN-13-E, p.58; Ex. TURN-13-E-Atch1, SCE response to TURN Data Request 80, Q9.

years".[697] But the actual report provides life projections of ">5" years for the Catalysts in Units 3A and 3B and notes that projections "over five years have an increasing degree of uncertainty" due to a variety of factors.[698] A plain reading the report shows that Environex found the Catalysts are expected to perform for at least five years, meaning that the catalysts could continue to operate successfully well beyond that time horizon. Environex further recommended remedial actions to improve catalyst performance and regular testing "to account for any changes in operation and monitor catalyst performance."[699]

During cross-examination, SCE witness Maddox claimed that the catalysts would be replaced in 2028 regardless of whether they are performing well.[700] This position is not reasonable and could result in the unnecessary replacement of catalysts that are performing within desired specifications. If remedial actions and testing results demonstrate that the catalysts can operate past 2028, SCE should not be encouraged to prematurely replace these components.

TURN's recommendation to remove the catalyst replacement costs from the forecast is designed to prevent against wasteful spending. Recognizing that there is uncertainty, TURN proposes to allow SCE to establish a memorandum account that could be used to track these costs if replacement is necessary and prudent. This approach is reasonable in light of the dual objectives of safe operations and cost-minimization.

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[697] Ex. SCE-16, p.57.
[698] Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q. 24.c.iv, Attachment, p.30.
[699] Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q. 24.c.iv, Attachment, p.30.
[700] Hearing Transcript, May 7, 2024, pp.483-484.

24.2.1.2 Turbine Generator Improvement Program

SCE's forecast includes costs for a major inspection and refurbishment of all four gas turbines at Mountainview, two steam turbines and their associated generators.[701] The cost of this project is estimated to be $28.296 million and represents the largest capital project included in SCE's Mountainview forecast.[702] According to SCE witness Maddox, SCE accelerated the duration of this project from four years to slightly over two years after the submission of direct testimony in this proceeding but made no changes to the forecasted costs.[703]

TURN's testimony recommends establishing a one-way balancing account set at SCE's cost forecast and a memorandum account for tracking costs in excess of any authorized capital expenditures for this project.[704] If costs are less than SCE's forecast, the overcollection would be returned to ratepayers. Since the work is now slated to occur over a shorter period of time (2+ years vs. original forecast of 4 years), total project costs could be lower than originally forecast. Approving an overly generous forecast would benefit SCE's shareholders through higher collections from ratepayers during the GRC cycle.

TURN's alternative would allow SCE to proceed with the project while ensuring that any cost savings are flowed through to customers during the current GRC cycle. To the extent that SCE's costs exceed the cap in the one-way balancing account, TURN's approach would allow SCE to track the overage and seek review of these costs in the next GRC. The Commission should adopt this treatment to better align the interests of ratepayers and shareholders.

24.2.1.3 HRSG Inlet Flow Distribution Grids

SCE proposes to install new Inlet Flow Distribution Grids in all 4 Heat Recovery Steam Generators (HRSGs) at Mountainview. The cost of this project is forecasted to be $6.401 million with work occurring between 2024-2026.[705] Although Mountainview originally had inlet flow distribution grids when it was built, SCE management decided to remove them in 2007 (shortly after the facility was completed) due the failure of key components of the system and chose not re-install new grids based on the mistaken assumption that the plant would operate primarily as a baseload resource with limited ramping.[706] In 2019, Mountainview began experiencing an increase in HRSG tube failures which SCE decided could be remedied through the re-installation of the inlet flow distribution grids.[707]

TURN recommends that SCE shareholders be assigned 25% of the cost of new inlet flow distribution grids.[708] This recommendation is based on the fact that SCE intentionally removed the original grids, did not attempt to repair them, and failed to demonstrate that it sought any remedies against the vendor that supplied the defective materials.[709] Moreover, SCE ignored the ample evidence that state policy was driving the accelerated growth of intermittent renewable energy in a manner that would necessitate additional cycling of thermal generators over time. The Legislature enacted the California Renewable Portfolio Standard in 2002 and accelerated the targets in 2006 to require all retail sellers to achieve a 20% renewable portfolio by 2010.[710] In 2006, the Legislature also enacted the Global Warming Solutions Act which required California to reduce its Greenhouse Gas Emissions to 1990 levels by 2020 and was well understood to have

701 Ex. SCE-05v1, p.221.
702 Ex. TURN-13-E, p.60.
703 Transcript, May 7, 2024, p.487.
704 Ex. TURN-13-E, pp.60-61.
705 Ex. SCE-05v1, p.220, Table III-46.
706 Ex. TURN-13-E, p.61.
707 Ex. TURN-705, SCE response to TURN Data Request 117, Q17(e).
708 Ex. TURN-13-E, p.63.
709 Ex. TURN-13-E, p.62.
710 SB 1078 (Sher, 2002); SB 107 (Simitian, 2006)

major implications for the power sector.[711] Despite the clear evidence of increasing reliance on renewable and low carbon resources in the following years, SCE management chose not to repair or re-install the inlet flow distribution grids. This choice was at odds with the original plant design that included inlet flow distribution grids to provide greater operational flexibility.[712]

SCE's actions fail the reasonable manager test that requires the Commission to evaluate whether utilities acted reasonably based on "facts that are known or should have been known at the time."[713] The Commission should recognize that SCE did not act prudently in 2007 when it failed to repair the existing system or seek remedies from the vendor. Asking ratepayers to bear 100% of the costs to re-install these components that were previously removed at the discretion of SCE management is not reasonable. TURN's cost sharing proposal would fairly allocate some costs resulting from this avoidable mistake to SCE's shareholders.

24.2.1.4 Turbine Control and BCS Project

SCE forecasts spending $7.872 million on the Turbine Control System (TCS) and Baseline Security Center (BSC) project in 2027 and 2028.[714] The TCS entails a combination of hardware and control system applications used to manage the operational performance of the GE turbines and auxiliary equipment at Mountainview. The BSC is a set of hardware and applications that are integrated into the Turbine Control System and perform various cybersecurity functionalities to bring in enhanced security measures. SCE argues that the project

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711 AB 32 (Nunez, 2006)
712 Transcript, May 7, 2024, p.491.
713 D.90-09-088, pp.15-16.
714 Ex. SCE-05v1, p.220, Table III-46.

represents a "five-year lifecycle refresh" of the Turbine Distributed Control System Upgrade project included in this GRC and scheduled for 2023.[715]

As explained in TURN's testimony, SCE previously requested funds for this project and massively underspent relative to its forecasts. In the 2018 GRC, SCE requested $1.1 million in 2019 and $13.3 million in 2020. In the 2021 GRC, SCE requested $6.0 million in 2021.[716] SCE spent $47,000 in 2020, $240,000 in 2021, and $1.322 million in 2022.[717] In other words, SCE forecasted more than $20 million in the prior 3 GRCs for this project but spent less than $2 million. This historical pattern does not support the reasonableness of SCE's forecast in this GRC.

In rebuttal testimony, SCE argues that TURN's critiques regarding past actual spending compared to proposed spending are misplaced because prior requests for capital expenditures were forecasted to occur in attrition years.[718] Whether SCE's proposed expenditures for those projects in prior GRCs were to occur during attrition years or during the Test Years, SCE still proposed the projects and requested Commission approval for the proposed level of expenditures.

Finally, SCE does not "understand" TURN's objections to this project since it is forecast to occur during the attrition years of this proceeding.[719] This objection could apply to any capital project proposed by SCE outside of the test year. If there is no relevance to capital expenditures proposed during the attrition years, it is unclear why SCE is concerned about TURN's

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[715] Ex. TURN-13-E, p.64; Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q24.b.i (revised). The TCS project is projected to occur in 2023 at a cost of $5.913 million.
[716] Ex. TURN-13-E, p.64. These requests were not only for the Turbine Control System and BCS Project but for other work as well.
[717] Ex. TURN-13-E, p.64.
[718] Ex. SCE-16, p.63.
[719] Ex. SCE-16, p.63.

objections. Given the unreasonable magnitude of the proposed capital expenditures for this project, and the historical pattern of overforecasting and underspending, TURN believes that it deserves greater scrutiny by the Commission.

For these reasons, TURN recommends that the Commission reject SCE's forecast in this GRC. Ratepayers should not have to repeatedly bear the costs of a project for which SCE has already received funding in past GRCs. However, if the Commission is convinced that this project is reasonable, then TURN would propose establishment of a one-way balancing account with a memorandum account to track overspending to ensure that SCE actually does pursue the project.

24.2.1.5 GE Variable Load Path project

SCE originally proposed to spend $6.319 million in 2026 and 2027 on the GE Variable Load Path project.[720] The project is a control system upgrade intended to improve plant efficiency at lower power levels and improve emissions performance during periods of cyclic operation.[721] SCE argues that the project is designed to allow Mountainview to "remain competitive" with newer generation power plants with higher efficiency.[722] TURN opposed funding for this project because SCE failed to demonstrate cost-effectiveness and has not done any engineering or economic analysis of the project.[723]

In rebuttal testimony, SCE noted its decision to remove this project from the capital forecast.[724] Under cross examination, SCE witness Maddox stated that SCE is not planning to

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[720] Ex. SCE-05v1, p.220, Table III-46.
[721] Ex. TURN-13-E, p.65.
[722] Ex. SCE-05v1, p.228.
[723] Ex. TURN-13-E, pp.66-67.
[724] Ex. SCE-16, p.63.

pursue this project "at the present time."[725] TURN and SCE therefore agree that no spending related to this project should be included in the capital forecast.

24.2.2 Peakers Capital

TURN's testimony identified one capital project proposed for SCE's fleet of gas-fired peaker plants that was not adequately supported by SCE in its application. SCE proposes to change out existing microprocessor-based relays at its peaking plants with newer-generation microprocessor-based relays. This project is forecast to cost $4.0 million with expenditures of $1 million per year from 2025-2028.[726] TURN recommends reducing SCE's forecast by $1 million in 2025 and $1 million in 2026.[727] The impacts of TURN's recommendations are shown in the following table:[728]

Peakers Capital Expenditures - TURN adjustments to SCE forecast							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
SCE Total Peakers Capex	320	502	1,852	1,052	3,572	4,102	11,402
less TURN Adjustments							
Delay Changeout of Relays at Peakers Until at Least 2027			(1,000)	(1,000)			(2,000)
Subtotal Impacts of TURN Recommendations for Chapter 5			(1,000)	(1,000)			(2,000)
SCE Total Peakers Capex after Applying TURN Adjustments	320	502	852	52	3,572	4,102	9,402

SCE notes that the existing relays will reach their designed service life of 20 years in 2027 and 2028 and argues that replacements should begin before the 20-year life has elapsed regardless of whether there are any failures.[729] SCE asserts that these peakers provide needed Black Start capability for the California grid that cannot afford to be jeopardized in the event of a relay failure.[730] SCE further claims that the existing relays are not compatible with current laptop

[725] Transcript, May 7, p.492.
[726] Ex. SCE-05v1, p.247, Table III-47.
[727] Ex. TURN-13-E, p.10, Table 4.
[728] Ex. TURN-13-E, p.10, Table 4.
[729] Ex. SCE-16, pp.69-70.
[730] Ex. SCE-16, p.70.

software used by technicians and failure to test the relays every six years would violate relevant compliance requirements.[731] Finally, SCE references an "economic analysis" that shows an economic benefit of the program.[732]

TURN identified a number of flaws and gaps in SCE's claims that raise questions about the need for new capital spending on the relays, particularly during the 2025 test year. First, TURN noted that the relays are designed to operate for 20 years and replacement should not be assumed to occur prior to that date absent a showing of reliability issues with the relays.[733] Second, TURN noted that SCE's technicians were successfully able to use compliant laptops to test the existing relays in 2019, 2022 and 2023. In response to a TURN data request, SCE stated "to date, SCE has not experienced any known communication troubles with the applicable relays at the Peakers and has been able to meet all 6-year compliance testing requirements."[734] Furthermore, SCE's proposed relay replacement schedule still assumes that existing relays at two facilities will be tested in 2025 with replacements occurring 1-2 years later.[735]

TURN further reviewed SCE's "economic analysis" which includes a hard-wired assumption that there is a 90% probability the plant will trip offline due to failure of relay on the date assumed for its replacement with a 3% annual growth in that failure probability.[736] TURN's testimony notes that "SCE gives no indication how it came up with these parameters".[737] SCE's rebuttal testimony offers no additional insights or information to support the validity of their analysis. In rebuttal testimony, SCE further claimed that relays should be replaced when there is

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[731] Ex. SCE-05v1, p.248.
[732] Ex. SCE-05v1, p.249.
[733] Ex. TURN-13-E, p.69.
[734] Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q25.b.i.
[735] Ex. TURN-13-E, p.70, Table 25.
[736] Ex. TURN-13-E, p.71; Ex. TURN-705, SCE response to TURN Data Request 117, Q23.
[737] Ex. TURN-13-E, p.71.

a 63% probability of failure but SCE witness Maddox stated that this reference in SCE's rebuttal testimony "is a tad misleading" and clarified that this calculation "does not correlate to the need to replace protective relays" and does not relate to anything that could affect the reliable operation of the turbine,[738] Additionally, SCE's responses to TURN data requests indicate that repairs are possible "using available parts" as needed.[739] SCE witness Maddox explained that "there are spare parts available for some of the relays."[740]

Additionally, SCE's claims about the need for every peaker to continuously serve as a Black Start resource are overblown because they fail to consider the range of generators that provide this capability, do not identify the specific need for these resources on the CAISO system, and provide no analysis to support the claim that even a single peaker being offline for repairs would result in a violation or threaten system reliability. In response to a TURN data request, SCE provided a list of all generation capacity located south of Path 26 and north of SONGS on the CAISO grid that will provide black start capabilities by 2025. This list includes approximately 1,300 MW of Net Qualifying Capacity with Black Start capability in this geographic zone with SCE's entire peaker fleet representing approximately 18% of the total Black Start resource.[741] Each one of SCE's peaker units constitutes less than 4% of total Black

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[738] Transcript, May 7, pp.496-498. Subsequent to Mr. Maddox's appearance in hearings, SCE asked witness Billapati, who is not directly responsible for peaker operations, to provide an alternative perspective on the failure probability scores. Mr. Billapati claimed that the 63 percent replacement score is a manufacturer projection that "roughly centers around 15 years of operation of the relay" (Transcript, May 13, page 790) SCE did not explained why, if the existing relays are 63% likely to fail after 15 years of operation, they planned to delay replacements until a later date.

[739] Ex. TURN-705, SCE response to TURN Data Request 117, Q23.
[740] Transcript, May 7, p.499.
[741] Ex. TURN-704, SCE response to TURN Data Request 117, Q24.

Start capability in this area. SCE failed to demonstrate that any peaker availability would threaten system reliability or result in insufficient systemwide black start capability.

Finally, SCE was unable to provide basic information about the type, quantity and unit cost of replacement relays and could not even identify "which relays need to be replaced".[742] It is not clear how SCE was able to develop a capital expenditure forecast without this basic information.

Given these problems with SCE's justifications for the cost and timing of the project, TURN recommends delaying any forecasted capital expenditures until at least 2027 which is the end of the designated service lives for relays at Mira Loma, Grapeland, Barre and Center. This delay would result in a $1 million reduction to capital expenditures forecast for 2025 and 2026.

24.2.3 Decommissioning Accruals and Contingency

SCE proposes revised decommissioning costs for Mountainview ($14.036 million) and the Peakers ($6.02 million) based on two new studies performed for this GRC.[743] Both of the decommissioning studies use a 20% contingency. TURN recommends the use of a 15% contingency which would reduce the decommissioning estimates for Mountainview and the Peakers to $13.167 million and $6.020 million (2021$), respectively.

TURN's proposal for a 15% contingency factor recognizes the fact that decommissioning is not expected to occur for many years. By contrast, TURN recommends a 10% contingency factor for the SPVP projects scheduled for decommissioning in 2025 and 2026.

The 20% factor proposed by SCE is inconsistent with the 15% contingency factor approved by the Commission in SCE's last GRC for purposes of decommissioning costs relating

[742] Ex. TURN-704, SCE response to TURN Data Request 117, Q29.
[743] Ex. TURN-13-E, p.114.

to fuel cell projects.[744] Additionally, a 15% contingency factor is comparable to assumptions used by Pacific Gas & Electric and San Diego Gas & Electric.[745] Further, SCE uses a contingency of 10% or less for almost all of SCE's other electric generation-related capital projects.[746]

SCE's own experience demonstrates that decommissioning contingencies have rarely been used for generation projects. In response to a TURN data request, SCE identified five generating projects that have been decommissioned since 2000. In four of the five cases, the recorded costs used no contingency and were under the cost estimate.[747] Three of the projects had no contingency in their original estimates and only one these (the Mohave coal-fired generating station) went overbudget.[748] Also notable is the fact that SCE did not use any of its 15% contingency factor for the Perris SPVP facility or any of the contingency factor for the UC Santa Barbara Fuel Cell.[749]

In evaluating the reasonableness of SCE's contingency factors, the Commission should give weight to its recent decision in the California Water Company General Rate Case (A.21-07-002). In that decision, the Commission rejected the majority of contingency factors proposed by Cal Water for capital projects and instead assigned no contingency to that work. In doing so, the Commission rejected a "blanket approach" to contingency factors and further explained "it has

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[744] D.21-08-036, pp. 536-537.
[745] D.21-08-036, p. 536; Ex. TURN-13-E, p.114.
[746] Ex. TURN-13-E, p. 85; Ex. TURN-13-Atch1, SCE response to TURN Data Request 80, Q17.
[747] Ex. TURN-704, SCE response to TURN DR 117, Q20.
[748] Ex. TURN-704, SCE response to TURN DR 117, Q20. Since there was no contingency for Mohave, the fact that the costs were above the estimate only means that a 0% contingency factor would have been inadequate for that project. Mohave also involved a unique set of challenges given the nature of the facility. There is no evidence that similarly unique challenges are present for Mountainview and the Peakers.
[749] Ex. TURN-704, SCE response to TURN DR 117, Q20 (The Perris facility is name "Dexus" in the table)

long been our practice, consistent with ratemaking policy, to disallow contingencies in order to motivate utilities to remain within their forecast budgets for their capital projects".[750]

In support of its preferred 20% contingency, SCE argues against TURN's proposal by claiming that "contingencies are typically higher on decommissioning than construction because of the higher level of uncertainty."[751] The source SCE cites for this finding is a trade press article discussing coal-fired power plants that includes one sentence with the exact words appearing in SCE's testimony but provides no data or other supporting material.[752] That article also suggests that utilities should "research the contingencies approved in prior regulatory proceedings".[753] As described earlier in this section, TURN's research shows that other projects and utilities have used lower contingency factors. Finally, the article notes a series of decommissioning cost risks relating specifically to the environmental remediation of coal facilities including potential contamination associated with asbestos, mercury, lead paint, and coal ash ponds.[754] None of these risks apply to the relatively new gas-fired plants at issue in this case. SCE's reliance on this trade industry publication article to support its proposed contingency factor should therefore be given little weight.

SCE's arguments are not persuasive in light of actual decommissioning cost experience, the use of lower contingency factors for other generation projects, and the Commission's increasing concern about the use of blanket contingency factors for capital projects. The Commission should adopt TURN's 15% recommendation as a reasonable alternative for Mountainview and the Peakers.

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[750] D.24-04-042, pp. 25, 27
[751] Ex. SCE-16, p.64.
[752] Ex. TURN-704, SCE response to TURN Data Request 17, Q19, Attachment (p.3)
[753] Ex. TURN-704, SCE response to TURN Data Request 17, Q19, Attachment (p.3)
[754] Ex. TURN-704, SCE response to TURN Data Request 17, Q19, Attachment (p.2)

24.3 Fuel Cell

SCE operated two fuel cell projects that were disconnected from the grid at the end of 2022. The larger project (1.4 MW) was located at the campus of California State University, San Bernadino (CSUSB) while the smaller project (0.2 MW) was located at the campus of the University of California, Santa Barbara (UCSB).[755] The projects have a remaining book value of $0.299 million.[756]

SCE proposes to earn a full rate of return (7.44%) on the unamortized net book value of these assets over a four-year period.[757] SCE expects to earn approximately $0.05 million in return associated with the unamortized book value.[758] TURN recommends not allowing any debt or equity return on the unamortized book value because the assets are no longer operational. In particular, the CSUSB project was removed from service after 9 years and 3 months despite having a 10-year service life used for purposes of depreciation.[759]

SCE argues that a full rate of return should be granted when "the abandonment results in a net benefit to customers" and asserts that this condition has been met in this case.[760] The Commission should reject this claim and enforce the longstanding line of precedents denying utilities the ability to receive a rate of return on assets that are no longer used and useful. For a review of the relevant legal framework and Commission precedents addressing this issue, TURN refers to the analysis provided in Section 24.4 for the Solar Photovoltaic Projects.

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[755] Ex. TURN-13-E, pp.100-101.
[756] Ex. TURN-13-E, p.101; Ex. TURN-712, SCE response to TURN Data Request 103, Q13.
[757] Ex. TURN-13-E, p.101.
[758] Ex. TURN-712, SCE response to TURN Data Request 103, Q13.
[759] Ex. TURN-703, SCE response to TURN Data Request 117, Q39
[760] Ex. SCE-16, p.84.

With respect to the specific facts regarding the fuel cell projects, there are several salient points. First, SCE sought approval of the fuel cell projects in 2009 on its own initiative and made its own determination that utility ownership (rather than third party contracting) was appropriate.[761] SCE did not submit its original application in response to any official direction from the Commission relating to utility-owned fuel cells. Second, SCE did not conduct any cost-benefit analysis relating to continued operation of the CSUSB or UCSB fuel cells either at the same site or at another location.[762] There is no basis for SCE to claim that ratepayer savings were the reason for its decision to remove these units from service. Third, the CSUSB facility was not officially placed into service until 9 months after its intended commercial operation date due to problems with the units that required the fuel cell module to be repaired by the manufacturer.[763] This delay led to the unit being removed from service prior to the end of its 10-year depreciation life.

TURN believes that the facts justify the enforcement of the longstanding precedents governing the recovery of unamortized ratebase for prematurely retired facilities.

24.4 Solar

In 2022 and 2023, SCE deenergized its entire 80.6 MW portfolio of 23 rooftop solar power facilities and one ground mounted solar project developed under the Solar Photovoltaic Program (SPVP).[764] One additional SPVP project decommissioned in 2019 was the subject of disputes between TURN and SCE regarding rate recovery in the last GRC. In this case, SCE seeks to justify its decision to de-energize the remaining portfolio of assets and requests revenue

[761] D.10-04-028, pages 5-7.
[762] Ex. TURN-703, SCE response to TURN Data Request 117, Q37; Transcript, May 7, p.502.
[763] Ex. SCE-16, p.85.
[764] Ex. TURN-13-E, p.84.

requirements for recovery of unamortized project ratebase, ongoing O&M, and decommissioning costs.

SCE requests $4.347 million for O&M in 2025.[765] TURN recommends that ratepayers should only be responsible for 50% of ongoing lease payments for the de-energized facilities and proposes adjustments to the projected escalation rate for lease payments to reflect more reasonable future inflation assumptions. If the Commission does not adopt TURN's primary recommendation, it should direct SCE to track lease payments in a one-way balancing account to reflect the uncertainty of escalation, the fact that some leases have already been terminated, and the prospect that others will be terminated in the coming years. The impact of TURN's primary proposal for O&M is shown in the following table:

Solar O&M - TURN adjustments to SCE forecast ($ thousands)	
	2025
SCE Total Solar O&M	4,347
less TURN Adjustments	
Reduce Lease Payments to Annual Values with Lower Escalation	(1,224)
Disallow 50% of lease payments	(1,526)
Subtotal Impacts of TURN Recommendations	(2,750)
SCE Total Solar O&M After Applying TURN Adjustments	1,597

For capital, SCE seeks approval of its $9.723 million in recorded 2023 costs, $0.201 million forecasted for 2024 forecast and $33.526 million for the 2025 test year.[766] SCE also requests approval to recover the remaining book value of its retired projects at a full rate of return over the remaining 6.5 years of their anticipated service life.[767] TURN recommends that SCE's capital forecast be reduced to reflect a 50% disallowance and the use of a 10%

[765] Ex. SCE-16, p.92.
[766] Ex. SCE-16, p.98.
[767] Ex. TURN-13-E, p.94.

contingency for decommissioning costs.[768] TURN further proposes that ratepayers be held responsible for only 50% of unamortized ratebase associated with the retired projects and that this amount be recovered without any rate of return over the course of six years.[769] TURN further urges the Commission to require SCE to identify the amount of stranded distribution plant associated with the SPVPs and add this amount to the net book value subject to TURN's proposed solar ratemaking adjustment (50% disallowance, no rate of return). The impacts of TURN's proposals for capital and ratemaking disallowances are shown in the following tables:[770]

Solar Capital Expenditures - TURN adjustments to SCE forecast ($ thousands)							
	2023	2024	2025	2026	2027	2028	Total
SCE Total Solar Capex	11,136	201	33,526	33,109	-	-	77,972
less TURN Adjustments							
Reduce Decommissioning Costs (10% Contingency)	(475)	(9)	(1,430)	(1,412)	-	-	(3,325)
Disallow 50% of Decommissioning Costs	(5,331)	(96)	(16,048)	(15,849)	-	-	(37,324)
Subtotal Impacts of TURN Recommendations	(5,805)	(105)	(17,478)	(17,260)	-	-	(40,648)
SCE Total Solar Capex after TURN Adjustments	5,331	96	16,048	15,849	-	-	37,324

Solar Ratemaking Adjustment ($ thousands)							
	2025	2026	2027	2028	2029	2030	Total
Disallow rate of return on ratebase for retired projects	(13,750)	(11,250)	(8,750)	(6,250)	(3,751)	(1,250)	(45,001)
50% Disallowance to capital recovery	(13,870)	(13,711)	(13,567)	(13,416)	(13,263)	(13,107)	(80,934)
Subtotal Impacts of TURN Recommendations	(27,620)	(24,961)	(22,317)	(19,666)	(17,014)	(14,357)	(125,935)

TURN provides support for these recommendations in the following sections.

24.4.1 O&M costs

The primary driver of SCE's O&M forecast is lease payments for the SPVP sites hosting projects that were disconnected and will soon be decommissioned. Most lease payments are assumed to continue through 2031/2032 with one ending in 2030.[771] SCE forecasts nominal dollar lease costs for 2023 through the end of the lease period by applying an escalator based on

[768] Ex. TURN-13-E, p.13.
[769] Ex. TURN-13-E, pp.98-99.
[770] The Solar Ratemaking Adjustment table does not include any stranded distribution plant since SCE failed to attempt to identify these amounts in its testimony.
[771] Ex. TURN-707, SCE response to CalCCA Data Request 5, Q5.1.b

actual escalation in lease payments between 2020-2022 for each SPVP project and then converting the annual nominal dollar lease payments for each project to real 2022 dollars.[772] SCE sums the individual lease payments in each year to calculate the annual total lease payment (in 2022$) for 2023-2032 and then averages the total lease payments (in $2022) for the years 2025-2028 to calculate a "normalized" forecast of lease payments over this timeframe. This normalized value is presented as the 2025 forecast.[773] The average annual escalation applied to the entire portfolio of lease payments is 10.2% but the contract escalators for individual projects range from 3.35% to 15.69%.[774] Using this approach, SCE developed a "normalized" lease payment for 2025 through 2028 of $4.275 million (2022$).[775] SCE subsequently provided a revised forecast that makes certain changes to projected escalation rates for each project but SCE is not asking the Commission to use that revised forecast for purposes of establishing its O&M revenue requirement.[776]

Actual escalation for each lease is based on either the Consumer Price Index (CPI) for Los Angeles, Long Beach and Anaheim or an Annual Energy Use Charge (AEUC) that uses values from the Energy Information Administration's "Average Price of Electricity to Ultimate Customers by End-Use Sector" for the state of California.[777] Out of 25 lease sites, 19 have escalation set at the higher of AEUC or CPI and the remaining 5 are tied exclusively to CPI.[778]

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[772] Ex. TURN-13-E, p.88
[773] Ex. TURN-707, Original SCE response to CalCCA Data Request 5, Q5.1.b
[774] Ex. TURN-707, Original SCE response to CalCCA Data Request 5, Q5.1.b
[775] Ex. TURN-707, Original SCE response to CalCCA Data Request 5, Q5.1.b.
[776] Ex. TURN-13 Atch-1, SCE Revised response to TURN Data Request 80, Question 21c.
[777] Ex. SCE-16, p.96.
[778] Ex. TURN-13 Atch-1, SCE Revised response to TURN Data Request 80, Question 21c.

TURN identified a series of problems with SCE's forecasting approach that structurally bias the results to benefit shareholders. The first problem is that SCE assumes the extraordinarily high inflationary period that characterized 2021 and 2022 will continue in all future years. A review of historical AEUC data in the following table highlights the absurdity of SCE's approach:[779]

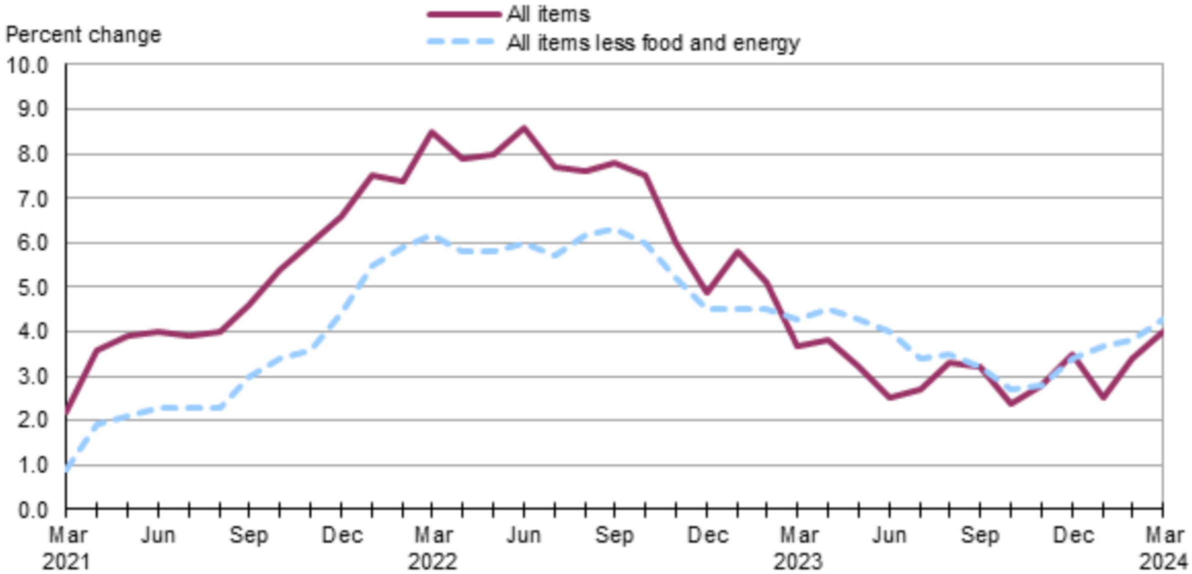
Average Price of Electricity to Ultimate Customers by End-Use Sector (US EIA) - California										
	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23
Cents/kWh	14.46	14.41	14.8	15.2	16.1	16.05	17.26	19.41	22.07	24.16
% change (vs. prior year)		-0.3%	2.7%	2.7%	5.9%	-0.3%	7.5%	12.5%	13.7%	9.5%

For leases that escalate based on AEUC, SCE's forecasting approach conveniently relies exclusively on the two annual periods with anomalously high escalation values (2020-2021 and 2021-2022) shown in this table (highlighted in yellow). When asked why SCE did not consider a longer historical time horizon for purposes of developing an escalation forecast, SCE witness Billapati simply noted that "the team" chose not to include any prior years.[780]

SCE has presented no evidence to suggest that the extraordinarily escalation occurring during that period is likely to become the norm. For lease payments that change due to the Consumer Price Index, SCE similarly relies on an extraordinarily high inflationary period (2020-2022) shown in the following chart:[781]

[779] Ex. TURN-708, US EIA Electric Power Monthly reports for "Average Price of Electricity to Ultimate Customers by End-Use Sector" (Table 5.6.A) for California.
[780] Transcript, May 13, p.817.
[781] Ex. TURN-707, US Bureau of Labor Statistics, Consumer Price Index, Los Angeles Area – March 2024.

Chart 1. Over-the-year percent change in CPI-U, Los Angeles-Long Beach-Anaheim, CA, March 2021–March 2024



Source: U.S. Bureau of Labor Statistics.

TURN's testimony provided an alternative forecast of future lease escalation values through 2032 that relies on forecasted changes in CPI (from a third party forecaster) and AEUC (from the Energy Information Administration).[782] These forecasts show escalation expected to range from 2.0% to 4.5% (nominal) over the next 10 years.[783] TURN's testimony recommends using the greater of the forecasted growth in CPI or AEUC to develop nominal dollar future lease payments that would be converted to 2022 dollars (using SCE's conversion factors) to determine annual payments for Test Year 2025. TURN's approach assumes that all SPVP project leases remain in force (and must be paid) through the GRC cycle.

SCE's rebuttal testimony takes issue with TURN's use of a national CPI forecast value (rather than one specific to Southern California) and an AEUC value for the entire Pacific Coast region.[784] However, SCE made no effort to determine whether the changes in national CPI and

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[782] Ex. TURN-13-E, pp.91-92, footnotes 114 and 115.
[783] Ex. TURN-13-E, p.92, Table 29.
[784] Ex. SCE-16, p.96.

Pacific Coast AEUC values have historically tracked with changes in the local CPI and California AEUC values included in the leases.[785] During evidentiary hearings, SCE witness Billapati acknowledged that no comparison was performed to determine whether the national and local CPI values have been historically consistent.[786] TURN acknowledges that its forecast uses CPI/AEUC values covering broader geographic areas, this approach is superior to SCE's decision to cherry-pick two of the highest inflationary years in recent history as the basis for calculating future lease payment escalation. The Commission should reject SCE's approach in favor of TURN's forecast method.

A second issue that undermines the validity of SCE's forecast is the likelihood that a significant number of SPVP leases will be terminated early and thereby reduce total payments SCE must make during the GRC cycle. This fact was omitted from SCE's prepared direct and rebuttal testimony. In response to TURN data requests, SCE acknowledged that the building owners at several SPVP sites have requested a re-roof of the facility "which provided SCE the opportunity to exercise its right to terminate the lease. Terminating those lease relieved SCE from future lease payments."[787] During evidentiary hearings, SCE witness Billapati confirmed that any such request by the building owner allows SCE to terminate the lease and avoid any future payments.[788]

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[785] Ex. SCE-16, Appendix I, pp. I3 to I4 (Changes in the CPI/AEUC in a particular year relative to a base year are used to determine lease payments)
[786] Transcript, May 13, p.821.
[787] Ex. TURN-707, SCE response to TURN Data Request 117, Q53.
[788] Transcript, May 13, p.809 ("if the building owner asks SCE to remove the panels and to reroof the entire facility, then the lease – the lease has to offer SCE the option to exercise its rights to terminate the lease. And it it's able to exercise the right to terminate, then SCE is not required to make the payments through the end of the lease.")

Despite this admission, SCE assumes that all leases will remain in force and incur payment obligations through the GRC cycle. However, three SPVP leases have already been terminated (Sites 13, 28, and 48) and will no longer require payments in 2025 and beyond.[789] Although SCE will not incur any costs relating to these leases, SCE's forecasting methodology incorrectly assumes that total lease payments to these three sites will be $0.974 million in 2025 and $4.789 million between 2025-2028.[790] These three leases comprise approximately 25% of the annual leasing costs forecasted by SCE for the entire SPVP portfolio over this time period.[791] There is no dispute that these costs will not be incurred by SCE and that any additional lease terminations would only add to the gap between forecasted and actual costs. When asked to confirm that SCE seeks to recover the entire forecast regardless of lease terminations that eliminate payment obligations, SCE witness Billapati stated "actual expenses on the leases could be lower than the original request. And that's the nature of forecasting".[792]

There is no justification for allowing SCE to collect amounts from ratepayers that will not be used to make lease payments and will instead be retained by shareholders. The beneficiaries of overforecasting are SCE's shareholders who would retain any excess revenues over this GRC period. The Commission should not allow SCE to overcollect given the information entered into the record during the course of this proceeding.

The adverse consequences for ratepayers are even more significant. As explained in the next section, TURN takes issue with SCE's cost-effectiveness analysis supporting the decision to

[789] Ex. TURN-713, SCE response to TURN-SCE-Verbal-008, Q4
[790] Ex. TURN-707, SCE response to CalCCA Data Request 5, Q5.1.b (values for 2025 for sites 13, 28 and 48)
[791] Ex. TURN-707, SCE response to CalCCA Data Request 5, Q5.1.b (values for 2025 for sites 13, 28 and 48 divided into the "total" values in 2025, 2026, 2027 and 2028)
[792] Transcript, May 13, p.815.

prematurely retire the SPVP facilities. One of the key inputs to the forecasted costs of continued operations (rather than retirement) is the assumption that, for all but one of the SPVP projects, the building owner will request a re-roofing that requires the projects to be entirely removed (and subsequently re-installed).[793] SCE assumes that all these requests will occur during the current GRC cycle (between 2024-2027).[794] Had SCE decided to continue operations at these facilities, rather than preemptively de-energizing the projects and committing to prompt decommissioning, future re-roofing requests (if they actually occur) would provide SCE with early termination rights and relief from ongoing lease payments for the remainder of the original lease term.

SCE's unilateral decision to retire and decommission these projects may foreclose the opportunity to benefit from early lease terminations since SCE would no longer have early termination rights once the systems are no longer on the building roofs. Instead, the full lease payments would be required through their original term. As a result, SCE's announcement of early retirement is likely to <u>increase</u> the total leasing costs relative to a scenario where SCE only retires an SPVP project if the building owner makes a re-roofing request (which would terminate the lease obligations). The Commission should take this "self-own" into account when assessing the reasonableness of SCE's overall actions.

Given these serious issues, TURN makes several recommendations for the O&M forecast for lease payments. First, any leases for which ratepayers are responsible should be assumed to escalate at the lower annual rates included in TURN's testimony. Second, ratepayers should only be responsible for 50% of forecasted lease payments to reflect both the fact that 25% of

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[793] Transcript, May 13, pp.799-800.
[794] Ex. TURN-707, SCE response to TURN Data Request 103, Q1, "Ongoing O&M" attachment, "Remove and Reinstall year".

forecasted lease payments are associated with leases that have already been terminated, the fact that additional leases may be terminated in the coming years due to re-roofing requests, and the fact that SCE's decision to unilaterally announce the retirement of these projects will likely result in higher lease payment obligations (relative to a scenario where SCE waited to receive a re-roofing request before deciding to decommission a facility).

If the Commission does not adopt TURN's primary recommendations, it should direct SCE to track lease payments in a one-way balancing account (the cap should be set using inflation forecast assumptions consistent with TURN's approach and remove the three terminated leases). TURN did not make this recommendation in direct testimony because the impact of reroofing requests on SCE's ability to request lease termination was only revealed in response to data requests relating to SCE's rebuttal testimony. TURN's alternative approach would ensure that SCE only recovers the actual costs of lease payments incurred through the GRC cycle. Disallowances for imprudence and unreasonable determinations could be addressed through a reduction in capital recovery discussed in the next section.

Ratepayers should not bear the costs of SCE's inflated (and demonstrably wrong) forecasting methodology or the adverse consequences of preemptively telling building owners seeking to reroof that they can continue to collect lease payments for the rest of the decade so long as they wait until SCE removes the installed solar project in the next few years. The Commission should assign ample responsibility to SCE and its shareholders for these easily-avoidable mistakes that constitute imprudence.

24.4.2 Capital costs

24.4.2.1 Reasonableness of SCE's management

24.4.2.1.1 SCE did not demonstrate prudent management of SPVP

The SPVP projects were installed between 2008 and 2013.[795] When SCE originally asked for approval to invest in these facilities, it assumed a 20-year life for all projects and noted that panel warranties "range from 20-25 years" and the racking system should be expected to have a depreciable life of 30 years.[796] SCE's original application seeking approval of the SPVP did not include any assumption that facilities may have to be prematurely removed due to re-reroofing requests or safety issues.[797] The Commission should give little weight to SCE's current claim that the projects were essentially experimental and could not have been expected to operate for more than 12-15 years.[798] This assertion is little more than a *post hoc* rationalization to justify a program that is characterized by massive stranded costs, poor performance and imprudent behavior by SCE. The SPVP program has been nothing short of a fiasco.

SCE engaged vendors and contractors to build the SPVP sites and relied on contractors to perform periodic inspections of the facilities.[799] In testimony, SCE claims that the mounting system for the SPVPs was "largely untested" but, in response to data requests from TURN, was unable to identify the extent to which this system was in commercial use at the time the projects were installed.[800] The notion that the mounting system involved new and untested technology was never referenced in SCE's original application seeking Commission approval.

[795] Ex. SCE-05v1, p.268.
[796] Ex. TURN-707, SCE testimony in A.08-03-015, pp.51-53.
[797] Ex. TURN-706, SCE response to TURN Data Request 117, Q51.
[798] Ex. SCE-16, p.108.
[799] Ex. TURN-706, SCE response to TURN Data Request 103, Q8.
[800] Ex. SCE-16, p.108; Ex. TURN-706, SCE response to TURN Data Request 117, Q48

The primary trigger for SCE's decision to evaluate the cost-effectiveness of continued operations was fire incidents at two SPVP sites (12 and 22) in 2021 caused by faulty panel connectors.[801] SCE asserts that the first time corrosion in the panel connections was noticed was after the ignition event at SPVP 012 in December 2021.[802] Upon noticing that many sites were at risk for similar fires, SCE decided to immediately de-energize the eight highest risk sites.[803]

There is ample reason to believe that SCE knew, or should have known, about the connector problems and other safety risks at SPVP facilities prior to the fire in December 2021. The Standard Cause Evaluation performed by SCE staff in 2022 noted that "hanging wires", "wires on the ground" and "bad connectors" were first identified as issues to be addressed at SPVP 12 in an inspection conducted in May of 2018.[804] Additional inspections in mid-2021 found similar problems and identified the need for urgent repairs. However, no repairs were made and the facility experienced a fire in December 2021.[805] A contributing cause identified in the report was "inadequate maintenance procedures" [806] The fact that SCE did not notice these same problems at other SPVP sites until there was a fire at SPVP 12 highlights a failure to conduct adequate regular maintenance and inspections.

Surprisingly, SCE was unable to identify the manufacturer of the defective parts or explain whether the defective parts were ordered by SCE or third-party contractors.[807] SCE also

[801] Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q29(d).
[802] Ex. TURN-706, SCE response to TURN Data Request 117, Q47.
[803] Ex. SCE-16, p.107.
[804] Ex. SCE-16, p.B16.
[805] Ex. SCE-16, p.B16.
[806] Ex. SCE-16, p.B16.
[807] Ex. TURN-13-Atch1, SCE response to TURN Data Request 80, Q27.

failed to pursue claims against any vendor or manufacturer relating to design, manufacturing, or installation deficiencies with any SPVP project.[808]

The overall actions of SCE do not support a finding of prudent management. SCE's original application never mentioned any of the risks that subsequently materialized, assumed a standard 20-year project life, and never included the extremely relevant assumption that the building hosting every facility would need to be re-roofed prior to the end of the 20-year lease.[809] SCE's delegation of procurement and installation to third parties with apparently minimal oversight or recordkeeping resulted in projects riddled with safety defects. SCE was on notice as to connector issues and bad wiring in 2018 but took no action until after a fire in December of 2021, after which SCE abruptly de-energized many facilities. The fact that SCE chose to de-energize all the remaining SPVP facilities approximately half-way through their expected operational lives based on safety concerns and questionable economic analysis does not represent reasonable performance or reflect typical industry experience. The Commission should find that SCE's management was imprudent and order disallowances of unrecovered capital as a remedy.

24.4.2.1.2 SCE's decision to prematurely retire all projects was driven by flawed analysis

SCE supports the decision to prematurely decommission its SPVP facilities in late 2022 based on an economic analysis performed in the third quarter of 2022.[810] This analysis purports to show that "decommissioning in 2025 and 2026 is the least-cost alternative to SCE customers".[811] Specifically, the analysis finds that prematurely decommissioning the projects in

[808] Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q28(c) Supplemental.
[809] Ex. TURN-706, SCE response to TURN Data Request 117, Q51.
[810] Transcript, May 13, pp.792-793.
[811] Ex. SCE-05v1, p.271.

2025 and 2026 would cost $295 million while continuing to operate them to the end of their original asset life would cost $393 million.[812] After reviewing the inputs to this analysis, only some of which were provided after repeated data requests, TURN is persuaded that structural flaws render its conclusions fundamentally incorrect. The analysis was designed to justify a choice that SCE had likely already made (prematurely decommission all SPVP facilities) and to hopefully convince the Commission not to enforce either a capital cost disallowance or deny SCE a return on sunk plant in a manner similar to the treatment for the Perris SPVP project adopted in the last GRC.

TURN's concerns fall into two basic categories. First, the valuation of SPVP project benefits is unreasonably low. The analysis finds only $19 million in cumulative energy, generation capacity and Renewable Energy Credit benefits attributable to these projects through the end of their expected operational lives.[813]

The Commission should decline to rely on this analysis. SCE refused to provide the generation profiles assumed for the SPVP projects in its cost-effectiveness analysis despite direct requests from TURN.[814] SCE relied on a "proprietary price forecasting mechanism" for future energy prices, declined to share these values with TURN, and refused to explain whether these values are consistent with the energy price forecast used for Integrated Resource Planning purposes by the Commission or the wholesale energy price forecast used for the Avoided Cost Calculator.[815] For capacity prices, SCE also relied on a September 2021 proprietary forecast that

[812] Ex. SCE-05v1, p.271, Table IV-49.
[813] Ex. SCE-05v1, p.271, Table IV-49.
[814] Ex. TURN-706, SCE response to TURN Data Request 117, Q44.
[815] Ex. TURN-706, SCE response to TURN Data Request 117, Q45(a).

it refused to provide to TURN.[816] As a result, it is impossible for TURN or the Commission to assess whether SCE's input values and calculations are reasonable.

TURN's testimony provided the results of a preliminary analysis of the value of SPVP projects using values from the 2022 Avoided Cost Calculator (ACC) which, for stand-alone solar projects, are driven by forecasted wholesale energy prices and some credit for generation capacity during peak hours. TURN's analysis found that the operation of these projects would provide \$80-100 million (nominal) in ratepayer benefits through 2032.[817] Unlike SCE's proprietary modeling, TURN's use of the ACC is transparent and relies on Commission-approved values. Given the lack of transparency with SCE's forecast methodology, and the extraordinarily low benefits attributed to the operation of these projects, the Commission should decline to find that \$19 million in benefits from ongoing operation is reasonable.

The second (and bigger) problem with the analysis is the assumed cost for "ongoing O&M" assigned to the scenario where the SPVP facilities are <u>not</u> prematurely decommissioned. "Ongoing O&M" accounts for \$164 million under the continued operations scenario but only \$12 million under the premature decommissioning scenario.[818] Given that the overall cost difference between the two scenarios is \$98 million, and the difference in Ongoing O&M between the two scenarios is \$154 million, the basis for the "ongoing O&M" calculation should be carefully examined. Out of the \$164 million calculated for "ongoing O&M", approximately \$142 million (NPV) is attributable to "remove and reinstall".[819] This category calculates the cost of removing the entire solar system from a rooftop and then reinstalling the system after re-

[816] Ex. TURN-706, SCE response to TURN Data Request 117, Q45(b).
[817] Ex. TURN-13-E, p.98.
[818] Ex. SCE-05v1, p.271, Table IV-49.
[819] Ex. TURN-707, SCE response to TURN Data Request 103, Q1(b), "Ongoing O&M" attachment.

roofing has occurred.[820] SCE provides no basis for the costs needed to perform this work at each site in its testimony or workpapers. The values for each project are simply hardcoded into the spreadsheet provided to parties seeking workpapers.[821]

According to SCE, these "remove and reinstall" costs would be incurred if the building owner needs to re-roof the building.[822] Of the 24 SPVP installations, SCE's analysis assumes that 8 are removed/reinstalled in 2024, 8 removed/reinstalled in 2025, 5 are removed/reinstalled in 2026, and 2 are removed/reinstalled in 2027.[823] Under the model logic, earlier removal/reinstall dates have a larger impact on the total NPV cost than later dates. After its own witness completed testifying, SCE provided additional written responses acknowledging that its model inaccurately included remove/re-install costs for a ground mounted installation (Site 42).[824] This mistake inflated costs under the continued operation scenario by $13 million (NPV) but is not shown in the results of SCE's analysis provided in testimony.

SCE provides no specific support for the assumption that every single building owner will seek to re-roof during this time period. SCE witness Billapati admitted that the dates selected in the analysis are "not based on a specific request from the building owner to remove the panel in order to perform the reroofing or any major refurbishment".[825] SCE did not consider an alternative where only some building owners seek to re-roof. Instead, SCE relied on a forecast based on an opaque methodology that was never disclosed or explained in testimony or data

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[820] Transcript, May 13, p.799.
[821] Ex. TURN-707, SCE response to TURN Data Request 103, Q1(b), "Ongoing O&M" attachment, "remove and reinstall (nominal)"
[822] Transcript, May 13, p.799.
[823] Ex. TURN-707, SCE response to TURN Data Request 103, Q1(b), "Ongoing O&M" attachment. 1 facility (Site 28) is assumed not to require removal/reinstallation.
[824] Ex. TURN-713, SCE response to TURN-SCE-Verbal-008, Q3
[825] Transcript, May 13, p.802.

responses. This forecast conveniently assumes that almost all building owners would initiate reroofing within a three-year period (2024-2026) at the front end of the current GRC cycle, thereby maximizing the cost impacts under the continued operation scenario. The arbitrary re-roofing assumption is intentionally constructed to support the outcome that SCE intended the exercise to produce.

Additionally, SCE does not consider a scenario where projects are refurbished and continue to operate until a building owner decides to re-roof. As explained in the discussion of O&M costs, SCE's decision to prematurely retire SPVP facilities appears to have locked in significant lease payment obligations through 2032 that could have otherwise been avoided. SCE acknowledges that the obligation to make lease payments through 2032 is unaffected by the decision to prematurely decommission projects.[826] Had SCE waited until receiving a re-roofing request to decommission a project, all future lease payments associated with that site could have been avoided.

SCE's own analysis shows that refurbishing the projects now and operating them until a reroofing request is made would be cost-effective. SCE's workpapers reveal that the incremental costs of refurbishment and new telemetry at every SPVP site (total of $15.8 million) would be more than offset by SCE's avoided lease payment obligations and the ongoing electric production benefits even if all building owners decide to reroof between 2024-2028.[827] This obvious alternative approach was not considered by SCE in its analysis.

[826] Ex. TURN-706, SCE response to TURN Data Request 117, Q52.
[827] Ex. TURN-707, SCE response to CalCCA Data Request 5, Q5.1.b (avoiding lease payments for all SPVP projects starting in 2028 would yield $25 million in savings); Ex. TURN-707, SCE response to TURN Data Request 103, Q1(b), "Ongoing O&M" attachment (total refurbish and telemetry costs for all SPVP projects assumed to be $15.8 million); Ex. TURN-707, SCE response to TURN Data Request 103, Q1(a), "Benefits" attachment (total solar benefits from 2023-2033 assumed to be $26.17 million).

SCE's approach is patently unreasonable. There is no credible basis for SCE to assume that all building owners hosting SPVP facilities would seek to re-roof prior to the end of the leases and specifically during a compressed period of a few years at the front end of this GRC cycle. SCE did not survey building owners or base this assumption on specific requests from the owners. Instead, SCE arbitrarily selected near-term dates, applied them to all but one of the SPVP projects, and then generated large cost values that could support its claim that premature retirement was cost-effective. SCE ignored potential savings from avoided lease payments if the owner decides to reroof, savings that are lost if SCE proactively removes the system, and undervalued the benefits of continued operations.

24.4.2.2 Treatment of unrecovered ratebase

24.4.2.2.1 TURN's proposal

For the unrecovered net book value of the SPVP assets that were removed from service, TURN proposes that ratepayers be held responsible for only 50% of unamortized ratebase associated with the retired projects. TURN further recommends that any allowable recovery of this sunk capital exclude any rate of return on debt or equity and be amortized over the course of six years.[828] According to SCE, all SPVP projects were disconnected from the grid in March and April of 2023. At that time, the net book value for these assets was $103.048 million.[829] TURN recommends enforcing its ratemaking treatment based on the net book value for these facilities at the time they were removed from service.

TURN's recommendation to deny a rate of return on unrecovered capital does not rely on a finding of imprudence by the Commission. In the last GRC, the Commission adopted TURN's

[828] Ex. TURN-13-E, pp.98-99.
[829] Ex. TURN-712, SCE response to TURN Data Request 117, Q64.

proposal to deny SCE any return on the unrecovered capital associated with the Perris SPVP and recover the remaining net plant over six years.[830] There was no finding of imprudence in that proceeding. Even if the Commission finds no unreasonable actions by SCE, the same treatment should be applied to all SPVP capital deemed eligible for recovery in this case.

TURN's recommended disallowance of unrecovered capital is based on both SCE's mismanagement of the SPVP projects and its decision to prematurely retire the assets in reliance on an intentionally flawed cost-effectiveness analysis. SCE's imprudent actions resulted in a large stranded cost obligation, much of which was avoidable, that should not be born exclusively by ratepayers. Although the Commission declined to enforce a capital disallowance for the Perris SPVP facility in the last GRC (D.21-08-026), TURN's recommendation in this proceeding is based on different facts.

For the Perris facility, SCE was forced to remove the project due to a reroofing request by the building owner and determined that it was uneconomic to reinstall the project. After the issuance of D.21-08-026, SCE made a unilateral decision to proactively deenergize and decommission all the remaining SPVP sites. SCE justifies this decision through a flawed economic analysis that assumes every remaining project will be subject to a hypothetical future re-roofing request (conveniently occurring in 2024-2027 timeframe covered by the next GRC). The analysis is wrong and SCE's decision to prematurely decommission the remaining facilities was an unreasonable mistake of its own making. A decision to continue operations at facilities not subject to actual re-roofing requests would have benefited ratepayers. SCE's unreasonable action also jeopardized its ability to benefit from lease terminations that would relieve ratepayers

[830] D.21-08-036, p.534.

of the obligation to make payments for the remainder of the decade. These consequences merit a remedy that protects ratepayers rather than rewarding SCE's shareholders.

Furthermore, the disclosure of safety issues and poor maintenance/inspection practices at the remaining SPVP sites did not occur until this proceeding. That issue was not available for the Commission to consider in the last GRC or in any prior proceeding where capital recovery was at issue. The issue is therefore reviewed for the first time in this GRC. TURN believes that SCE's poor maintenance and inspection practices should serve as an additional basis for the disallowance of capital.

24.4.2.2.2 Commission precedents governing recovery of ratebase that is no longer "used and useful" are clear and consistent

SCE seeks to realize a full return on the unrecovered capital investment in its entire fleet of SPVP facilities despite the fact that these projects are no longer "used and useful" and were retired up to 10 years before the end of their expected operational and depreciable lives. TURN opposes this treatment as inconsistent with long established precedents governing abandoned plant and prematurely retired generation facilities. In a wide array of litigated situations involving shutdown generating facilities, the Commission has repeatedly denied any return on capital regardless of whether utility actions are demonstrated to be prudent.

The longstanding ratemaking treatment for prematurely retired facilities was not adopted to punish the utility for imprudence, mismanagement or poor planning. In circumstances where imprudence or mismanagement is involved, the Commission may disallow direct investment rather than merely denying a return on the investment (as proposed by TURN for SPVP assets in this case). By contrast, the denial of a return on capital has been characterized by the

Commission as a fair balancing of shareholder and ratepayer interests.[831] Furthermore, the US Supreme Court has repeatedly rejected the claim that denying a regulated utility recovery of capital investments that are no longer used and useful constitutes an impermissible taking under the Constitution.[832] The Commission is therefore well within its rights, and acting consistent with decades of precedents, in adopting TURN's recommended ratemaking treatment even if it finds that SCE's management decisions were reasonable and prudent.

TURN relies on a number of precedents that have guided the Commission's determinations with respect to prematurely retired facilities. In the case of Humboldt Bay Unit 3, the Commission denied any return on unrecovered capital for a nuclear plant that operated for 13 years before being prematurely retired by PG&E. The Commission explained that

> in the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits.[833]

The Commission similarly denied any return on capital for several SDG&E-owned facilities (Encina 1, Silvergate and Station B power plants) removed from service because they were no longer needed after the commissioning of the Southwest Powerlink transmission line.[834] The Commission denied any return on capital at several retired LNG facilities in the same rate

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[831] D.85-08-046, p.22 ("in the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits")
[832] *Duquesne Light Co. et al. v. Barasch et al*. (1989) 488 U.S. 299, 302, 109 S. Ct. 609, 102 L. Ed. 2d 646, 1989 U.S. LEXIS 313, 57 U.S.Lw. 4083, 98 P.U.R.4th 253 ("a state scheme of utility regulation does not "take" property simply because it disallows recovery of capital investments that are not "used and useful in service to the public."")
[833] D.85-08-046, p.22.
[834] D.85-12-108, 1985 Cal. PUC LEXIS 1112, *57.

case.[835]

The same treatment was applied to PG&E's request for the recovery of costs for Geysers 15, a prematurely shutdown utility-owned geothermal generating facility. The Commission explained that

> we once again endorse our longstanding regulatory principle that shareholders should earn a return only on used and useful plant. We note that DRA's recommendation does provide that ratepayers pay PG&E's shareholders for the entire remaining unamortized plant balance on Geysers 15, but simply not pay a return. We believe our decision is consistent with the Legislature's directives in PU § 455.5, and is fully supported by the record before us.[836]

In SCE's 2012 General Rate Case, the Commission refused to allow any return on $90 million in unrecovered capital and decommissioning costs for the prematurely shutdown Mohave Generating Station. The Commission relied upon the Humboldt 3 precedent and concluded that "shareholders should not receive a rate of return on the undepreciated, non-operational plant or decommissioning expenses."[837]

In SCE's 2021 General Rate Case, the Commission affirmed the relevance of these precedents and applied the same treatment to the unrecovered capital associated with the prematurely retired Perris SPVP facility. In doing so, the Commission stated "we agree with TURN that it is inappropriate for SCE to continue to receive a return on the Perris investment because it has been decommissioning and is no longer used and useful."[838] The Commission found no basis for an exception since the "impetus for the non-used and useful status was utility actions rather than Commission desires or actions."[839] Moreover, the Commission concluded that

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[835] D.85-12-108, 1985 Cal. PUC LEXIS 1112, *64.
[836] D.92-12-057, 1992 Cal. PUC LEXIS 971, *83, *84
[837] D.12-11-051, pp.652-653
[838] D.21-08-036, p.531
[839] D.21-08-036, p.533

there was "no demonstration that the premature retirement results in net benefits to ratepayers."[840] This conclusion is notable because SCE claimed that premature retirement of Perris was less expensive than continued operation – this rationale did not satisfy the Commission since the same facts would be true for any uneconomic asset that is prematurely retired. A mere showing that an asset is uneconomic to continue operating does not provide a waiver from the application of the "used and useful" rule to the disallowance of any rate of return on sunk capital. In every relevant precedent addressing this issue, the retired assets were uneconomic and retirement was more economic for ratepayers yet no return was authorized.

In each of these decisions, the Commission emphatically rejected the notion that prematurely retired plant should receive any return on debt or equity. The Commission should remain mindful of the unaltered and "longstanding regulatory principle" that return on capital is only available for plant that remains in service.[841] Importantly, none of these decisions rely upon a finding that imprudence was the cause of the early retirement and none characterized the denial of a return as attempts to punish the utility for bad behavior. Instead, the Commission has explained this outcome as "a fair division of risks and benefits."[842] The Commission need not reach any conclusion with respect to prudence to deny the utilities a return on their retired plant. In the event of imprudence or negligence, the Commission has other remedies such as reductions to ratebase, disallowance of outage costs or expenses, or denying the recovery of capital additions.

To the extent that the Commission has previously allowed any return on abandoned plant

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[840] D.21-08-036, p.533
[841] D.92-12-057, 1992 Cal. PUC LEXIS 971, *83, *84
[842] D.85-08-046, p.22.

or retired facilities, there are special circumstances at issue and no prior decision has authorized the full rate of return requested by SCE in this proceeding. For example, the Commission approved a settlement relating to the San Onfore Nuclear Generating Station Unit 1 that allowed unamortized capital to earn a return set at the embedded cost of debt.[843] Since this outcome was included in a Settlement, and involved an associated commitment by SCE to permanently retire the facility, it cannot be considered precedential. The Commission has expressly declined to consider D.92-08-036 as a relevant precedent.[844]

In D.11-09-017 the Commission authorized the Golden State Water Company to recover sunk costs of a facility retired due to a settlement at the utility's cost of debt while explicitly denying any return on equity on the basis that "it is not reasonable for ratepayers to pay a return on equity as if Hill Street were still used and useful or capable of providing adequate service."[845] In that case, the resolution again occurred via settlement that is not precedential.

In the case of SCE's legacy electromechanical meter retired prematurely due to the installation of advanced Smart Meters, the Commission allowed a reduced return on equity and explained that the outcome deviated "from the general principle of excluding a rate of return on the net plant balance of assets that are no longer used and useful.[846] A similar decision issued for PG&E explains that the treatment for electromechanical meters is based on special circumstances even though, as a general matter, "The Commission has determined that plant which is not used

[843] D.92-08-036.
[844] D.05-12-040, Finding of Fact #65 ("In D.92-08-036, the Commission addressed the recovery of remaining undepreciated plant investment for Unit 1, which was shut down before the end of its license life. The Commission adopted a settlement that allowed a four-year amortization of the remaining unrecovered plant investment. It also allowed a return equal to the embedded cost of debt on the unamortized balance during the amortization period. Since this decision adopted a settlement, it did not set a precedent.")
[845] D.11-09-017, p.6; D.10-06-031.
[846] D.12-11-051, pp.649-650.

and useful should be excluded from rate base (and therefore excluded from earning a rate of return)."[847] The special circumstance in both proceedings was the Commission's directive for each utility to install Smart Meters which required the early retirement of legacy meters. There are no similar special circumstances presented by SCE in the current proceeding.

These precedents demonstrate the basic presumption that, for any prematurely retired facility, the utility may not earn any return on unrecovered capital. Even in cases involving special circumstances, the Commission has authorized less than a full rate of return. By contrast, SCE's position in this case would result in a full return for abandoned plant. Consistent with decades of relevant precedents addressing similar situations, the Commission must deny this request and enforce the longstanding prohibition on a utility earning a return on plant that is no longer "used and useful".

24.4.2.2.3 There is no relevant difference between the treatment of Perris in D.21-08-036 and the situation presented in this proceeding

In the last GRC, TURN successfully argued that SCE should not earn any return on the unrecovered investments in the Perris SPVP facility at the time it was prematurely retired. The Commission stated that "we do not find it consistent with Commission precedent or a fair division of risks and benefits for ratepayers to also pay for the return on the undepreciated plant balance" and noted that "such ratemaking treatment is consistent with past treatment the Commission has adopted for similar circumstances."[848] SCE now urges the Commission to ignore that outcome and adopt the opposite treatment with respect to the remaining SPVP

[847] D.11-05-018, p.55.
[848] D.21-08-036, p.534.

facilities, arguing that the current situation is entirely different and justifies an exception from the rule. There is no basis for reaching the opposite conclusion in this case given the clear and consistent precedents governing the recovery of capital that is no longer used and useful. The Commission should reject SCE's self-serving arguments and apply the same treatment to the remaining SPVP facilities that was adopted in D.21-08-036. TURN addresses each of SCE's arguments in turn.

First, SCE claims that the retirement of the SPVP portfolio was caused by events beyond its control including defective components and lower value of solar energy in wholesale markets.[849] The fact that SCE procured defective materials, and failed to identify these defects until over a decade after the program began, should not justify rewarding the shareholders with profits for stranded capital. With respect to the lower market value of solar energy, TURN disputes SCE's valuation methodology and notes that SCE refused to provide its own energy and capacity values to TURN citing a proprietary approach. Regardless, there is no exception to the "used and useful" rule that applies when an asset is no longer economic in the marketplace. Indeed, the "used and useful" rule is typically applied because generation plant becomes stranded due to changes in market forces.

Second, SCE claims that the SPVP program involved new technologies and risks "understood by the Commission when it approved SCE's SPVP program" and that denying a return on stranded capital would "discourage future investment".[850] SCE cites no evidence that these risks were identified or discussed in the original Commission decision approving the SPVP, or that the Commission indicated a desire to provide additional ratemaking protections to

[849] Ex. SCE-16, pp.102-103.
[850] Ex. SCE-16, p.103

SCE in exchange for ratebasing new solar projects.[851] Furthermore, this same justification would apply to the Perris SPVP project addressed in the last GRC. All the SPVP projects were authorized by the same Commission decision. The Commission did not make an exception in that case and should not make a new exception in this case.

Third, SCE claims that the decision to prematurely retire the Perris facility is "completely different" because it was "based on the landlord's request to reroof the facility (which would have resulted in excessive cost if SCE elected to remove and reinstall the components to continue operations)".[852] As TURN explained in a prior section of this brief, SCE's primary justification for prematurely retiring the remaining SPVP facilities is its analysis showing that continued operations would be uneconomic. That analysis assumes that almost all of the remaining SPVP facilities will need to be removed and reinstalled due to future landlord reroofing requests. Eliminating that assumption would result in the analysis showing net benefits for continued operations (rather than benefits for premature retirement). The fact that SCE relies on the same cost driver (re-roofing requests) in this case highlights the comparability of the two cases.

Taken together, SCE's arguments fall entirely flat. There is no material difference between the circumstances surrounding the premature retirement of Perris and the remaining SPVP facilities. Any differences are irrelevant because the longstanding ratemaking approach described in the prior section is applicable in a wide range of situations with only a small number of exceptions resulting from specific circumstances not present in this case.

[851] D.09-06-049.
[852] Ex. SCE-16, p.104. The Commission addressed this issue in D.21-08-036, p.529.

24.4.2.2.4 Treatment of Distribution plant

SCE's original testimony supporting approval of the SPVP identified incremental investments in distribution plant as part of the cost of each installed project. SCE noted that distribution plant installed in connection with an SPVP facility "is the equipment needed to connect the solar PV generation to the distribution grid. The plant may include overhead conductor, underground conduit conductor, disconnect switches, distribution line transformers, services and other distribution equipment."[853] SCE assumed that this plant has an average service life of 30-55 years.[854] However, SCE's calculation of the sunk costs of SPVP facilities in this GRC excludes any distribution plant dedicated to the projects.[855] SCE acknowledges that distribution plant may be retired when the SPVP projects are removed from service but insists that these unrecovered costs should continue to be collected in ratebase.[856] TURN disagrees.

These costs are clearly attributable to the SPVP installation (as demonstrated by SCE's 2008 testimony), some of the plant is being removed as part of decommissioning, and other portions of the plant will remain unused. Allowing SCE to earn a full rate of return on this prematurely retired plant is unreasonable. The Commission can address this issue by requiring SCE to provide a full accounting of stranded distribution plant installed in connection with SPVP projects, disallowing 50% of the unrecovered book value, and declining to authorize any ongoing rate of return on that investment. Alternatively, the Commission could factoring this concern into the overall disallowance of SPVP capital proposed by TURN.

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[853] Ex. TURN-707, SCE testimony in A.08-03-015, p.53.
[854] Ex. TURN-707, SCE testimony in A.08-03-015, p.53.
[855] Ex. TURN-713, SCE response to TURN-SCE-Verbal-008, Q2
[856] Ex. TURN-713, SCE response to TURN-SCE-Verbal-008, Q2

24.4.2.3 Decommissioning costs

SCE estimates decommissioning costs of $77.697 for its portfolio of SPVPs and forecasts decommissioning will occur in 2025 and 2026.[857] This estimate includes a 15% contingency factor applied to a set of standard assumptions that use both unit costing methods and site specific factors. The unit costs are derived from both the Perris decommissioning and specific quotes received from contractors. TURN recommends a 10% contingency factor be applied to the decommissioning cost estimates. This recommendation would reduce the total estimate from $77.967 million to $74.643 million.[858]

TURN's recommendation is based on several considerations. First, the near-term dates for decommissioning (2025-2026) limit the potential for unexpected long-term developments to increase overall costs.[859] Second, SCE uses a contingency of 10% or less for almost all of SCE's other electric generation-related capital projects.[860] SCE has not provided a specific rationale for deviating from this practice with respect to SPVP projects. Third, SCE's own experience demonstrates that decommissioning contingencies have rarely been used for generation projects. In response to a TURN data request, SCE identified five generating projects that have been decommissioned since 2000. In four of the five cases, the recorded costs used no contingency and were under the cost estimate.[861] Three of the projects had no contingency in their original estimates and only one these (the Mohave coal-fired generating station) went overbudget.[862] Also

[857] Ex. TURN-13-E, p.84, *citing* Ex. SCE-05v1, p.271-272.
[858] Ex. TURN-13-E, p.86.
[859] Ex. TURN-13-E, p.85.
[860] Ex. TURN-13-E, p.85; Ex. TURN-13-Atch1, SCE response to TURN Data Request 80, Q17.
[861] Ex. TURN-704, SCE response to TURN DR 117, Q20.
[862] Ex. TURN-704, SCE response to TURN DR 117, Q20.

notable is the fact that SCE did not use any of its 15% contingency factor for the Perris SPVP facility or any of the 35% contingency factor for the UC Santa Barbara Fuel Cell.[863]

In evaluating the reasonableness of SCE's contingency factors, the Commission should give weight to its recent decision in the California Water Company General Rate Case (A.21-07-002). In that decision, the Commission rejected the majority of contingency factors proposed by Cal Water for capital projects and instead assigned no contingency to that work. In doing so, the Commission rejected a "blanket approach" to contingency factors and further explained "it has long been our practice, consistent with ratemaking policy, to disallow contingencies in order to motivate utilities to remain within their forecast budgets for their capital projects".[864]

In defense of its 15% contingency factor, SCE argues that the use of cost data from the Perris decommissioning in 2019 for purposes of the remaining SPVP cost estimates should be assumed to be too low due to post-COVID inflation.[865] However, SCE witness Billapati noted that some of the cost data was newly developed and did not rely on Perris costs.[866] Specifically, Mr. Billapati explained that the cost of panel removal "was based on the recent quote from a vendor to perform the removal work."[867] A review of the decommissioning cost estimates for two SPVP sites shows that panel removal costs comprise between 40-50% of the total cost estimate.[868] This use of recent vendor quotes undermines SCE's claim that the Perris data is unreliable and requires a contingency.

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[863] Ex. TURN-704, SCE response to TURN DR 117, Q20 (The Perris facility is name "Dexus" in the table)
[864] D.24-04-042, pp. 25, 27
[865] Ex. SCE-16, p.102.
[866] Transcript, May 13, pp.828-829.
[867] Transcript, May 13, p.829.
[868] Ex. TURN-707, SCE response to TURN Data Request 117, Q43, Attachments showing decommissioning cost estimates for 1464 Merrill Avenue and 9415 Kaiser Way.

SCE further claims that a higher contingency is appropriate because "SCE may also face claims from landlords relating to the removal work."[869] However, SCE witness Billapati stated that "SCE has not faced any claims associated with the removal scope of work".[870] The Commission should not allow for higher contingency factors based on pure speculation about theoretical liability risks that have not, in practice, ever occurred. To the extent that there are any liability issues that arise, the Commission should also evaluate whether SCE contributed to those costs through imprudent or otherwise unreasonable actions.

SCE's arguments are not persuasive in light of actual decommissioning cost experience, the use of 10% contingency factors for other generation projects, and the Commission's increasing concern about the use of blanket contingency factors for capital projects. The Commission should adopt TURN's recommendation as a reasonable alternative.

24.5 Catalina

SCE proposes several capital projects at the Pebbly Beach Generating Station (PBGS) on Catalina Island that are of concern to TURN. These projects include $2.358 million solar carports and a $1 million battery control system replacement/upgrade project.[871] Additionally, SCE initially proposed a $0.5 million capital project relating to repurposing the microturbine space at PGBS. In response to discovery by TURN, SCE indicated that it would withdraw that project from this GRC.[872] This expenditure should be removed from the capital forecast.

[869] Ex. SCE-16, p.101.
[870] Transcript, May 13, p.830.
[871] Ex. SCE-05v1, pp.258, 261.
[872] Ex. TURN-13-E, pages 81-82, *citing* Ex. TURN-13-Atch1, SCE response to TURN Data Request 28, Q23(e).

TURN opposes SCE's request to ratebase the solar carport project due to SCE's violations of the express terms of the settlement agreement adopted in D.22-11-007 by failing to consider third-party ownership. The remedy for this violation should be a removal of the project costs from the capital forecast, a prohibition on placing these costs into ratebase and a requirement that project costs be borne by SCE's shareholders. If the Commission does not agree to TURN's primary recommendation, the project should not be allowed to earn any return on invested capital. Additionally, the project timeline should be moved to reflect a likely online date of January 2026.

TURN also opposes authorizing any expenditures on the Battery Control System (BCS) project in this GRC given the uncertain lifespan for the existing battery and SCE's failure to provide any assurances that the BCS would be compatible with a future battery system. If the Commission does not agree to TURN's primary recommendation, it should clarify that removal of the BCS from service after a short period of time would render it a stranded asset ineligible for a return on unamortized capital investment.

The following table provides a summary of TURN's recommendations:

Catalina capital expenditures - TURN adjustments to SCE forecast							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
SCE Total Catalina Capex	1,998	1,079	1,000	1,000	500	500	6,077
less TURN Adjustments							
Disallow Solar Carport Costs Due to Violation of Settlement	(1,279)	(1,079)	-	-	-	-	(2,358)
Disallow BCS for NaS Battery	-	-	-	(1,000)	-	-	(1,000)
Remove Repurpose MicroTurbine Space	-	-	-	-	(500)	-	(500)
Subtotal Impacts of TURN Recommendations	(1,279)	(1,079)	-	(1,000)	(500)	-	(3,858)
SCE Total Catalina Capex after TURN Adjustments	719	(0)	1,000	-	-	500	2,219

Support for TURN's recommendations is provided in the following sections.

24.5.1 Solar Carport project

SCE proposes to install two solar carports at PBGS pursuant that would be used to charge electric vehicles and offset onsite electrical loads at the main building.[873] The project is being developed pursuant to an abatement order issued by the South Coast Air Quality Management District (SCAQMD) in September 2022 relating to a violation of particulate matter emissions at PBGS Unit 15. SCAQMD initially directed SCE to investigate the feasibility of installing a 100-400 kW solar system at PBGS and then subsequently directed SCE to install the generation by January 31, 2026.[874] The estimated cost of the two solar carports is $2.358 million.[875]

24.5.1.1 SCE's violation of the Catalina Settlement Agreement merits a remedy in this proceeding

In the last GRC, SCE sought authorization to pursue the Catalina Repower project that would have involved the replacement of six existing diesel generators at PBGS with new diesel generators.[876] TURN opposed that request based on uncertainty surrounding the timing and scope of the overall project and SCE's unreasonable commitment to continue near-total reliance on diesel to generate power for Catalina island. The Commission found that additional scrutiny of the proposal was appropriate and directed SCE to file a stand-alone application for evaluation of an updated proposal.[877]

TURN participated actively in the proceeding dedicated to SCE's stand-alone Catalina Repower Project (A.21-10-005) and engaged with SCE and Cal Advocates to reach a settlement

[873] Ex. SCE-05v1, p.258.
[874] Ex. SCE-05v1, p.258.
[875] Ex. SCE-05v1, p.258.
[876] D.21-08-036, p.360.
[877] D.21-08-036, p.362.

of contested issues that was adopted in D.22-11-007. The settlement provided a comprehensive framework governing the development of additional resources both at PBGS and at other locations on Catalina Island. Under the settlement, SCE committed to take specific actions relating to any new resources developed at the PBGS facility and elsewhere on Catalina. Section 6.2 of the settlement, which addresses the "resolution of Unit 15 Particulate Matter Noncompliance," requires SCE to consider third-party ownership for any non-diesel generation that SCAQMD requires be developed at the PBGS site. The language reads as follows:

> If the SCAQMD requires SCE to install non-diesel generation at Pebbly Beach Generation Station (PBGS), SCE will be required to consider ownership of that generation by a third party. SCE will be required to demonstrate that its proposed solution (whether owned by SCE or a third party) is appropriate based on the following factors: cost-effectiveness, reliability, safety, physical security, cybersecurity, and operational viability.[878]

This section of the Settlement specifically applies to any direction provided by SCAQMD pursuant to the Unit 15 abatement order including replacement, retrofit or retirement of Unit 15 along with "other compliance options".[879] SCAQMD has required SCE to install a solar carport (i.e., "non-diesel generation") at PBGS as part of compliance with its abatement order. Therefore, this provision of the settlement explicitly applies to the project. Under the plain language of this settlement provision, SCE is obligated to consider third-party ownership of the solar carport and is required to demonstrate that the proposed solution is cost-effective.

Despite the settlement, SCE has not taken any steps to consider third-party ownership of the solar carports.[880] SCE agrees that the abatement order does not require the solar carport to be

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[878] Ex. TURN-13-Atch1, SCE, TURN, Cal Advocates Settlement Agreement, A.21-10-005, Section 6.2 (Phase 1B: Resolution of Unit 15 Particulate Matter Noncompliance)
[879] Ex. TURN-13-Atch1, SCE, TURN, Cal Advocates Settlement Agreement, A.21-10-005, Section 6.2 (Phase 1B: Resolution of Unit 15 Particulate Matter Noncompliance)
[880] Transcript, May 7, page 530.

utility owned and acknowledged that "SCE and SCAQMD did not discuss ownership of the required onsite solar at PBGS."[881] Instead, SCE claims that the third-party ownership provision of Section 6.2 of the Settlement does not apply to the solar carport project and would only be relevant if SCAQMD were to order SCE to install non-diesel generation at PBGS as an alternative to Unit 15.[882]

SCE's description of the Settlement provision is incorrect and adds new conditions that are not to be found in the plain language of Section 6.2. The specific language in Section 6.2 applies to any non-diesel projects installed at the PBGS site pursuant to an abatement order issued by SCAQMD. This provision was negotiated by TURN based on the understanding at that time that SCAQMD might require some onsite solar generation (as had been previously proposed) in addition to any diesel replacement or refurbishment of Unit 15.[883] There is nothing in the settlement indicating that this provision applies only if SCAQMD requires the retirement of Unit 15 and replacement by non-diesel generation at the PBGS site. There is no evidence of sufficient land available at the cramped PBGS site to support a full replacement of Unit 15 with renewable generation. SCE's argument that the provision would only apply to SCAQMD-ordered renewable generation located at PBGS that completely replaces Unit 15 is neither reasonable nor plausible.

SCE further claims that the third-party ownership provisions in Section 6.2 "were clearly intended to apply to major projects like those anticipated from the Catalina Clean Energy RFO not to a tiny non-dispatchable project within the PBGS fence line."[884] This claim is similarly

[881] Ex. TURN-702, SCE response to TURN Data Request 117, Q35; Transcript, May 7, page 534.
[882] Transcript, May 7, page 530.
[883] Ex. TURN-13-E, page 78.
[884] Ex. SCE-16, p.77.

unfounded. Section 6.2 applies to Phase 1B which involves the resolution of Unit 15 Noncompliance at the PBGS site and the installation of non-diesel resources within the fence line of PBGS pursuant to an abatement order. The Settlement includes entirely different provisions for Phase 2 which relate to the evaluation of third-party ownership of projects procured under the Clean Energy RFO.[885] SCE's attempts to connect the requirements of Section 6.2 to the Clean Energy RFO constitutes a brazen misreading of the Settlement that is illogical on its face.

SCE further argues that, since parties to the settlement were aware that the January 2022 abatement order directed SCE to investigate the potential to install solar generation at PBGS, and there was no express reference to the solar carports in the Settlement, Section 6.2 was only intended to apply to a future abatement order issued by SCAQMD.[886] This argument should be rejected. At the time the parties submitted the Settlement (April 29, 2022), the latest SCAQMD abatement order (issued January 4, 2022) directed SCE to investigate the potential to add new solar generation at PBGS.[887] The settling parties (including TURN) were aware of the abatement order during the course of settlement negotiations. Since SCAQMD had not yet directed SCE to install any renewable generation at PBGS, the Settlement was crafted to ensure that any future abatement order requiring renewable generation at PGBS would be subject to an evaluation of third-party ownership. The evidentiary record of A.21-10-005 was submitted to the Commission on August 22, 2022.[888] The second abatement order requiring the installation of solar generation at PBGS was issued on September 10, 2022.[889] SCE's claim that the settlement provision should

[885] Ex. TURN-13-Atch1, SCE, TURN, Cal Advocates Settlement Agreement, A.21-10-005, Section 6.3.1 (Phase 2: All-Source Request for Offers)
[886] Ex. SCE-16, p.78.
[887] D.22-11-007, p.4; Ex. SCE-16, p.78.
[888] D.22-11-007, p.5
[889] Ex. SCE-16, p.78.

only apply to abatement orders issued after the Commission's final decision in the proceeding (November 4, 2022) is not persuasive. SCE's narrative assumes that the parties knew, at the time when the settlement was submitted (April 29, 2022), that the Commission would not issue a final decision until November and intentionally created a gap in the Settlement obligations that would not apply to any SCAQMD abatement order issued prior to a final Commission decision. There is nothing in the Settlement or the Commission decision approving the Settlement that references a "future" abatement order or creates the loophole desired by SCE.

Finally, SCE argues that the Solar Carport project is not covered by Section 6.2 because it is "not dispatchable, only serves the EV load at PBGS and SCE's PBGS building, and is in no way an alternative to diesel generation."[890] Once again, SCE inserts new limitations into the Settlement that do not appear in the actual agreement and are illogical on their face. Section 6.2 does not suggest that the requirements for the evaluation of third-party ownership only apply to "dispatchable" generation – this word and concept do not appear anywhere in the Settlement. Such a limitation would create a major loophole since most renewable generation, including solar, does not typically function as a "dispatchable" reesource. The fact that the solar carports would only serve EV charging and onsite building loads is equally irrelevant. Section 6.2 does not apply its requirements exclusively to renewable generation at PBGS that exports power to the rest of the island. Furthermore, since all loads on Catalina island are served exclusively by diesel generation at PBGS, any load at PBGS served by solar would reduce amount of load needed to be served by the diesel units at PBGS. In other words, any new solar generation on Catalina

[890] Ex. SCE-16, p.80.

island (regardless of whether it exports to the larger grid) results in a reduction in diesel generation at PBGS.

SCE's intentional violation of the Settlement is egregious, flagrant and unacceptable. TURN entered into the Settlement with the assumption that SCE would act in good faith with repect to the binding provisions. The Commission should not allow SCE to ignore or evade the terms of the adopted all-party settlement. Since the Catalina proceeding is closed, and SCE seeks to ratebase assets covered by the Settlement in the GRC, this proceeding represents the only open and logical docket where SCE's compliance can be enforced.

TURN's primary recommendation is to exclude the carport project from ratebase with the costs borne entirely by SCE shareholders.[891] This outcome would ensure that SCE faces consequences for its violation and provide proper incentives for future compliance. If the Commission does not adopt TURN's primary recommendation, SCE could be permitted to move forward with the carport project but subject to a disallowance of any rate of return on the invested capital.[892] Given that SCE would still retain some of the tax benefits that are subject to the normalization of the federal Investment Tax Credit, this outcome would still permit SCE to realize financial benefits for its shareholders.[893]

If the Commission does not wish to enforce any financial penalty for SCE's violation of the settlement, it could instead order SCE to conduct an RFO for third-party offers to build and own the solar carport and sell the output to SCE under a Power Purchase Agreement. That approach would reflect the intent of the Settlement and ensure the lowest possible costs for

[891] Ex. TURN-13-E, p.79.
[892] Ex. TURN-13-E, p.72
[893] Ex. TURN-13-E, p.79.

ratepayers. However, the absence of any financial consequences for SCE could fail to deter future noncompliance with other provisions of the Settlement.

24.5.1.2 Third-party ownership of the solar carports would reduce ratepayer costs

TURN's concern over SCE's faithful implementation of the Settlement with respect to third-party ownership is driven by the fact that utility-owned solar generation is lucrative for SCE's shareholders and generally harmful to the interests of ratepayers. In evaluating TURN's concerns, the Commission should be mindful of the disastrous experience with SCE's Solar Photovoltaic Program (SPVP) involving utility-owned solar projects that suffered safety problems, were prematurely retired, and resulted in significant stranded costs that may become the responsibility of ratepayers. TURN discusses the SPVP fiasco in Section 24.4 of this brief. With respect to the solar carport project, SCE's witness was unable to identify the expected life of the project or the duration of any warranties that would apply to procured equipment.[894] SCE's witness was similarly unable to predict whether long-term ownership of the carport project would require future refurbishment or replacement costs to be collected from ratepayers.[895]

By comparison with a utility-owned solar project, third-party ownership locks in long-term fixed pricing, places the risk of poor performance on the project owner, and prevents ratepayers from serving as the financial backstop if a project fails to operate properly, does not have sufficient warranties for defective equipment, or is prematurely retired. These benefits are relevant to assessing which ownership model favors ratepayer interests.

[894] Transcript, May 7, pp.538-539.
[895] Transcript, May 7, p.539.

TURN's testimony outlines another set of important economic benefits to ratepayers from third-party ownership of solar resources.[896] Any solar generating resource is eligible for the federal Investment Tax Credit (ITC). Federal law requires that utilities normalize the ITC while third-party project owners are not subject to this constraint and can flow through the full value in the form of price reductions in a Power Purchase Agreement.[897] This differential treatment makes utility-owned solar projects significantly more expensive for ratepayers than third-party ownership. TURN's testimony and opening brief in A.21-10-005 explains the issue as follows:

> TURN witness Dowdell explained that both bonus depreciation and the Investment Tax Credit are normalized for utility-owned assets (as opposed to being flowed through) which lowers their value to ratepayers. Additionally, SCE's net operating losses and tax credit carryovers have already zeroed out the utility's tax liabilities in the coming years, making it very difficult for these tax incentives to yield meaningful value for either the utility or its ratepayers. Finally, third party projects are typically financed with more lower-cost debt and less high-cost equity, making the overall weighted average cost of capital lower than for comparable utility-owned projects.[898]

Under normalization, the ITC value is not flowed through as generated but applied evenly *pro rata* across the useful life of the project. However, for book accounting purposes, utilities recognize ITC and accelerated depreciation as generated, thereby increasing the near-term cash available for shareholders. The value of the ITC is effectively shared between ratepayers and utility shareholders, providing an effective boost to profits at the expense of ratepayers. In A.21-10-005, TURN provided a comparative cost analysis of the same solar project owned by an IOU and a third party that accounted for both the ITC value along with different capital structure and

[896] Ex. TURN-13-E, pp. 76-78.
[897] Ex. TURN-13-E, p.77
[898] Ex. TURN-13-E, p.77, *citing* TURN opening brief, A.21-10-005, July 15, 2022, pp.10-11.

financing assumptions for each owner. This analysis found that the levelized cost (on a $/kWh basis) could be reduced by approximately 50% under third-party ownership.[899]

The significant savings available under third-party ownership was a key issue raised by TURN in A.21-10-005 and served as the basis for the inclusion of the relevant provision in the Settlement agreement relating to any non-diesel generation installed at PBGS. SCE's testimony in the GRC entirely ignores the differential benefits of the ITC to ratepayers under various ownership scenarios despite TURN identifying and explaining this issue in direct testimony.

SCE's refusal to consider third-party ownership will deprive ratepayers of lower-cost alternatives and place ratepayers on the hook for cost overruns, performance problems and premature retirement. While SCE is not motivated to seek third-party ownership, the Commission should recognize the legitimacy of TURN's concerns.

24.5.1.3 SCE's schedule for the Solar Carport Project is implausible

SCE's original testimony forecasted all capital spending on the solar carports to occur in 2023 and 2024.[900] In response to TURN's direct testimony criticizing the unrealistic timing of forecasted capital expenditures, SCE admitted that the original forecast "is inconsistent with the current status of the project" and modified its forecast by moving spending to 2024 and 2025.[901] Based on a review of likely constraints on the development of this project, TURN does not believe that it is likely the project will be completed until early 2026. The Commission should therefore adopt the assumption that the costs of this project, if allowed to be recovered from ratepayers, will not result in completed capital additions in the test year.

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[899] Ex. TURN-13-E, p.77, *citing* Testimony of Jennifer Dowdell, A.21-10-005, page 10, Table 2.
[900] Ex. SCE-05v1, p.257.
[901] Ex. SCE-16, p.80.

TURN's testimony notes that the project is currently in the "conceptual design phase," that is expected to be completed in the second quarter of 2024.[902] During hearings, SCE witness Hernandez stated that this work was ongoing was expected to be complete "by the end of June of this year."[903] Once conceptual design is complete, SCE envisions a six month design engineering phase.[904] During this phase, SCE intends to apply for all relevant permits to be issued by the City of Avalon and the California Coastal Commision.[905] SCE was unable to identify which permits may be needed or the timing involved in obtaining necessary approvals.[906] As noted in TURN's testimony, SCE intends to order equipment during the design engineering phase occurring in the second half of 2024 and assumes 12 month leadtime for procuring the necessary equipment.[907] SCE also assumes that construction will take 6 months.[908]

TURN's testimony uses these timing requirements to forecast the likely schedule for project completion.[909] TURN's forecast assumed the completion of conceptual design in the first quarter of 2024 while SCE now admits that this task will not be complete until the end of the second quarter. TURN's forecast, which includes no time delays associated with the acquisition of relevant permits (an extremely optimistic assumption), shows construction being complete in early 2026.[910] The SCAQMD deadline for completion of this project is January 31, 2026.[911] SCE's rebuttal testimony does not either respond to TURN's timeline or present any evidence to

[902] Ex. TURN-13-E, p.74.
[903] Transcript, May 7, p.535.
[904] Ex. TURN-13-E, p.74; Transcript, May 7, p.535.
[905] Ex. TURN-13-E, p.74; Transcript, May 7, p.536.
[906] Ex. TURN-702, SCE response to TURN Data Request 98, Q20; Transcript, May 7, p.536.
[907] Ex. TURN-13-E, p.74; Ex.WPSCE05V1, p. 231.
[908] Ex. TURN-13-E, p.74
[909] Ex. TURN-13-E, p.74
[910] Ex. TURN-13-E, p.74, Table 26.
[911] Ex. TURN-13-E, p.75

support an earlier online date. Given the realities of project development, and the delays that have already occurred, the Commission should direct SCE to assume, for purposes of determining when any allowable costs would be recorded to ratebase, that the project will be online in January 2026.

24.5.2 Battery Control System Upgrade

SCE requests approval of its forecast to spent $1 million in 2026 to replace the Battery Control System (BCS) on the Sodium Sulfide (NaS) battery located at PBGS.[912] The replacement is justified by the fact that the existing switchgear electronics have been experiencing performance issues.[913] At the time SCE filed its application in early 2023, the NaS battery was assumed to have five years of remaining useful life, meaning that the battery may need to be replaced in 2028.[914]

TURN opposes SCE's request as premature given the uncertainty as to whether the NaS battery will operate beyond 2028. In response to TURN data requests, SCE could not state whether the new BCS to be procured in 2026 would be compatible with a new battery that may be needed to replace the NaS unit as early as 2028.[915] If the BCS is not compatible, ratepayers would be forced to pay for a new control system that operates for only two years and then becomes a stranded asset. This outcome is unreasonable, inefficient and unfair to ratepayer interests.

There are significant unresolved questions as to whether a new BCS is actually needed at PBGS. While SCE claimed in rebuttal testimony that the existing system "has reached the end of

[912] Ex. SCE-05v1, p.257.
[913] Ex. SCE-05v1, p.261.
[914] Ex. TURN-13-E, p.80.
[915] Ex. TURN-13-E, p.80; Ex. TURN-13-Atch1, SCE response to TURN Data Request 52, Q21(c).

life and requires replacement"[916], SCE witness Hernandez clarified during hearings that "we still believe there is some remaining useful life of the BCS system as a whole".[917] Mr. Hernandez further explained that SCE recently procured parts to repair the BCS in order to conduct a complete diagnostic test and determine the likely remaining life of the entire NaS battery.[918] Based on this testimony, it is difficult to assess whether a new BCS is actually needed in the current GRC cycle, how long the NaS battery may continue to operate, and what alternatives may be under consideration in the coming years.

In rebuttal testimony, SCE argues that the failure of the battery could result in a violation of the SCAQMD Title V permit.[919] A violation would only occur if the battery is not functioning and less than 50% of the onsite microturbines are simultaneously operable.[920] Assuming SCE reasonably maintains the microturbines, delays in resolving the long-term future of the NaS battery will not result in a permit violation.

Given these uncertainties, the Commission should reject SCE's request to authorize $1 million for a new BCS and instead direct SCE present a comprehensive plan regarding the NaS battery system in the next GRC.[921] If SCE needs to replace the BCS or the entire NaS battery system prior to the next Test Year, SCE should request establishment of a memorandum account for the NaS system replacement, which would allow SCE the opportunity to have the reasonableness of its actions approved in the next GRC.

[916] Ex. SCE-16, p.81.
[917] Transcript, May 7, p.543.
[918] Transcript, May 7, p.544.
[919] Ex. SCE-16, p.82.
[920] Ex. TURN-702, SCE response to TURN Data Request 117, Q32(a).
[921] Ex. TURN-13-E, p.81.

If the Commission decides to approve SCE's proposal in this GRC, it should clarify that the removal of the BCS from service only a few years into its operational life would result in the BCS no longer being used and useful and subject to the standard ratemaking treatment for such assets (no return on ratebase, recovery amortized over 4-6 years). Contrary to SCE's claim that such treatment would be "punitive" to SCE[922], adopting TURN's recommendation would properly motivate SCE to pursue long-term solutions that benefit ratepayers rather than prioritizing short-term capital expenditures designed solely to build ratebase and benefit shareholders. Even under TURN's recommendation, SCE would still be allowed to recover stranded capital and would only be denied a return on that investment.

24.6 Nuclear / Palo Verde Nuclear Generating Station

SCE proposes to collect $83.104 for O&M costs in 2025 relating to the Palo Verde Generating Station (PVGS). Based on a review of SCE's testimony and discovery responses, TURN recommends two adjustments to the 2025 forecast. First, TURN proposes to reduce non-labor O&M by 6% to correct for sustained historic overforecasting of PVGS O&M costs. TURN also recommends that PVGS costs be tracked in a balancing account with overspending limited to 110% of the forecast value to ensure that only recorded costs are recovered from ratepayers. Second, TURN opposes SCE's efforts to overturn the Commission's longstanding requirement that shareholders bear 50% of the costs of Nuclear Energy Institute (NEI) trade association dues.

The combined impacts of TURN's adjustments are shown in the following table:

[922] Ex. SCE-16, p.82.

Palo Verde O&M - TURN adjustments to SCE forecast ($ thousands)	
	2025
SCE PVGS O&M Revenue Requirements (non-labor)	
Non-labor	82,780
Labor	324
less TURN Adjustments	
Reduce Recovery of NEI Dues by 50%	(132)
Reduce Non-Labor O&M by 6% for overcollection	(4,967)
Subtotal Impacts of TURN Recommendations	(5,098)
SCE PVGS O&M After TURN Adjustments	78,006

TURN provides support for these recommendations in the following sections.

24.6.1 Historical overforecasting justifies adjustments to PVGS ratemaking

SCE recovers practically all PVGS O&M costs as non-labor O&M since the facility is operated by Arizona Public Service on behalf of a consortium of owners (including SCE). In each GRC, SCE provides a forecast for the test year that is escalated in attrition years using the Commission-adopted Post Test Year Ratemaking mechanism.[923] As noted in TURN's original and errata testimony, SCE has historically recovered far more in customer revenues than it has spent on PVGS non-labor O&M.[924]

Based on SCE testimony and data responses, TURN calculates that total overcollections between 2018-2023 amount to $29.198 million (nominal) or 6.44% in excess of actual expenses. The following table shows overcollections (or undercollections) by year:[925]

[923] Ex. TURN-13-E, p.107.
[924] Ex. TURN-13-E, p.107.
[925] Ex. TURN-13-E, pp.107-108, Table 34. This table has been slightly modified to adjust the amounts collected in rates for 2019 and 2020 based on responses provided by SCE (Ex. TURN-103, SCE response to TURN Data Request 103, Q16).

PVGS non-labor O&M - authorized revenues v. recorded costs				
Year	**Collected in Rates**	**Actual Expenses**	**Actual - Collected (nominal k$)**	**Percent Overcollection (%)**
2018	82,716	77,085	-5,631	7.30%
2019	84,397	76,146	-8,251	10.84%
2020	86,753	73,106	-13,647	18.67%
2021	71,992	73,138	1,146	-1.57%
2022	75,184	74,700	-484	0.65%
2023	81,779	79,446	-2,333	2.94%
Total	**482,821**	**453,621**	**-29,200**	**6.44%**

The historic mismatch between SCE's forecast-based revenue requirements and its actual costs resulted in SCE shareholders retaining $29.198 million in excess funds. This gross overcollection should not be allowed to continue.

In rebuttal testimony, SCE asserts that the overcollections in 2018-2020 were the result of planned headcount attrition combined with the impacts of the COVID-19 pandemic.[926] It is not clear why SCE failed to accurately incorporate planned headcount reductions into the forecast applicable to 2018 and 2019 and whether similarly poor forecasting could recur over the current GRC cycle. The impacts of COVID on PVGS costs would only occur starting in 2020. Regardless of the reason, SCE was able to reap a windfall for its shareholders over the course of this entire period. SCE also tries to minimize its over-collection of $1.644 for 2021-2023 and implies that overcollections will not recur during the current GRC cycle but fails to provide any evidentiary basis for the Commission to reach this conclusion.[927]

[926] Ex. SCE-16, p.129.
[927] Ex. SCE-16, p.131.

In rebuttal, SCE attempts to introduce new 2024 "recorded" data to show the potential for an undercollection in the current year.[928] However, this information does not reflect recorded 2024 costs but rather the 2024 "budget" adopted by the PVGS co-owners prior to the start of the year.[929] In a data response to TURN, SCE admitted that "actual Palo Verde O&M Non-Labor expenses incurred during 2024 may vary relative to the budgeted expense."[930] The Commission should give little weight to the 2024 budget especially since current year recorded cost data is not being evaluated in this proceeding.

TURN recommends that the Commission address these consistent overcollections by reducing SCE's forecasted non-labor expense for PVGS by 6%.[931] This adjustment will bring SCE's cost recovery into line with actual PVGS O&M costs. As an alternative, the Commission could establish a balancing account to track actual PVGS operating costs and revenue collection related to PVGS non-labor O&M and refund any overcollections to customers.[932] To ensure that ratepayers have a degree of protection against unreasonable PVGS cost escalation, SCE should also be limited to recovery of no more than 110% of the forecasted costs for PVGS in any one year. If SCE's share of PVGS costs exceeds the 110% cap, SCE would have the opportunity to come to the Commission in the next GRC to demonstrate the reasonableness of the costs above the cap.

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[928] Ex. SCE-16, p.132, Table V-18.
[929] Ex. TURN-700, SCE response to TURN Data Request 117, Q59.
[930] Ex. TURN-700, SCE response to TURN Data Request 117, Q59.
[931] Ex. TURN-13-E, p.108.
[932] Ex. TURN-13-E, p.108.

24.6.2 The Commission should continue to require shareholders to pay for 50% of Nuclear Energy Institute dues

SCE asks the Commission to reverse its longstanding policy on trade association dues by allowing full rate recovery of dues paid to the Nuclear Energy Institute (NEI). SCE pays NEI dues through its partial ownership of PVGS and in its role as a majority owner of the San Onofre Nuclear Generating Station (SONGS). NEI dues payments relating to PVGS are authorized in the GRC while NEI dues relating SONGS are authorized in the Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). PVGS's total dues for NEI are $1.812 million and SCE's allocation of that amount (a 15.8% share) is $0.287 million.[933]

For PVGS, SCE originally requested 100% of its share of NEI dues in this case, apparently forgetting that it had argued in the last GRC that it should not recover the small portion of NEI dues classified as "lobbying expenses" along with "voluntary payments to the Foundation for Nuclear Studies".[934] SCE only recalled its prior position supporting exclusion of this portion of NEI dues from rate recovery after receiving data requests from TURN seeking clarifications on prior NEI dues payments.[935] For SONGS, SCE recently signed onto a settlement agreement that commits its shareholders to cover 50% of NEI dues attributable to the San Onofre Nuclear Generating Station (SONGS).[936]

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[933] Ex. TURN-13-E, p.104; Ex. SCE-WPSCE05V01S, p. 34.
[934] Ex. TURN-13-E, p.104; Ex. SCE-05v1, p.288; D.21-08-036, pp.365-366.
[935] Ex. TURN-13-Atch1, SCE response to TURN Data Request 80, Q32.
[936] Ex. TURN-13-E, p.104; Ex. TURN-13-Atch1, Joint Motion for Approval of Settlement Agreement Between SCE, SDG&E, A4NR, CalPA and TURN, A.22-02-016, Filed May 3, 2023, Section 6 (SONGS NEI fees). On May 29, 2024, the Commission issued a Proposed Decision that would adopt the settlement without modification.

TURN recommends that the Commission enforce its longstanding policy of requiring nuclear utilities to remove half the costs of NEI dues from rates. This adjustment would reduce PVGS non-labor O&M by $0.144 million in the 2025 Test Year.[937]

24.6.2.1 Historical Commission treatment of NEI dues

For the past two decades, the Commission has consistently adopted a 50/50 sharing of NEI dues between ratepayers and shareholders based on the recognition that the organization has a dual role of promoting nuclear power and working to cut industry costs. In D.06-05-016, the Commission first adopted TURN's recommendation to assign 50% of NEI dues to shareholders based on the fact that "the principle focus on NEI appears to be the advocacy of nuclear power, both nationally and globally."[938] The Commission found that "there are many aspects of such furtherance of the nuclear industry that may not be appropriate for ratepayer funding" and noted that SCE failed to provide information in its prepared testimony "on specific activities and related benefits that accrue to the company and/or ratepayers."[939]

Despite SCE's claims in that proceeding that all advocacy costs were included in separately disclosed lobbying expenditures, the Commission explained that "we are not convinced that all public policy advocacy costs are reflected as lobbying and excluded from SCE's forecast."[940] In the event that a different allocation of NEI dues is requested in a future GRC, the Commission directed SCE to "provide more detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits."[941] Absent such details, the

[937] Ex. TURN-13-E, p.107.
[938] D.06-05-016, p.35.
[939] D.06-05-016, p.35.
[940] D.06-05-016, p.35.
[941] D.06-05-016, p.35.

Commission determined that a 50/50 split of NEI dues between shareholders and ratepayers was reasonable.[942]

The following year, the Commission affirmed this treatment in a PG&E General Rate Case by approving a settlement with a 50/50 split of NEI dues.[943] In the intervening years since these two Decisions, no utility has come forward with a "detailed description" of NEI activities, costs and benefits to ratepayers that has resulted in a change to the 50/50 assignment of NEI dues.

This approach was further affirmed in SCE's 2009 and 2015 GRCs.[944] In the 2009 GRC, the Commission explained that

> SCE fails to establish that all the benefits of its NEI membership go to its customers. For instance, NEI engages in work that furthers the interests of the nuclear industry. Such work (for example, public relations and image advertising) may not be appropriate for ratepayer funding. SCE estimates that approximately 15% of membership fees are for these types of activities. Other work performed by NEI may benefit the industry rather than ratepayers. For example, DRA points out that "ratepayers should not be paying . . .to support NEI as it goes about '[s]tudying nuclear energy's intrinsic economic value to promote a general understanding of the value of nuclear power by policymakers and the public; and [b]uilding the next generation of nuclear power plants and technologies.'" SCE fails to address the amount of resources allocated to these types of studies. Accordingly, while SCE made further efforts to describe how the work performed by NEI benefits ratepayers, the extent to which NEI work benefits ratepayers versus the members of the nuclear generation industry remains unclear. We adopt DRA's recommendation to continue our policy set forth in D.06-05-016 of authorizing SCE to recover half of its share of NEI fees, $268,000.[945]

In SCE's 2018 GRC, the Commission found that SCE's submission of an Edison Electric Institute membership invoice providing guidance for allocating dues payments between shareholders and ratepayers was "insufficient evidence to establish the portion of the invoice

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[942] D.06-05-016, Finding of Fact 10.
[943] D.07-03-044, p.106.
[944] D.09-03-025, pp.12-13, D.15-11-021, p.16.
[945] D.09-03-025, pp.12-13.

which should be recovered from ratepayers."[946] Absent a clear demonstration of the portion of dues that support beneficial services provided to ratepayers, the Commission found that SCE failed to satisfy its burden of proof and limited ratepayer recovery to 50% of the costs.[947]

In its 2021 GRC, SCE again asked the Commission to reverse its policy and grant full recovery of NEI dues (net of lobbying expenditures) for PVGS. After reviewing TURN's opposition, the Commission denied SCE's request and reaffirmed the 50/50 split between ratepayers and shareholders.[948] In explaining the rejection of SCE's request, the Commission noted that "NEI engages in advocacy activities that extend beyond the activities classified as lobbying under Section 165(e)(1). It is unclear what portion of NEI membership dues fund these advocacy activities. It is also unclear to what extent ratepayers as opposed to the industry benefit from these advocacy activities."[949] In response to SCE's claim that NEI provides "substantial cost-savings benefits for customers", the Decision found that "SCE fails to establish that all the benefits of NEI membership go to ratepayers."[950]

There is no reason to deviate from the Commission's historic policy. As explained in the following sections, SCE fails to provide sufficient evidence to satisfy the standards laid out in prior Decisions and is unable to show the portion of NEI dues used to support various activities that may provide any ratepayer benefit. Evidence provided by TURN shows that NEI's commitment to industry promotion and nuclear power advocacy continues to be a major focus of its work.

[946] D.19-05-020, p.250.
[947] D.19-05-020, p.250.
[948] D.21-08-036, Findings of Fact 448, 449, 450.
[949] D.21-08-036, p.367.
[950] D.21-08-036, p.366.

24.6.2.2 SCE fails to identify the portion of PVGS NEI dues used to support different types of activities including advocacy and promotion

In this case, SCE makes another attempt to persuade the Commission to allow full recovery of NEI dues by offering a list of past NEI activities that may have yielded ratepayer benefits. SCE's direct testimony acknowledges that "many NEI members benefit from its lobbying and public policy advocacy functions" while asserting that NEI also provides many "functions that support nuclear plant operations", identifying some high-level categories of NEI work, and citing three historic initiatives undertaken by NEI that produced cost savings for nuclear facility owners.[951] SCE also provides a copy of the "NEI Member Value Overview" document prepared by NEI that lists past activities claimed to have yielded cost savings for various nuclear facility owners including activities "dedicated to supporting members".[952]

Amongst the benefits of NEI membership touted by SCE is access to the Personal Access Data System (PADS) that "is used to support decisions to grant, deny, or revoke unescorted access to the protected areas of operating nuclear power plants".[953] SCE fails to mention that access to PADS involves a supplemental contribution ($14,691 in 2024 for SCE share) collected outside of the base NEI dues.[954] Because this discrete expenditure clearly benefits PVGS and may lower costs for ratepayers, TURN does not oppose that supplemental contribution being fully recovered in rates.

TURN does not dispute that NEI provides services to its members, advocates for less burdensome federal regulations, and undertakes other activities intended to lower costs for

[951] Ex. SCE-05v1, pp.289-290.
[952] Ex. SCE-WP05v1, pp.341-345.
[953] Ex. SCE-05v1, p.290.
[954] Ex. TURN-700, SCE response to TURN Data Request 117, Q56

nuclear facility owners. However, NEI also devotes substantial resources to activities that are focused on industry growth, market development, export promotion, investor outreach and grassroots advocacy in favor of nuclear energy. SCE witness Cameron agreed that NEI devotes resources to public promotion of the benefits of nuclear energy, stating "I believe that's articulated on their website and in their mission statement".[955]

SCE did not provide a budget of NEI activities showing an allocation of costs by program area, a summary of membership dues received by different classes of members, or any other information that could be used to assess the relative use of resources for different functional organizational areas. When asked whether NEI provides any detailed budget information indicating expenditures by program area, SCE witness Cameron stated "I don't believe so, no."[956] Mr. Cameron further acknowledged that the only detailed information regarding NEI's budget provided to SCE comes in the form of its annual invoice of membership dues.[957] As shown in TURN's testimony, this invoice does not contain any budget or cost breakdown apart from showing total dues, voluntary contributions to the Foundation for Nuclear Studies, and the percentage of dues that NEI estimates are attributable to lobbying expenses pursuant to 6033(e) of the Internal Revenue Code.[958]

In rebuttal testimony, SCE pointed to the value provided by NEI in the form of "actively advocating for a waiver process…to allow Russian fuel currently in the supply chain to be used."[959] It appears that NEI's primary role in this effort was centered around the passage of Congressional legislation that banned Russian uranium imports but allows the Department of

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[955] Transcript, May 7, p.460.
[956] Transcript, May 7, p.459
[957] Transcript, May 7, p.460
[958] Ex. TURN-13-Atch1, SCE response to TURN Data Request 80, Q34, Attachment.
[959] Ex. SCE-16, p.123.

Energy to issue waivers under certain circumstances.[960] TURN does not believe that NEI's advocacy relating to Congressional legislation should be treated as a ratepayer-funded cost.

In rebuttal testimony, SCE acknowledges that NEI undertakes an array of activities on behalf of the overall nuclear power and technologies industry but asserts that "each NEI member only pays for the types of services it receives through its NEI membership" and references "a tiered schedule of membership dues" designed to accomplish this goal.[961] No additional information about "tiered" dues was provided by SCE. In response to TURN data requests, SCE conceded that NEI does not actually provide any breakdown of the services and benefits associated with each tier of membership dues.[962] Under cross examination, SCE witness Cameron (who authored SCE's rebuttal testimony) could not answer key questions regarding the system of "tiered dues", stated "I don't really have visibility to all the different sorts of memberships" and declined to "speculate" about the different tiers of membership.[963]

SCE further states that NEI dues for PVGS "do not pay for lobbying or advocacy that benefit other NEI constituencies such as advanced reactor design or nuclear medicine technologies."[964] SCE provided no specific documentation to support this claim. When TURN sought relevant written materials provided by NEI, SCE conceded that "NEI does not have any written prohibitions against using dues from one membership constituency to benefit another membership constituency."[965]

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[960] Ex. TURN-701, NEI Press Release ("NEI CEO Maria Korsnick on the Prohibiting Russian Uranium Imports Act"), Nuclear Newswire article ("Bill to Ban Russian Uranium Imports Heads to White House")
[961] Ex. SCE-16, p.125
[962] Ex. TURN-700, SCE response to TURN Data Request 117, Q57(a).
[963] Transcript, May 7, pp.462-463.
[964] Ex. SCE-16, p.126.
[965] Ex. TURN-700, SCE response to TURN Data Request 117, Q57(b).

SCE's testimony falls far short of the standard established by the Commission in past Decisions. Notably, SCE has not demonstrated what portion of NEI dues fund non-lobbying advocacy activities, the extent to which the benefits of NEI membership accrue to ratepayers versus the nuclear industry and investors, and a showing that "all the benefits of NEI membership go to ratepayers."[966] SCE's inability to provide this showing, along with opaque nature of NEI's programs and budgets, fails to justify a change in Commission ratemaking policy.

24.6.2.3 NEI's own materials demonstrate a significant commitment to ongoing advocacy outside the scope of "lobbying" that does not benefit ratepayers

A review of both public and confidential NEI materials demonstrates substantial ongoing advocacy that falls outside the limited scope of activities classified by the IRS as "lobbying." The portion of SCE's NEI dues attributable to "lobbying expenses" only includes spending covered by Internal Revenue Code §162(e)(1).[967] The IRS definition of lobbying is limited to activities designed to directly influence legislation, support a candidate for elected office, influence election outcomes, or involve direct communications with senior executive branch officials regarding agency actions.[968] The limited scope of activities classified as "lobbying" does not include any general advocacy outside of the specifics referenced in §162(e)(1). The NEI membership invoice for PVGS, which includes a percentage of dues attributable to "lobbying", does not demonstrate the portion of NEI's budget devoted to advocacy and industry promotion.

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[966] D.21-08-036, p.366.
[967] Ex. TURN-13-E, p.105; Ex. TURN-13-Atch1, SCE response to TURN Data Request 91, Q3(a) in A.19-08-013.
[968] 26 USC §162(e)(1).

TURN's testimony and attachments identify a range of NEI activities that focus on building support for the new and expanded use of nuclear energy through outreach to a range of organizations, efforts to engage the public, and strategies for shaping the overall narrative regarding the benefits of nuclear power.[969] NEI's website includes one section devoted to "the advantages of nuclear energy"[970] and another section describing NEI's efforts to promote the development and deployment of new ("advanced nuclear") plants.[971] Another focus of NEI's work is outreach to the financial community with the goal of encouraging investment in nuclear vendors and new plants.[972] The "Advocacy" portion of NEI's website focuses on efforts to promote exports of nuclear technology manufactured by domestic companies that are presumably NEI members.[973] NEI also funds a podcast named "Fissionary" that produces episodes explaining how nuclear energy can "solve the climate crisis and secure our energy independence".[974] Additionally, NEI recently announced a new "Generation" advertising campaign[975] designed to shift public opinion on nuclear energy and urging viewers to "choose nuclear energy".[976]

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[969] Ex. TURN-13-E, pp.105-106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.228-290.

[970] Ex. TURN-13-E, p.105 (referencing https://www.nei.org/advantages)

[971] Ex. TURN-13-E, p.105; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.245-249.

[972] Ex. TURN-13-E, p.105; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.235-240.

[973] Ex. TURN-13-E, p.105; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.229-231.

[974] Ex. TURN-13-E, p.106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF p.232.

[975] Ex. TURN-13-E, p.106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.233-234.

[976] Ex. TURN-13-E, p.106 (link to https://www.youtube.com/watch?v=EmFtgoVk0fA)

NEI's 2023 Annual Plan provides additional insights into the organization's basic programs but [redacted] The annual plan [redacted]:

[redacted][977] [redacted][978] [redacted][979] [redacted][980] [redacted]

[977] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 3.
[978] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 3.
[979] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 3.
[980] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 4.

[redacted][981] [redacted][982] [redacted][983] [redacted][984]

[redacted]

[981] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 4.
[982] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 4.
[983] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 4.
[984] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan Summary, page 4.

[redacted][985]

Nothing in the annual plan supports the Commission's requirement that SCE demonstrate that "all the benefits of NEI membership go to ratepayers."[986]

NEI's disclosures to the IRS show significant amounts of money spent annually on grants to advocacy groups and sponsorships of various events where policymakers gather.[987] NEI is a major contributor to Nuclear Matters (approximately $2 million per year in direct grants) which describes itself as "a national coalition of grassroots advocates, working to inform the public and policymakers about the clear benefits of nuclear energy."[988] Expenditures on Nuclear Matters are outside the definition of "lobbying" used by NEI. NEI's website urges visitors to join Nuclear Matters "to get updates and action alerts on how to preserve nuclear energy for future generations."[989] NEI also sponsors many conferences and provides direct grants to an array of organizations in an effort to gain support for the industry or obtain informal access to decisionmakers.[990] These grants and sponsorships are not included in the IRS definition of "lobbying" but are clearly an extension of NEI's advocacy work to promote the industry it represents which include vendors, manufacturers and plant owners (like SCE) that earn profits from their investments in existing facilities.

NEI's public and private materials demonstrate that its primary focus is the promotion of nuclear power, both domestically and abroad, and activities that are designed to develop a

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[985] Ex. TURN-13-Atch2C, NEI 2023 Annual Plan, page 38.
[986] D.21-08-036, p.366.
[987] Ex. TURN-13-E, p.106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.250-290.
[988] Ex. TURN-13-E, p.106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.241-242.
[989] Ex. TURN-13-E, p.106; Ex. TURN-13-Atch1, Section II (Nuclear Energy Institute Documents), PDF pp.243-244.
[990] Ex. TURN-13-E, p.106.

positive image for the industry. These activities are a central feature of NEI's operations, appear to be growing in scope and scale, and should be assumed to comprise a large portion of its budget. NEI does not provide a breakdown explaining the portion of its budget devoted to various types of advocacy, outreach, and public awareness activities. Neither SCE nor NEI have identified the portion of dues paid by individual nuclear facility owners that are allocated to the various programmatic areas of activity. Absent a far more comprehensive showing that answers these questions, there is no justification for abandoning the longstanding practice of a 50/50 split of NEI dues between shareholders and ratepayers.

25. ENERGY PROCUREMENT

25.1 Energy Procurement O&M

25.2 Energy Procurement Capital

26. ENTERPRISE TECHNOLOGY

26.1 Technology Planning, Design, And Support

26.2 Technology Delivery

26.3 Digital And Process Transformation

26.4 Service Management Office And Operations

27. OPERATING UNIT CAPITALIZED SOFTWARE

28. ENTERPRISE PLANNING AND GOVERNANCE (NON-INSURANCE)

28.1 Financial Oversight And Transactional Processing

28.2 Legal

28.3 Business And Financial Planning

Business and Financial Planning supports SCE's efforts "to develop, coordinate, and implement policies and practices that address federal and state regulatory and cost recovery requirements and related goals, as well as developing and managing business and financial operating plans and goals."[991] The Business Planning function within Business and Financial Planning "encompasses functions to perform integrated planning and financial forecasting for the enterprise," including "strategic planning, operations performance management, financial planning, and regulatory finance and economic forecasting."[992] SCE requests $36.532 million for the Business Planning function, including $28.196 million for labor and $8.336 for non-labor, which is an increase of $9 million over 2022 recorded costs ($27.520 million).[993] TURN takes issue only with SCE's non-labor forecast for Business Planning and recommends using 2022 last recorded year for non-labor ($5.263 million).[994] For the reasons provided below, the Commission should adopt TURN's Business Planning forecast of $33.459 million, which is $3.073 million less than SCE's request.

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[991] Ex. SCE-17V02, p. 41.

[992] Ex. SCE-06V03, p. 73.

[993] Ex. SCE-17V02, pp. 42, 47 (explaining that SCE reduced its original labor forecast by $0.701 million because it identified 5 positions that will no longer be needed).

[994] Ex. TURN-11 (Defever), pp. 3-4.

As TURN pointed out in testimony, SCE has consistently underspent on Business Planning non-labor since 2018, and SCE's recorded non-labor costs declined every year from 2018-2022.[995] The following table illustrates both of these trends.[996]

Business Planning - Non Labor (Constant 2022 $000s)					
	2018	2019	2020	2021	2022
Authorized	$16,126	$16,126	$16,126	$12,430	$12,430
Actual	$15,361	$13,137	$10,762	$9,750	$5,263
Underspent	$765	$2,989	$5,364	$2,680	$7,167

SCE has struggled to accurately forecast Business Planning non-labor costs in the past. In the 2018 GRC, the Commission reduced SCE's forecast for Business Planning by $8 million (2018 Constant $) to account for the wide variation in outside services consulting costs from 2011-2015.[997] In 2018, prior to the issuance of the 2018 GRC decision, D.19-05-020, SCE similarly incurred Business Planning expenses that were $8.0 million (in 2018 Constant $) or 18% less than SCE's GRC forecast.[998] In the 2021 GRC, the Commission authorized SCE's uncontested forecast for Business Planning, including $12.430 million for non-labor.[999] SCE underspent its forecast in 2021 primarily because the level of outside consultants was $4.575

[995] Ex. TURN-11 (Defever), p. 3.

[996] Ex. TURN-11 (Defever), p. 3. As noted in fn. 2 on page 3, the authorized amounts shown are test year authorizations without the increases provided through the post-test year adjustment mechanism authorized in the 2018 GRC for 2019 and 2020, and in the 2021 GRC for 2022.

[997] Ex. TURN-401 (Excerpt from SCE's 2021 GRC Testimony, SCE-06V02), p. 77 (discussing recorded costs for Business Planning in 2018 relative to amounts authorized in the 2018 GRC decision); D.19-05-020, pp. 251-252.

[998] Ex. TURN-401 (Excerpt from SCE's 2021 GRC Testimony, SCE-06V02), p. 77.

[999] Ex. SCE-06V03, p. 7 D.21-08-036, p. 386.

million lower than planned, which SCE attributes to "the general uncertainty in the COVID environment."[1000]

Given SCE's history of overforecasting non-labor costs for this activity from 2018-2022, the Commission should question the accuracy of SCE's forecast for 2025. Adopting the 2022 last recorded year as the non-labor forecast for Business Planning, as proposed by TURN, is reasonable in light of SCE's forecasting history and the consistent decline in non-labor spending from 2018-2022.[1001]

In rebuttal testimony, SCE argues that TURN overlooks the merits of SCE's adjustments to last recorded year in developing SCE's non-labor forecast. Those adjustments include an upward adjustment to maintain variable corporate consulting spend at 3-year historic levels as 2022 was atypically low, a reduction for reduced reliance on contingent workers, and an increase for consultants to support SCE's "reimagining the grid" and sustainability efforts.[1002] To the contrary, TURN considered these adjustments in its testimony but concluded that SCE's forecast was unreasonable because of its history of underspending and declining costs.[1003]

Moreover, it is unclear why SCE needs to retain a historical level of non-labor corporate consulting costs and add additional consulting support when SCE has requested to add

[1000] Ex. SCE-06V03, p. 77. SCE's forecasting inaccuracies took a different turn in 2023. SCE forecast non-labor costs of $8.156 million in 2023.[1000] This forecast was wildly inaccurate, as SCE spent $18.124 million in 2023 driven by $13.660 million in corporate consulting, which is $10 million higher than its forecast and exceeds non-labor expenditures every year since at least 2018. (Ex. SCE-06V03 WP, p. 199; Ex. SCE-11, Appendix A (2023 Recorded O&M); Ex. SCE-06V03 WP, p. 199; Ex. SCE-17V02, p. 46.).

[1001] D.04-07-022 (SCE 2003 GRC), p. 15 (quoting D.89-12-057) ("If recorded expenses in an account have shown a trend in a certain direction over three or more years, the [last recorded year] level is the most recent point in the trend and is an appropriate base estimate for [the test year].").

[1002] Ex. SCE-17V02, pp 45-46, referring to the adjustments discussed in Ex. SCE-06V03 at pp. 84-85.

[1003] Ex. TURN-11 (Defever), p. 4.

significant additional capacity and expertise to the Business Planning staff. SCE's labor request includes thirteen new positions in Business Planning, including nine additional staff who will provide "a commensurately resolute level of capabilities to fulfill our regulatory requirements, help ensure prudent resource management, and enable SCE to address evolving safety, reliability, financial, and compliance challenges in an increasingly risk-informed decision-making framework," and four additional staff "targeting longer term affordability, reliability and clean energy goals."[1004] This additional staffing, unopposed by TURN, should reduce the need for both types of consulting support reflected in SCE's upward forecast adjustments.[1005]

The Commission should find SCE's request excessive for all of these reasons. Accordingly, the Commission should adopt TURN's forecast of $33.459 million for Business Planning, which is comprised of SCE's forecast of $28.196 for labor and TURN's non-labor forecast of $5.263 million.

[1004] Ex. SCE-06V03, pp. 82-84; Ex. SCE-06V03 WP, p. 203. In rebuttal testimony, SCE reduced its labor request after identifying five positions "that will no longer be needed" due to "operational efficiencies." (Ex. SCE-17V02, p. 44). These positions do not appear to be among the thirteen new positions discussed in SCE's direct testimony and workpapers, as SCE has not revised its extensive discussion of these thirteen new positions through errata.

[1005] *See* Ex. SCE-17V02, pp. 84-85, as modified on p. 85-E4 ("The first adjustment relates to targeted use of consultants on complex strategic issues (including issues where the consultants' knowledge of and experience with other energy companies or wider best practices are invaluable) to address emerging issues. Historically, these costs have varied on a year-by-year basis. … Accordingly, the forecast for this category of non-labor spending is based on a 3-year average of $3.991 million."); p. 85 ("Incremental costs of $0.857 million for external consultants and EIX staff support are required to provide analytical support, company-wide coordination and expert knowledge on specialty areas that support California's key priorities around affordability, reliability and climate for electric customers, such as income-varying energy burden analysis, cost-benefit calculations for customer-adopted technologies, assessment of evolving reliability approaches and metrics, and analysis of new energy technologies. In addition, they will provide writing, editing and benchmarking support to prepare our annual sustainability report, assess the adoption of sustainability targets/metrics, and provide specialized services to track, manage and document sustainability data for compliance, reporting and operational purposes.").

28.4 Supply Chain Management And Supplier Diversity And Development

29. INSURANCE

29.1 Liability Insurance (Wildfire)

In D.23-05-013, the Commission adopted an agreement submitted in SCE's test year 2021 GRC proceeding to implement a self-insurance alternative for SCE's wildfire liability insurance coverage. TURN was a sponsoring party to that agreement, having reached the conclusion that under current market conditions a commitment to a self-insurance structure would better serve ratepayer interests than would continuing to rely on third-party commercial insurance products. TURN's prepared testimony here supported maintaining the self-insurance structure for wildfire liability claims rather than purchasing insurance products procured from third parties through the 2025 GRC period.[1006] On March 25, 2024, TURN joined with SCE and Cal Advocates in a motion requesting that the Commission approve and adopt an early decision in this proceeding extending the wildfire self-insurance program through the 2025 GRC period. On July 1, 2024, the Commission issued a proposed decision that would grant the joint motion without modification and is on the consent agenda for the July 11, 2024 meeting.

TURN very much appreciates the efforts of the ALJs and supporting staff whose efforts enabled preparation and issuance of this decision. With its issuance, there appear to be no further issues related to wildfire liability insurance that need to be addressed at this time in this proceeding.

[1006] Ex. TURN-15-E2, pp. 30-31.

29.2 Liability Insurance (Non-Wildfire)

TURN's prepared testimony challenged SCE's proposed forecast of $79.2 million for non-wildfire liability insurance expense in the 2025 test year, and instead recommended adoption of a forecast of $48.1 million based on the 2022 recorded expense.[1007] During the period between service of rebuttal testimony and the scheduled cross-examination on insurance-related issues, TURN, Cal Advocates and SCE successfully negotiated a proposed stipulation that, if adopted, would resolve all disputed non-wildfire insurance issues, including the non-wildfire liability insurance forecast amount.[1008] The proposed stipulation addresses the funding for non-wildfire liability and property insurance together, and would adopt a forecast of $82.27 million for all such costs (as compared to the combined forecast of approximately $104 million proposed by SCE, $67.8 million proposed by TURN, and $78.2 million proposed by Cal Advocates). The funding would also be subject to balancing account treatment through a new two-way General Liability & Property Insurance Balancing Account (GL&PBA).

The Commission should find the stipulation reasonable and adopt it without modification. While the forecast reduction as compared to SCE's request is not as large as TURN's testimony had called for, it represents a reasonable compromise of competing positions supported in the evidentiary record. And though TURN has called on the Commission to reduce its reliance on balancing and memorandum accounts as a general matter, TURN believes this new account is acceptable under the circumstances here and as part of the several compromises reflected in the stipulation.

[1007] Ex. TURN-15-E2, pp. 28-30.

[1008] Ex. SCE-34 (Stipulation of TURN, Cal Advocates and SCE on Non-Wildfire Insurance).

29.3 Property Insurance

TURN's prepared testimony challenged SCE's proposed forecast of $25.2 million for property insurance expense in the 2025 test year, and instead recommended adoption of a forecast of $19.6 million based on the 2022 recorded expense escalated by 10% per year.[1009] As described in the preceding section, the property insurance expense forecast is covered by the stipulation supported by TURN, Cal Advocates and SCE.[1010] For the reasons set forth in the preceding section, TURN urges the Commission to find the stipulation reasonable and adopt it without modification.

30. EMPLOYEE BENEFITS, TRAINING AND SUPPORT

The Commission should adopt TURN's adjustments to SCE forecasts for its Short-Term Incentive Program (STIP), Long-Term Incentives Program (LTIP), 401(k), Medical benefits programs, and training programs, which are summarized in the following table.

[1009] Ex. TURN-15-E2, pp. 26-28.

[1010] Ex. SCE-34.

Table 9: Summary of TURN Employee Benefits & Training Recommendations ($1,000s)

Category	2025		
	SCE	TURN	SCE > TURN
STIP*	120.406	73.447	46.958
LTIP	22.017	0	22.017
401(k) (Nominal$)*	132.041	126.895	5.146
Medical Programs (Nominal)*	153.788	132.919	20.869
Training Seat Time	37.023	28.511	8.512
Training Delivery	23.198	17.872	5.326
* In an email (02/21/24), SCE stated that TURN should rely on the fourth version of the RO Model for the Compensation and Benefits forecasts that it is including in the GRC. Here, tht includes the forecasts for STIP, 401(k), and Medical Programs, for which the reported SCE forecast is different than in SCE's Direct Testimony (see Ex. TURN-14-E2, pp. 9, 29, and 33).			

30.1 Employee Support

TURN, Cal Advocates and SCE reached a stipulation that reflects a complete resolution of disputed Employee Support issues, presented in Exhibit SCE-31. The Commission should find that this stipulation is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

30.2 Employee Benefits & Programs

30.2.1 Short-Term Incentive Program (STIP) and Executive Incentive Compensation Program (EICP)

SCE's forecast for the combined, Short-Term Incentive Program (STIP) and Executive Incentive Compensation Program (EICP) is $120.406 million.[1011] SCE refers to the STIP and

[1011] Ex. TURN-14-E2, Prepared Testimony of Garrick Jones Addressing Employee Benefits, Training & Support, Errata filed April 30, 2024, p. 9 (referencing RO Model (v. 1.4), O1) O&M Dashboard', 'STIP'

EICP interchangeably and forecasts the two programs as STIP. For consistency, TURN will refer to the programs and forecast as STIP in this brief. TURN's forecast reduces the STIP forecast by $46.958 million, for a forecast of $73.447 million. Please note that this 39.1% reduction should be applied to the RO Model calculation, given that SCE's STIP forecast will ultimately depend on reductions that the Commission makes to the labor force in its GRC decision.

Table 10: Summary of TURN's Recommendation Regarding SCE's STIP Cost Forecast ($1,000s)

Category	SCE	TURN	SCE > TURN
STIP	120,406	73,447	46,958

STIP is the annual variable pay program that gives employees and executives (through the EICP) an opportunity to earn a cash award based on achieving company goals and individual performance[1012] (with the second depending on the score achieved within the Individual Performance Modifier (IPM)[1013]). As explained in Exhibit TURN-14,

> (T)he amount that SCE pays in STIP in a given year, i.e., the STIP pool, is the sum of each eligible employee's STIP opportunity percentage multiplied by the employee's eligible earnings.[1014] The STIP pool is determined and fixed by the opportunity percentage (after possible modification based on the company's performance against STIP goals, called the Company Multiplier)[1015]) and eligible earnings. The STIP pool is not affected by IPM machinations.[1016]

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tab. In an email (02/21/24), SCE stated that TURN should rely on the fourth version of the RO Model for the Compensation and Benefits forecasts that it is including in the GRC.)

[1012] Ex. SCE-06 Vol. 4, p. 63:2-3.

[1013] Ex. TURN-14-E2, p. 10, referencing 2023 Short-Term Incentive Plan (pp. 2-3), provided as an attachment to DR TURN-SCE-009-1, provided in Ex. TURN-14-Atch1.

[1014] Id.

[1015] Id.

[1016] Id.

SCE also plans to convert a portion of its STIP compensation to Base Pay. TURN addresses the impact of this proposal Section 30.2.1.4 and Section 30.2.3.1 below.

30.2.1.1 Consistent with the Majority of Past Commission GRC Decisions, SCE Shareholders Should be Responsible for a Portion of STIP Costs because they Benefit from the Program

SCE's ratepayers should only be required to fund the STIP measures that primarily benefit ratepayers. If STIP measures are focused on shareholder benefits, shareholders should pay for the associated costs. STIP measures that provide benefits to both ratepayers and shareholders, should be paid for by both ratepayers and shareholders. This approach to STIP has been implemented by the Commission in numerous GRCs, including in Decision 14-08-032 where the Commission found it appropriate that "ratepayers bear reasonable costs for funding [ICP] metrics in relation to the benefits derived."[1017] In recent GRC Decisions, the Commission rejects the utilities' argument that ratepayers should fund 100% of their short-term incentive program as part of cost of service. As noted in Exhibit TURN-14, in SCE's last GRC (TY 2021), SCE argued that variable pay should be included in rates because it is an important element of an overall total compensation package that is at market.[1018] The Commission disagreed with SCE, explaining:

> [T]he Commission has repeatedly rejected arguments that cost-of-service ratemaking principles require ratepayers to fully fund incentive compensation where elements of the program essentially benefit shareholders without a clear demonstrable benefit to ratepayers, including in cases where the utility has argued that the total compensation package was at market.[citation omitted] The Commission has explained that "the sharing of cost responsibility promotes a reasonable matching of costs with benefits experienced both by ratepayers and

[1017] D.14-08-032, p. 522.

[1018] Ex. TURN-14-E2, p. 12, citing D.21-08-036, p. 428.

shareholders."[citation omitted] The Commission has also noted that it is within SCE management's discretion to target incentive compensation to achieve ratepayer benefits.[1019]

TURN's Testimony, Exhibit TURN-14, addressed how certain STIP measures partially, primarily, or exclusively benefit shareholders and accordingly should be wholly or partially funded by shareholders.[1020] TURN's recommendations for ratepayer funding levels for SCE's various STIP/EICP goals in summarized in the following table.

Table 11: Comparison of STIP/EICP Forecast, SCE versus TURN1021

STIP Goals	SCE		TURN	
	2023 Target Weight[1]	Forecasted Payout ($1,000s)	GRC-Recoverable Forecast Weight[2]	Forecasted Payout ($1,000s)
Safety & Resiliency	**55.0%**	**66,223**	**47.0%**	**56,591**
Covered Conductor	6.0%	7,224	3.0%	3,612
Capital Deployment	5.0%	6,020	0.0%	-
Remaining Safety & Resiliency Goals	44.0%	52,978	44.0%	52,978
Performance Mgmt & Op. Excellence	**45.0%**	**54,183**	**14.0%**	**16,857**
Core Earnings	25.0%	30,101	0.0%	-
Clean Energy Transition	4.0%	4,816	0.0%	-
Operational Excellence (Catalyst)	4.0%	4,816	2.0%	2,408
Remaining Performance Mgmt & Op. Excellence Goals	12.0%	14,449	12.0%	14,449
Total	100.0%	**120,406**	61.0%	**73,447**
		SCE > TURN ($1,000s) =>		**46,958**
[1] WPSCE06V04BkB, p. 10.				
[2] Justification for the reductions to the GRC-recoverable percentage can be found in the foregoing testimony.				

[1019] Id. Similar conclusions can be found for Sempra's 2012 GRC (*see* D.13-05-010 at p. 882) and PG&E's 2014 GRC (*see* D.14-08-032 at pp. 520-524).

[1020] See Ex. TURN-14-E2, pp. 13-22.

[1021] Ex. TURN-14-E2, Table 9, p. 23. See Table 10 for a summary of TURN's reductions based on intermediate steps included in TURN's overall STIP/EICP Recommendation.

30.2.1.1.1 Ratepayers Should Not Fund Goals that Primarily Benefit Shareholders

Core Earnings Goal (Performance Management and Operational Excellence Category, 25% of total STIP Target – TURN Ratepayer Funding Recommendation of 0%)

SCE's main argument in support of ratepayer funding for its Core Earnings Goal is "the financial health of the company is imperative to ensure SCE is able to attract investors and have access to capital for the direct benefit of its customers."[1022] While this may be true, SCE has not quantified this benefit, and it is not the metric by which achievement of this goal is measures. The Commission has also evaluated virtually the same argument before in the Sempra TY 2019 GRC, and found it unpersuasive:

> Applicants argue that the financial metrics provide benefits to ratepayers in the form of lower interest rates but we find that this is not substantiated or quantified by the evidence presented. We also find any benefit resulting from achieving Applicants' financial goals to be incidental and secondary to what we consider as the primary goal of the financial metrics which is to reach a certain level of income or earnings. After all, achieving a target interest level for borrowing is not one of the metrics that triggers the award.[1023]

As Decision 15-11-021 succinctly explains, "[The Commission] agree[s] with [utilities in] that financial performance may benefit ratepayers, [but] the ratepayer benefit is much less direct than the shareholder benefit. Further, in some instances, financial performance may be achieved at the detriment of ratepayers."[1024] TURN's testimony enumerates various ways earnings can be approved to the detriment of ratepayers, including:[1025]

[1022] Ex. SCE-06, Vol. 4, p. 65 & Ex. SCE-17, Vol. 3, p. 30.

[1023] D.19-09-051, p. 543.

[1024] D.15-11-021, p. 261.

[1025] Ex. TURN-14-E2, p. 14.

- the reduction of costs through work curtailment between rate cases accompanied by a subsequent attempt to convince the regulator to provide additional money for deferred work at the next rate case;

- development of infrastructure programs which may be of questionable value to ratepayers, but raise rate base;

- the election of tax-timing changes between rate cases that may benefit shareholders in early years at the expense of ratepayers in later years.

TURN also explains that "operating efficiencies" that can increase core earning are also not always directly beneficial to ratepayers,

> "… in cases where sustained and realized efficiencies are the means of improving earnings, shareholders benefit until the next rate case, at which point ratepayers presumably begin to benefit from such efficiencies. That is, ratepayers benefit to the extent such efficiencies and the resulting cost savings are included in the forecast for the next GRC, which is not always the case."[1026]

Further, as noted in Exhibit TURN-14, the Commission has long held that financial-based STIP goals, such as SCE's Core Earnings STIP goal, are inappropriate for inclusion GRC-based revenues. In SCE's last GRC (TY 2021), the Commission agreed with TURN that 100% of financial goals should be disallowed, the Commission stated,

> "As in past GRCs, we continue to find that this goal is primarily intended to benefit shareholders.[citation omitted] The goal may or may not result in secondary benefits to ratepayers since a goal of "achieving core earnings" does not always align shareholder and ratepayer interests."[1027]

The Commission also disallowed ratepayer funding for the "financial goals metric" in D. 23-11-069 addressing PG&E's TY 2023 GRC.[1028] SCE's Rebuttal Testimony does not offer any new arguments or facts to justify the Commission modifying its long standing policy that financial-based STIP goals should be funded by shareholders.

[1026] Id.

[1027] D.21-08-036, pp. 431-432.

[1028] D.23-11-069, p. 609.

Capital Deployment Goal (Safety & Reliability Category, 5% of total STIP Target – TURN Ratepayer Funding Recommendation of 0%)

SCE describes the Capital Deployment STIP goal as being related to the execution of grid, technology, electrification, and other improvements to deliver safe, reliable, clean, and affordable energy for customers, while achieving CPUC and FERC jurisdictional capital improvement plan execution, consistent with appropriate regulatory direction.[1029] As noted in Exhibit TURN-14, SCE has an authorized Return on (Common) Equity (ROE) of 10.05% and its total, authorized rate of return is 7.44%.[1030] As a result of this rate of return on capital spending, this goal directly benefits shareholders, regardless of the whether the investment is "consistent with appropriate regulatory direction".

Further, this goal is largely duplicative of the financial goal of the STIP and the LTIP, as it incentivizes capital expenditure, which is the primary driver of EIX share performance. As discussed in TURN's testimony, EIX states that the 2025 Core earnings per share (EPS) growth estimate is driven by the 11–14% 2025 rate base growth.[1031] Further, the existence of such a goal could potentially encourage undue focus on capital-intensive solutions in both SCE's regulatory and asset-management approaches, which could be detrimental to ratepayers, as ratebase growth is one of the key factors leading to the current utility rate affordability crisis.[1032]

[1029] Ex. WP SCE-06, Vol. 4, BkB, p. 10.

[1030] Decision 22-12-031, p. 1.

[1031] Ex. TURN-14-E2, p. 18. Referencing *Fourth-Quarter And Full-Year 2023 Financial Results* (Presentation) (p. 15), February 22, 2024. Presentation is in included in Ex. TURN-14-Atch1.

[1032] Ex. TURN-02E, pp. 4-6 & FN 19 referencing CPUC, "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), p. 7.

Exhibit TURN-14 provided some examples of how this incentivization of capital spending could occur as a result of this goal:

> Management may be incentivized to prefer capital-intensive solutions at the expense of O&M solutions when recommending solutions to such issues as wildfire before the Commission and when selecting management solutions in the field (e.g., a preference for undergrounding of facilities or covered conductors at the expense of a well-managed vegetation management solution when evaluating how to approach the wildfire implications of a particular wire).[1033]

For the foregoing reasons, ratepayers should not fund the cost of the Capital Deployment STIP goal. The Commission should apply its long standing policy that financial-based STIP goals should be funded by shareholders to this goal.

Clean Energy Transition (Performance Management and Operational Excellence Category, 4% of total STIP Target – TURN Ratepayer Funding Recommendation of 0%)

SCE describes the Clean Energy Transition as a goal to "[a]dvance electric technology adoption to enable emissions reductions across economic sectors [by a]dvanc[ing] SCE's clean energy pathway objectives [of] Transportation Electrification (TE) charging port installations … and medium/heavy duty electric vehicle conversions … [and] Building Electrification (BE) heat pump installs … ."[1034] Similar to the Capital Deployment goal discussed above, shareholders derive more benefits from this capital-deployment-focused goal than ratepayers. While supporting TE and BE is consistent with California's climate change mitigation targets, the investments incentivized in this goal come with significant capital spending that SCE's shareholders will earn a rate of return on for decades to come.[1035] Exhibit TURN-07 also

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[1033] Ex. TURN-14-E2, p. 17.

[1034] Ex. TURN-14-E2, p. 18. Referencing *Fourth-Quarter And Full-Year 2023 Financial Results* (Presentation) (p. 15), February 22, 2024. Presentation is in included in Ex. TURN-14-Atch1.

[1035] See Ex. TURN-07E (Ashford) for a discussion of the significant capital expenditures SCE forecasts to support transportation electrification load growth.

highlights issues with SCE's over-forecasting for new TE load, indicating that SCE employees do not necessarily need to be incentivized to meet this goal.[1036] Further, as addressed in the Section 4.2.2 of this brief, much of the TE related spending is designed to support medium/heavy duty electric vehicle fleets owned by large corporations who will eventually reap financial benefits from electrification; but the grid upgrades are funded by all SCE customers, including residential ratepayers, many of whom are struggling to afford necessary electric service. Asking SCE ratepayers to fund incentive payments for SCE executives to encourage more capital spending adds to this inequity.

Exhibit TURN-14 addresses other policy issues with this goal.[1037] For the foregoing reasons, the Commission should find this goal primarily benefits shareholders, and is not appropriate for ratepayer funding.

30.2.1.1.2 The Cost of the Following Goals Should be Reduced Based on their Benefits to Ratepayers

TURN identifies the following goals that are constructed in such a way that they are contrary to, or do not primarily or only partially support ratepayer goals, and accordingly should not be fully funded by ratepayers.

Covered Conductor (Safety and Resiliency Category, 6% of total STIP Target – TURN Ratepayer Funding Recommendation of 3%)

The Covered Conductor STIP goal is based on the annual number of covered conductor circuit miles installed.[1038] Similar to the Capital Deployment goal discussed above, it is

[1036] Ex. TURN-07-E, pp. 6-20.

[1037] Ex. TURN-14-E2, p. 18.

[1038] Ex. WP SCE-06, Vol. 4, BkB, p. 10.

generally inappropriate for ratepayers to fund capital-deployment-focused goals as these goals provide significant benefits to shareholders. However, the Covered Conductor STIP goal is more appropriate for some ratepayer funding than the other capital deployment goals (i.e., general Capital Deployment and Clean Energy Transition) as "it is combined with a suite of other Wildfire-related goals that comprise a results-oriented goal (i.e., CPUC reportable ignitions) and several O&M-related goals that seem to work in concert with the strictly capital-related goal of Covered Conductors."[1039]

Exhibit TURN-14 discusses examples of SCE touting the rate base growth benefits of wildfire mitigation work to its shareholders:

> It is important to note that the utility views the capital investment in wildfire (and clean-energy transmission) with enthusiasm in its earnings calls, stating, "Projected ~6–8% rate base growth 2023–2028; substantial additional investment opportunities offer upside[.] Strong rate base growth driven by wildfire mitigation and important grid work to support California's leading role in clean energy transition. … 2025 Core EPS growth primarily driven by rate base earnings." Furthermore, on a page on which SCE discussed its double-digit total return potential with investors, the only specific utility activities that SCE raised were wildfire mitigation and electrification, both capital-intensive programs and the only programs for which Edison codifies capital-program specific, STIP goals.[1040]

SCE does not specifically address this evidence in its rebuttal testimony, and generally argues that in regards to capital deployment goals, "… shareholder and customer interests are aligned …".[1041]

[1039] Ex. TURN-14-E2, p. 19.

[1040] Id. Referencing *Fourth-Quarter And Full-Year 2023 Financial Results* (Presentation) (p. 12 & 18), February 22, 2024. Presentation is in included in Ex. TURN-14-Atch1 (Attachment 2).

[1041] Ex. SCE-17, Vol. 3, p. 32.

For the Covered Conductor goal, TURN agrees with SCE that shareholder and ratepayers both benefit, and accordingly shareholders and ratepayers should evenly share the cost of the Covered Conductor goal. This cost sharing acknowledges the shareholder benefits of this goal which SCE touts to investors, and the wildfire mitigation benefits the goal provides to both shareholders and ratepayers.

Operational Excellence (Performance Management and Operational Excellence Category, 4% of total STIP Target – TURN Recommendation of 2%)

SCE describes the Operational Excellence goal as a goal to "[e]xecute continuous improvement efforts for Catalyst Program [by i]mplementing … planned improvement projects."[1042] It is appropriate to share the cost of payments on this goal at 50%/50% between ratepayers and shareholders. In theory any operational efficiencies that are implemented on a lasting basis benefit ratepayers to a certain degree, however, TURN's testimony raised two issues with this goal that require further consideration.

First, shareholders reap the rewards for efficiencies found after the GRC application is filed. While such efficiencies will eventually be recognized in the revenue requirement when the subsequent GRC is filed, shareholders will reap the rewards for up to four years during the GRC cycle. Exhibit TURN-14 noted that this concept is exemplified in SCE's Chief Financial Officer (CFO)'s prepared remarks in the 2023 Fourth Quarter earnings report,

> "[O]ur operational excellence initiatives are off to a solid start, and we are seeing this translate into higher operating efficiency throughout the business. This was reflected in better-than-expected SCE operational variances."[1043]

[1042] Ex. WP SCE-06, Vol. 4, BkB , p. 10.

[1043] Ex. TURN-14-E2, p. 20, referencing Prepared Remarks of Edison International CEO and CFO Fourth Quarter and Full Year 2023 Earnings Teleconference February 22, 2024, 1:30 p.m. (PT) (p. 4), The

The second issue raised by TURN is that "O&M efficiencies create new opportunity for management to offset higher capital spending, perhaps making such expenditures more palatable for customers and the regulator."[1044] Exhibit TURN-14 presents examples of this, including multiple remarks for SCE executives regarding the value of the operational excellence program to shareholders.[1045] Accordingly, shareholders and ratepayers should evenly share the cost of the Operational Excellence (Catalyst Program) goal, recognizing that shareholders benefit at least as much as ratepayers as the result of operational efficiency.

30.2.1.2 Any Reduction that the Commission Adopts for STIP Should be Fully Recognized and Not Cut in Half

SCE observes and argues the following in its Direct Testimony regarding how much of the reductions that the Commission adopts for any particular STIP goal should be reflected in a reduced forecast:

> The STIP or EICP payout equals the target payout for the employee times the corporate multiplier and the employee's individual performance multiplier. Since the individual performance multiplier has the same impact on the STIP or EICP payout as the corporate multiplier, any disallowance for a particular Corporate Goal should be cut in half to reflect that the weighting of the Corporate Goal only applies to the corporate multiplier and not to the individual performance multiplier [(IPM)]. Any further reduction on the incorrect assumption that SCE employees' daily work can somehow be balkanized into customer-versus-shareholder benefit devalues and distorts the work that SCE's hard-working employees accomplish.[1046]

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prepared remarks and the associated slideshow from the fourth-quarter and full-year 2023 earnings call are included in Ex. TURN-14-Atch1 (Attachment 2).

[1044] Ex. TURN-14-E2, p. 20.

[1045] Ex. TURN-14-E2, pp. 20-22.

[1046] Ex. SCE-06, V04, p. 53.

As found in Exhibit TURN-14-E2, SCE's recommended approach, that the Commission cut any reduction to STIP funding in half in order to avoid balkanizing employees' daily work into customer-versus-shareholder benefit, is fundamentally flawed.[1047] The amount that SCE pays in STIP in a given year, i.e., the STIP pool, is wholly determined by the company's performance against STIP goals and is not affected by IPM machinations.[1048] In fact, as noted in TURN-14-E2, the IPM is a zero-sum game across the company.[1049] SCE's STIP specifically states:

> Once the company allocates an organization's STIP award pool, that pool is fixed. This means that if an organization's leadership wants to fund IPM amounts more than 100 percent for its high performing exempt Eligible Employees, such as those in Pay Zones 6 and 5, they must shift funds away from exempt Eligible Employees in lower Pay Zones. Depending on the number of high performers in an organization, this could mean that exempt Eligible Employees in Pay Zone 4 and below may receive less than 100 percent of their STIP Opportunity.[1050]

As such, given that the total STIP payout is directly and only affected by the STIP Pool, which is, in turn, a product of the STIP goals multiplied by employee Base Pay,[1051] the Commission would be correct to adopt reductions to STIP based on a 100% accounting of any reductions it makes to individual goal percentages.

SCE's attempt to rebut TURN's position adds little new information – the company essentially simply repeats the contention that because of the presence of the IPM at the individual employee level, the Commission should simply disregard the fact that the STIP pool

[1047] Ex. TURN-14-E2, p. 24.

[1048] Id.

[1049] Id.

[1050] Id., referencing pp. 3-4 of SCE's 2023 Short-Term Incentive Plan.

[1051] Id.

as a whole is determined by company performance against company STIP goals[1052] – except for its acknowledgement that TURN is correct in its assessment that the IPMs are a zero-sum game across the company.[1053] SCE's conclusion regarding how to treat the zero-sum nature of the IPMs, however, is incorrect. The utility reiterates its hope that the Commission will focus on the fact that the IPM can significantly impact the STIP payout calculation for the individual employee and ignore the fact that the STIP payout, generally – the amount that the GRC is intended to forecast – is based solely on the SCE performance against company-wide goals. The IPM, as the name suggests, is nothing more than a modifier for each individual employee and in no way impacts the amount of STIP that the company will payout to the body of employees as a whole in a given year. The foregoing makes it clear that the Commission should disregard SCE's argument that any disallowance for a particular Corporate Goal should be cut in half.

30.2.1.3 The Commission Should Make its Reductions to SCE's Forecast Based on 2023 STIP Goals

SCE requests in its Rebuttal Testimony that the Commission "make any reductions [to the STIP forecast] based on the 2024 SCE goals and allocations … [rather than the 2023 goals and allocations, based on the idea that] STIP goals for TY 2025 will be developed using the 2024 goals as a starting point… [and will t]herefore … be more reflective (as compared to the 2023 goals) of what the 2025 goals are likely to be".[1054] Parties were not privy to SCE's STIP goals and allocations during the pendency of SCE's case in chief. Instead, the workpapers that support

[1052] Ex. SCE06, V04, pp. 36-38.

[1053] Id., p. 38.

[1054] Ex. SCE17, V03, pp. 38-39.

SCE's Direct Testimony, the workpapers that TURN relied upon,[1055] identified the goals and allocations for 2023.[1056] Information from 2023, therefore, is the only information that TURN was able to evaluate during its case in chief and should be the information upon which the Commission bases its STIP deliberations in this case. Precedence for TURN's approach comes from SCE's 2021 GRC, where the Commission found the following:

> Our review of the STIP/EIC goals is based on SCE's 2019 goals, which SCE presented in its direct testimony in support of its funding request and which intervenors had the opportunity to analyze and address in their testimony. SCE notes that it subsequently revised its goals for 2020. Because management has the discretion to change the goals and weightings each year, it is unclear that the 2020 goals would necessarily be more representative of the goals for 2021-2023. Moreover, since SCE presented these revised goals in rebuttal testimony, other parties did not have the opportunity to present testimony on the revised goals and there is a lack of detail in the record regarding the 2020 goals compared to the 2019 goals. (Footnote omitted)[1057]

TURN submits that the Commission should use analogous reasoning in the instant case and use 2023 goals and allocations, contrary to SCE's request to use those from 2024.

30.2.1.4 The Commission Should Adopt a Base Pay Conversion Reporting Mechanism

Regarding SCE's plan to convert a portion of its STIP compensation to Base Pay, TURN originally recommended a reporting and clawback mechanism to track and return funds to ratepayers.[1058] In Exhibit SCE 17, Volume 3, SCE argued that the clawback mechanism was unnecessary because "SCE has already completed two of the three phases for its STIP to base pay transition and has extensively communicated to employees that the third phase will go into

[1055] Ex. TURN-14-E2, p. 23.

[1056] Ex. WP SCE-06, Vol. 04 BkB, p. 10.

[1057] D.21-08-036, p. 431.

[1058] Ex. TURN-14-E2, p. 25.

effect the first pay period of 2025."[1059] In light of this information, TURN agrees the clawback mechanism is unnecessary and rescinds that proposal. SCE indicated that it does not oppose TURN's reporting mechanism proposal to submit "an advice letter to show the conversion occurred and to inform the Commission to any additional adjustments to SCE's STIP targets."[1060]

SCE disagrees with TURN's recommendation that a Tier 2 advice letter be used for this reporting mechanism. However, TURN continues to recommend a Tier 2 advice letter be adopted for this reporting mechanism.

30.2.2 Long-Term Incentive Program (LTIP)

The Commission should again deny SCE's request to have ratepayers fund any portion of its Long-Term Incentive Plan (LTIP) costs. SCE's LTIP provides stock options and performance shares,[1061] to executives and "non-executive principal-level employees, attorneys, and some project managers."[1062] The Commission has consistently denied SCE's request for rate recovery of costs associated with LTIP since at least the 2009 GRC.[1063]

In its most recent rejection of SCE's request, noting SCE's standard defense that its overall compensation is at market, the Commission stated,

> We continue to find that LTI is primarily designed to reward SCE employees for promoting shareholder interests. … LTI is closely tied to the stock performance of EIX since LTI awards take the form of equity in EIX. … SCE's arguments that that reconsideration of this issue is merited in light of AB 1054 are not convincing. … [W]e see no reason to discontinue our longstanding policy of

[1059] Ex. SCE-17, Vol. 3, p. 43.

[1060] Id. at p. 44.

[1061] Ex. SCE-17, Vol. 3, p. 53.

[1062] Ex. SCE-17, Vol. 3, p. 67.

[1063] D.09-03-025, pp. 134-135; D.12-11-051, p. 452; D.15-11-021, p. 266; D.19-05-020, p. 188.

> denying ratepayer recovery for LTI. Therefore, SCE's request to include these costs in rates is denied.[1064]

As TURN addressed in Testimony, SCE's justifications for LTIP rate recovery in the present GRC primarily rely on the same arguments which the Commission has consistently found uncompelling in the past to support ratepayer funding,[1065] including SCE's repeat attempt to rely on AB 1054 to support the inclusion of its LTIP request in rates.[1066]

The Commission should once again find SCE's arguments regarding AB 1054 unconvincing. There is nothing in the statutes implementing AB 1054, or SCE's proposed approach to responding to its requirements, that warrants a change to the Commission's long-established policy of disallowing utilities' LTIP. Accordingly, the Commission should deny SCE's $22.017 million LTIP forecast.[1067]

30.2.3 401(k) Savings Plan

SCE forecasts a test-year expense of $132.041 million (nominal $) for the 401(k) Savings Plan costs.[1068] To prevent the unsupported upward adjustment to the 401(k) Savings Program owing to the STIP-to-Base Pay conversion, TURN removes the upward adjustment that results from the 2022 Labor (i.e., Base Pay) restatement (after further adjusting it for escalation) from the 2025 Labor (i.e., Base Pay) forecast and multiplies the result by the 2022, 401(k)-to-Labor

[1064] D.21-08-036, pp. 423-424.

[1065] Ex. TURN-14-E2, p. 29.

[1066] Ex. SCE-06, Vol. 4, p. 70.

[1067] Ex. SCE-06, Vol. 4E3, p. 67-E3.

[1068] Ex. TURN-14-E2, p. 29 (references "RO Model O1) O&M Dashboard", "401(k)" tab. This amount is different than the amount stated in SCE's testimony (i.e., $122.609 million, per Ex. SCE06V04, p. 100:7-8). SCE states that TURN should rely upon the value from the workpapers (email from SCE, dated February 21, 2024)).

(i.e., Base Pay) ratio of 11.54%.[1069] This results in a downward adjustment to the 401(k) forecast of $5.146 million for a forecast of $126.895 million.[1070] In constant-dollar terms, TURN's forecast is $113.297, which represents a $4.595 million reduction to SCE's $117.892 million forecast.[1071] Please note that this 4% reduction[1072] should be applied to the RO Model calculation, given that SCE's 401(k) Program forecast will ultimately depend on reductions that the Commission makes to the labor force in its GRC decision.

30.2.3.1 The STIP-to-Base Pay Conversion Causes an Unreasonable and Unsupported Increase to SCE's Total Compensation

The 401(k) Savings Plan is a defined-contribution savings plan, which provides employees an opportunity to defer current income to save for future financial needs. The cost of the program to SCE is the result of the company's policy of matching employee contributions on a dollar-for-dollar basis up to 6% of the employees' Base Pay.[1073] As identified in SCE's Direct Testimony, SCE proposes to move a portion of the STIP compensation to Base Pay for various policy reasons.[1074]

As noted in Exhibit TURN 14-2E, the nature of SCE's policy for matching 401(k) contributions on a dollar-for-dollar basis up to 6% of Base Pay is mechanical and arbitrary. SCE derives the forecast for its contributions to the 401(k) program by multiplying the test-year, Base

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[1069] "RO Model O1) O&M Dashboard", "401(k)" tab.

[1070] Ex. TURN-14-E2, pp. 29-30.

[1071] Id., p. 30.

[1072] I.e., $5.146M / $126.895M.

[1073] Ex. SCE06V04, p. 101:6-7.

[1074] Ex. SCE06V04, pp. 45-49.

Pay forecast by the ratio of 2022 recorded program costs to 2022 recorded labor (i.e., Base Pay) costs.[1075] Doing so, however, increases the total compensation level that it pays employees because the recorded, 2022 ratio is multiplied by a higher base pay because of the STIP-to-Base Pay Conversion, which results in an increase of $44.591 million increase to the 401(k)-contribution forecast.[1076] Therefore, while the STIP-to-Base Pay conversion is ostensibly a simple conversion of pay from one component to another, it has the effect of causing an increase to SCE's total compensation based on the mechanics that SCE uses to effect the change.

The evidence of the increase to the 401(k) forecast as a result of the STIP-to-Base Pay Conversion is not in dispute.[1077] The only question before the Commission is whether the increase is reasonable. TURN submits that SCE has not provided any justification that overall compensation should increase, as noted in Exhibit TURN-14-E2.[1078] In addition, Edison's Total Compensation Study results show that the company's compensation is already at market, which further shows that an increase is unnecessary.[1079]

The method for calculating the 401(k)-contribution forecast is arbitrary and, as described in Exhibit TURN-14-E2, can and should be adjusted such that the absolute amount of 401(k) contribution, and therefore the total compensation, remains consistent with the levels prior to the STIP-to-Base Pay conversion. As such, TURN reduces the 401(k) contribution forecast so that it is consistent with the STIP target percentages prior to the STIP compensation transfer to the

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[1075] Id., p. 109:1-2. What SCE refers to as the "labor" forecast can also be referred to as the "Base Pay" forecast.

[1076] Ex. TURN-14-E2, p. 30.

[1077] Ex. SCE06, V04, p. 103:FN 181 and SCE17, V03, pp. 66-67.

[1078] Ex. TURN-14-E2, p. 32.

[1079] Ex. TURN-14-E2, p. 32.

Base Pay compensation component, as discussed in Exhibit TURN-14-E2.[1080] As illustrated in Exhibit TURN-14-E2, this is a ratemaking adjustment and does not affect SCE's employees' total compensation when the pre- and post-compensation-conversion compensation levels are compared. SCE is free to reduce the company's 401(k) match percentages, as it sees fit, but, if it were to reduce the percentage and maximum match, the action would maintain, rather than reduce employee total compensation vis-à-vis the total compensation prior to the STIP-to-Base Pay conversion.[1081]

To counter the fact that the mechanical and arbitrary nature of the 401(k) contribution in combination with the STIP-to-Base Pay conversion contributes to an unreasonable increase to SCE's compensation level, SCE argues in its Rebuttal Testimony that "as it has in the past, [the company] used the Results of Operation (RO) Model to forecast the 401(k) company contribution" and it "reflects the "employee compensation program"… ."[1082] However, the simple fact that SCE uses the RO model to forecast the 401(k) company contribution does not mean that SCE's policy for matching the 401(k) contribution at 6% is not mechanical and arbitrary or that, in combination with the proposed STIP-to-Base Pay Conversion, such fact contributes to an overall increase in compensation. SCE further argues in its Rebuttal Testimony that it is "perfectly reasonable that the 2025 labor forecast used to calculate 2025 401(k) costs

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[1080] Ex. TURN-14-E2, p. 31-33.

[1081] Id., p. 31. TURN understands that by the time this issue is decided by the Commission that the company likely would have implemented the compensation transfer, likely without a reduction of 401(k) matching percentages. This is correctly viewed as a matter that is internal to SCE (and could have been avoided with a more proactive and transparent methodology to make the conversion-component transfer truly just a transfer). The likelihood that SCE would already have implemented the conversion should not be relied on as reason not to apply the correct methodology for the transfer given the evidence that SCE has provided.

[1082] Ex. SCE17, V03, p. 66.

includes the base pay increase from the STIP to base pay transition"[1083] because, in part, "the 2025 401(k) forecast reflects the costs resulting from market average base pay."[1084]

SCE further argues that the company's STIP-to-Base Pay conversion simply fixes what is currently a competitive disadvantage and that SCE's proposal strives to help the company "pay market average base pay".[1085] Just because base pay may be less than market does not mean that the company should arbitrarily increase total compensation when it is not warranted on the basis of the Total Compensation Study (TCS). As aforementioned, the TCS, which was conducted prior to the STIP-to-Base Pay Conversion, found that SCE's total-compensation package is already at market. The competitive disadvantage that SCE complains about is relative to Base Pay, not overall compensation,[1086] which renders the ancillary impact to total compensation owing to an increase to 401(k) compensation on the basis of an increase to Base Pay unsupported and unreasonable. SCE contends that the total compensation is 0.6 percent below the market average, and that the increase in 401(k) company contributions from STIP to base would not have brought SCE's actual total compensation to the market average.[1087] However, the TCS, itself, already noted that SCE's compensation was at market, despite being 0.6 percent below market, given that it was within +/- 10% of market.[1088] In any case, SCE hardly mentioned, and did not attempt to justify the forecasted increase to the 401(k)-contribution cost as the result of

[1083] Id.

[1084] Id.

[1085] Id.

[1086] Ex. SCE-06, V04, p. 47.

[1087] Ex. SCE-17, V03, p. 67.

[1088] Ex. TURN-14-E2, p. 35.

the STIP-to-Base Pay Conversion. The Commission should not allow this unsupported increase in total compensation.

30.2.4 Medical Program

SCE contributes to employee medical coverage under Medical Programs.[1089] TURN summarized SCE's forecasting methodology in Exhibit TURN-14.[1090] TURN takes issue with SCE's proposal to add 16% to its forecast to account for a new Premium-Sharing Redesign.[1091] The new premium-sharing design includes a reduction to the employee share of (i) healthcare premiums across all medical plans and (ii) select medical-plan co-pays and out-of-pocket costs, as well as, (iii) implementation of a standard/closed prescription drug formulary for the pharmacy program offered by Express Scripts.[1092]

SCE justifies the premium-sharing redesign by comparing its current contribution to employee medical benefits to PG&E's[1093] and asserting that the "changes are necessary to bring employee costs back within market benchmarks and stay competitive in a tight labor market."[1094] SCE's assertion that its Medical Programs contribution is below market ignores the fact that its benefits program, generally, is at 20% above market, well above what other market participants receive and its overall compensation program has been found to be at-market.[1095] SCE has provided no justification for an increase to its contribution to medical costs in light of the

[1089] Ex. SCE- 06, Vol. 4, p. 114.

[1090] Ex. TURN 14-E2, pp. 33-34.

[1091] Ex. SCE- 06, Vol. 4, p. 120.

[1092] *Id.,* p. 118.

[1093] *Id.*

[1094] *Id.*

[1095] Ex. SCE- 06, Vol. 4, pp. 44-45.

existing, generous overall benefits package and a total compensation package that SCE and its compensation consultant has found to be at-market. Accordingly, the Commission should remove the 16% upward adjustment that SCE includes for the Premium-Sharing Redesign, which results in a reduction of $20.866 million to SCE's $153.788 million forecast on a nominal basis. On a constant-dollar basis TURN's forecast recommendation is $113.198 million for a reduction of $17.770 million. Please note that this 16% reduction should be applied to the RO Model calculation, given that SCE's Medical Programs forecast will ultimately depend on reductions that the Commission makes to the labor force in its GRC decision.

30.2.5 Pensions

The Commission should maintain the "historical funding policy" and authorize a pension expense of $17 million, rather than adopt the "new funding policy" SCE proposes, with its $44.9 million forecast.

SCE's "historical funding policy" has been in place since at least 1982.[1096] In recent years, the combination of investment returns and ongoing ratepayer-funded contributions (the Pension Plan's only funding sources[1097]), have produced a pension asset that is slightly overfunded – that is, the asset exceeds the present value of all benefits earned to date. In the 2021 GRC, using the historical funding policy resulted in a authorized pension cost forecast of $84.3 million per year.[1098] Maintaining the historical funding policy through this test year 2025 GRC period would result in an authorized pension cost forecast of $17 million per year.[1099]

[1096] Ex. SCE-06, Vol. 4, p. 88.

[1097] *Id.,* p. 86.

[1098] *Id.*, p. 93.

[1099] Ex. TURN-18, p. 1, citing Response to TURN DR 37, Question 9(b) (included in Ex. TURN-18-Atch, p. 16).

The historical funding method is not one the Commission can rely upon indefinitely. SCE closed its pension plan to new participants after December 31, 2017.[1100] This changes the underlying math, as the number of working employees eligible to participate in the plan and the pension-eligible payroll will shrink over time until each eventually reaches zero.[1101] But the amount of pension-eligible payroll is projected to be $1.1 billion in the 2025 test year, and $977 million in 2028, the last year of this rate case cycle, and SCE estimates the pension-eligible payroll will not reach zero for another 45 years, or 2068.[1102]

SCE's "new funding policy" is intended to "fix the mechanical issue with the current policy," and the utility contends it will achieve better alignment of contributions with benefit accruals and limit restrictions or costs associated with being underfunded.[1103] It comes with a higher direct cost: The "new funding policy" includes an "actuarial forecast" of $44.9 million for each year of the 2025 GRC period.[1104] In addition, SCE's proposal would reduce and perhaps eliminate the pension cost adjustments that have occurred through the operation of the Pensions Cost Balancing Account (PCBA) in recent years. Instead of using above-expected asset returns to provide near-term credits to ratepayers, under the new funding policy would be "accumulated" and addressed in the test year 2029 GRC period.[1105]

[1100] Ex. SCE-06, Vol. 4, p. 81.

[1101] *Id.*, p. 82.

[1102] Ex. TURN-114 Response to TURN DR 37, Question 5.

[1103] Ex. SCE-06, Vol. 4, p. 91.

[1104] *Id.*, p. 95.

[1105] Ex. SCE-17, Vol. 3, p. 58; Ex. TURN-111, p. 1 (Response to TURN DR 127, Question 3.a.). The credit that flowed through the PCBA due to 2021 recorded amounts was $59.4 million; the credit for 2022 recorded amounts was $84.9 million. Ex. TURN-113 (Excerpts of SCE ERRA testimony), pp. 9 and 24. Investment returns are a very significant part of the "non-service" costs that resulted in the 2021 and 2022 credit amounts. Patel, SCE, 1244, l. 16 to 1245, l. 8.

TURN urges the Commission to retain the historical funding policy for the test year 2025 GRC period, and defer adoption of any new policy until the test year 2029 GRC. SCE's approach would have its customers pay approximately $110 million of higher revenue requirement during the 2025 GRC cycle in order to mitigate risks that are neither as time-sensitive nor as dire as the utility makes them out to be. According to the calculations SCE presented from its actuary, the additional funding would serve to avoid having the plan underfunded by approximately 1%, and then only in 2028, the fourth year of the GRC cycle.[1106] TURN explains below why that 1% underfunded figure is overstated, given 2023 recorded returns. But even if it were a reasonable forecast, the Commission should still conclude that, on balance, having SCE's customers pay approximately $110 million less during this GRC cycle is the more reasonable outcome.

30.2.5.1 The Commission Should Adopt a Forecast of $17 Million for Pension Costs Based on the Historical Policy, Rather than the $44.9 Million SCE Proposes Under its New Funding Policy.

SCE forecasts $44.9 million for its Pension Plan costs for each of the four years in the 2025 test year GRC period.[1107] This forecast is premised on the Commission adopting SCE's "new funding policy." If the Commission were instead to retain the "historical funding policy" for this GRC period, the forecast would be $17 million, per SCE's calculations.[1108] TURN

[1106] Ex. TURN-18, p. 11.

[1107] Ex. SCE-06, Vol. 4, p. 81.

[1108] SCE's direct testimony did not include the GRC forecast figure that would result were the historical funding policy maintained for the test year 2025 GRC period. TURN obtained that figure through discovery - $17 million. Ex. TURN-18, p. 1, citing Response to TURN DR 37, Question 9(b) (included in Ex. TURN-18-Atch, p. 16).

recommends adoption of the $17 million figure derived by continuing the longstanding historical policy, rather than the $44.9 million figure SCE seeks under its new funding policy.

30.2.5.2 The Changed Conditions Associated with SCE's Pension Plan Being Closed to New Employees Do Not Require An Immediate Fundamental Change of Funding Policy With a $110 Million Price Tag.

SCE describes its proposed new funding policy as intending "to fix structural issues with the legacy funding policy arising from the Pension Plan having closed to new employees after December 31, 2017."[1109] TURN agrees that, with the closing of the plan to new participants, pension-eligible payroll will reduce over time. However, as noted above, there is no immediate urgency to revising the current policy. The actual recorded decline in eligible payroll is approximately 3.6% over the entirety of the 2018-2023 period.[1110] SCE projects a steeper pace of decline over the 2024-2028 period, but the remaining pension-eligible payroll would still be nearly $1 billion in 2028, the last year of the test year 2025 GRC period.[1111] Thus, while TURN does not dispute the need to modify the plan at some point in the foreseeable future, there is not such urgency that the plan must be modified at this time, rather than, for example, in the next SCE GRC.

Additionally, one of the issues SCE has identified as a basis for switching to its new funding policy is the possibility of an "unfunded liability" amount that would need to be

[1109] Ex. SCE-06, Vol. 4, p. 81.

[1110] The pension-eligible payroll was $1.315 billion in 2018 (the first year after the plan was closed to new employees), and $1.268 billion in 2023, a decline of approximately 3.6% over the five-year period. Ex. TURN-114 (Response to TURN DR 37, Question 5).

[1111] *Id.*

amortized over a continually decreasing time period.[1112] One of the touted features of the new funding policy is its element specific to recovering any "pension deficits" over an eight-year period tied to SCE's GRCs.[1113] But there is at present no such deficit, so under SCE's proposal this feature will not be deployed during the 2025 GRC period.[1114] Thus, waiting until the 2028 GRC to switch to a new policy would not reduce the amount of time available to amortize any "unfunded liability," should one arise during the 2025 GRC period.[1115]

The Commission should find that SCE has not presented evidence that action must be taken as of the start of the 2025 test year, rather than as of the start of the next ensuing GRC, for example.

30.2.5.3 SCE's Attempts to Establish Potential Near-Term Funding Shortfalls Under Continuation of the Historical Policy are Unpersuasive.

The Commission should find that SCE's attempts to illustrate potential funding shortfalls during the 2025 GRC period from retention of the historical policy were overstated and unpersuasive.

First, there is Figure III-17 as presented in SCE's direct testimony. The graph purports to illustrate that continuation of the historical funding policy risks an outcome where the "projected funded position" would be at or above 100% in all but the last year of the test year 2025 GRC

[1112] Ex. SCE-06, Vol. 4, p. 90.

[1113] *Id.*, p. 92.

[1114] *Id.*, p. 92. SCE states that there is no projected shortfall as of January 1, 2025, and "therefore the pension deficit amount included in the funding policy contribution is currently $0."

[1115] As explained more fully below, TURN submits that the Commission should find that it is unlikely that such an unfunded liability will arise during the 2025 GRC period.

period, when it would be at 99%.[1116] Nowhere does SCE explain why the Commission should find attaining a 100% funded level for three of four years, and a one-year period at 99% funded, to be such a problematic outcome that it warrants adopting a revenue requirement that is higher by approximately $28 million per year (or a cumulative $110 million over the four-year GRC period) in order to avoid it. The more reasonable conclusion the Commission should draw from Figure III-17 as presented by SCE is that the utility's Pension Plan would be adequately well-funded during the 2025-2028 GRC period even if the Commission retains the historical funding policy as recommended by TURN.[1117]

Then there is SCE's Figure III-17 as modified in TURN's direct testimony. The calculations leading to the percentages graphed by SCE include a forecasted "investment return" figure that ranges between approximately $195 million to $217 million per year for the historical funding policy, and $201 million to $217 million for the new funding policy.[1118] But in 2023, the actual investment return recorded by SCE was $349 million, rather than the $217 million SCE had forecasted for that year. If the 1/1/24 data point in SCE's Figure III-17 were updated to reflect the recorded amount reported in the utility's 10-K report filed with the Securities Exchange Commission (SEC) in early 2024, the "% Funded" figure under the historical policy increases from approximately 102.5% to 104%.[1119] As TURN's testimony illustrated with its

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[1116] Ex. SCE-06, Vol. 4, p. 97, Figure III-17.

[1117] Ex. TURN-18, p. 7. SCE's illustrative graph also establishes that the plan would be somewhat **over**-funded throughout that period under SCE's proposed new funding policy. The "New Policy" data points are slightly above 101% in each year from 2025 through 2028. Ex. SCE-06, Vol. 4, p. 97, Figure III-17.

[1118] Ex. TURN-112, pp. 3 and 4, line A.5. This "investment return" figure is different than and distinct from the "excess investment return" figure SCE used to derive its revenue requirement forecast of $44.9 million. Ex. SCE-06, Vol. 4, p. 93.

[1119] Ex. TURN-18, p. 8.

revised version of Figure III-17, adding the modified "% Funded" point based on the 2023 recorded data strongly suggests a substantially reduced likelihood of the plan being underfunded during the 2025-2028 period even with retention of the historical funding policy.[1120]

Exhibit TURN-112 puts a finer point to it. TURN had asked SCE to provide a recalculated Figure III-17 that made a single change -- substituting the recorded 1/1/24 figure for the forecasted figure SCE had included in the table version that appeared in its direct testimony. The utility had declined to do so, asserting that it "is not obligated to conduct new studies or analyses in response to data requests."[1121] Therefore TURN used the Excel version of the SCE version of the calculations behind the utility's graph to prepare the modified version of the calculations, the task the utility refused to perform.

TURN's cross-examination of SCE's witness reviewed in some detail the calculations underlying Figure III-17 as it appeared in SCE's testimony.[1122] The cross-examination also established that TURN's two additional tables had revised a single input figure for SCE's

[1120] *Id.*

[1121] Ex. TURN-112, p. 2 (Response to TURN DR 127, Question 1.b.). SCE's refusal to perform such a calculation in a GRC is a relatively recent development. The test year 2018 GRC decision describes the utility making a "single change to it regression model" in order to enable a comparison of "SCE's forecast with TURN's modification to that forecast." D.19-05-020, p. 274. As TURN demonstrated during the evidentiary hearing, the calculations underlying Figure III-17 were far more straightforward than a regression model.

[1122] TURN first established that the "Investment Return" figures included in SCE's calculations reflected an assumed return of 6.5% in every year. Patel, SCE, 12 RT 1223, l. 23 to 1224, l. 17. TURN then methodically reviewed with the witness each of the categories of costs or credits included in the utility's calculation of the "Fair Value of Assets" and the Projected Benefit Obligation (PBO), and the use of the total from each of those two categories to derive the "Funded Status" as a percentage. *Id.*, at 12 RT 1225, l. 21 to 1229, l. 8. TURN then discussed how the outcomes from 2023 influenced the calculations for 2024. *Id.*, at 12 RT 1229, l. 9 to 1230, l. 12. TURN also confirmed with SCE's witness that 1) the figures for 2023 and 2024 in the two tables as prepared by SCE were identical, as were the amounts for "Benefit payments" and "Administrative expenses from trust" for the years 2025 through 2028, but 2) starting in 2025 the higher amounts collected in rates under the New Funding Policy would increase the "Employer contributions" figure and the "Investment return" figure (as the 6.5% assumed return was applied to a slightly higher balance due to the higher Employer contributions). *Id.*, 1231, l. 4 to 1234, l. 7.

calculations (the Investment return figure for 2023), and held the other input figures constant.[1123] In TURN's version, the Fair Value of Assets figures for the end of 2023 and for each year thereafter increased, the mathematical result of reflecting the higher investment return for 2023, as did the "Funded Status" for each year.[1124] And where SCE's Figure III-17 had shown a Funded Status of 99% in 2028, the same calculation with the same assumptions other than replacing SCE's 2023 "Investment return" figure with the recorded 2023 investment return produces a "Funded Status" of 103% in 2028.[1125]

SCE's re-direct examination of the utility's pension witness seemed to suggest it viewed TURN's illustration as putting the Commission at risk of drawing undue conclusions off of a single year's asset return performance, or structuring the pension funding policy based on a single year's returns.[1126] But TURN is not proposing to change the amount of returns, either on a percentage or a dollar basis, for 2024 to 2028 – TURN's calculations used the same return figures for those years as did SCE. Furthermore, SCE pointed to its testimony's table of the pension fund's recorded return rates for the period from 2008 through 2022 for the proposition that market returns were very volatile during that period.[1127] TURN submits that the historical data better serve to indicate that the return estimate that SCE uses in its calculations is relatively conservative, as the reported returns exceeded 6.5% in ten of the fifteen reported years.[1128] In

[1123] Ex. TURN-112, p. 5; Patel, SCE, 12 RT 1235, ll. 2-21; 1236, l. 23 to 1237, l. 19; and 1238, ll. 8-13.

[1124] Ex. TURN-112, p. 3 (SCE-prepared table for "Historical Funding Policy"), lines A.1, A.6, and C.1; compare to p. 5 (TURN-prepared table for "Historical Funding Policy"), lines A.1, A.6, and C.1.

[1125] Ex. TURN-112, p. 5, line C.1.

[1126] Patel, SCE, 12 RT 1268, l. 9 to 1269, l. 24.

[1127] Patel, SCE, 12 RT 1269, ll. 3-14, referring to Ex. SCE-06, Vol. 04, p. 85, Table III-10.

[1128] Ex. SCE-06, Vol. 04, p. 85, Table III-10. If one were to look at the recorded return figures from 2004-2007 as well, the 6.5% estimate here was exceeded in fourteen of the nineteen years in the 2004-2022 period. Ex. TURN-116 (SCE TY 2021 GRC Testimony), p. 78, Table III-10. And given the much addition, SCE cannot be permitted to elevate its assumptions for the 2023-2028 period to a sacrosanct status, such that the funding status estimates it developed based entirely on those assumptions are treated as inherently more reliable than near-identical funding status estimates that rely on the same assumptions, save a single recorded year's amount for the return. If SCE's model is so fragile that it goes from reliable to unreliable with the change of a single input from an estimated figure to a recorded figure, the problem is not with TURN's proposed change, but with the model itself.

To be clear, TURN's recalculation of the "projected pension funding status" that SCE included in Figure III-17 of its testimony is <u>not</u> intended to suggest that the Commission should assume that investment returns in 2024-2028 will be at a level higher than 6.5% for any year other than 2023, as reflected in the reported 1/1/24 figure for 2023. Rather, TURN asks the Commission to treat the results of the recalculation presented in Ex. TURN 112 as further confirmation of why it should reject SCE's undue urgency for a new policy: Adoption of a GRC funding level of $17 million consistent with the historical funding policy will likely lead to a funding status of greater than 100%, rather than the 99% figure that SCE calculated.[1129]

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higher investment return recorded in 2023 as compared to SCE's forecast, the Commission can reasonably infer that the 6.5 % figure was exceeded that year as well.

[1129] Ex. TURN-18, p. 9.

30.2.5.4 SCE's New Funding Policy Would Postpone Credits from Higher than Forecasted Market Returns to the 2029 GRC Period, Rather than Permitting those Credits to Provide Some Amount of Near-Term Rate Relief.

Investment returns and the amount SCE collects in rates for its pension expenses "are the Pension Plan's only funding sources."[1130] SCE's testimony described the circumstance where investment returns are lower than expected, requiring additional "contributions" collected from ratepayers.[1131] But over the last fifteen years, the pension fund performance has "compared favorably to market benchmarks," despite weak market performance in four of those fifteen years. And during the 2021-2024 GRC period (a period containing one of the four weak market years), SCE expects to see the actual contributions collected from ratepayers under the historical funding policy be less than the authorized amount due to the "stronger longer-term market performance."[1132]

Under the historical funding policy, SCE ratepayers see their actual contributions reduced during periods of relatively strong market performance, with at least part of that reduction achieved through the annual adjustment made in the Pensions Cost Balancing Account (PCBA). To the extent returns earned by pension trust assets in a given year exceeded expected amounts, some but not all of that excess return is credited to ratepayers.[1133] These excess return amounts constitute a "significant" portion of the "non-service costs" tracked in the PCBA,[1134] and

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[1130] Ex. SCE-06, Vol. 4, p. 86.

[1131] *Id.*

[1132] *Id.*

[1133] Ex. TURN-111 (Responses to TURN DR 127), p. 1 (Response to TURN DR 127-3b); Patel, SCE, 12 RT 1248, ll. 1-7.

[1134] Patel, SCE, 12 RT 1244, l. 16 to 1245, l. 8.

contributed to substantial credits benefiting ratepayers in recent years. In 2021, the "net gain" from the "non-service costs" was $87.6 million, and was the main factor contributing to an overcollection of $59.4 million that was credited to SCE's ratepayers at the start of 2022.[1135] In 2022, the net gain amount was $107.1 million, and the overcollection credited at the start of 2023 was $84.9 million.[1136] Thus, under the historical funding policy, the above-anticipated returns recorded during the 2021 GRC period serve to reduce the amounts collected in rates during that same GRC period, with at least some of that reduction occurring through the PCBA.

SCE's "new funding policy" would fundamentally change this element of current ratemaking. The amount of higher investment returns to be reflected in rates in each year of the 2025 GRC period would be capped for the entirety of the period at an amount SCE seems to have selected based on its comfort level.[1137] Should the actual returns exceed that set amount, the excess returns would no longer be credited back to ratepayers during the 2025 GRC period, but instead "would be accumulated and increase the 'excess investment return' credit starting with the next [test year, here 2029]."[1138] Thus, amounts that under the historical policy would have been available at least in part to be credited to SCE ratepayers during the test year 2025 GRC cycle would, under the proposed new funding policy, <u>not</u> be credited during this cycle and instead would be "accumulated" until at least 2029.

[1135] Ex. TURN-113, pp. 9-10 (SCE 2022 ERRA testimony excerpt, pp. 63-64).

[1136] *Id.*, pp. 24-25 (SCE 2023 ERRA testimony excerpt, pp. 68-69).

[1137] Ex. SCE-06, Vol. 4, p. 93. SCE would set the "amount of excess investment return expected" at $36 million. As noted earlier, in 2023, the amount of excess investment return recorded was $132 million. Ex. TURN-18, p. 9.

[1138] Ex. SCE-17, Vol. 3, p. 58; Patel, SCE, 12 RT 1246, ll. 3-9.

TURN submits SCE did not sufficiently emphasize this aspect of its "new funding policy." The utility's direct testimony referenced the new policy's treatment of a Projected Benefit Obligation (PBO) shortfall in several places.[1139] There was no similarly direct reference to how investment returns that exceed expected levels would be treated differently as compared to under the historical policy. Instead, SCE repeatedly stated that it was seeking "continuation of the existing [PCBA],"[1140] with "no change to the clear and well-defined operation of the pension balancing account or its application to ERRA as approved in [GRCs since 2006]."[1141] It may be technically true that the PCBA will not change, in that the key provisions of its tariff language may remain the same. But SCE's rebuttal testimony, discovery on that rebuttal testimony, and cross-examination of SCE's witness made clear that the PCBA will not operate in the same way under the new funding policy because the returns in excess of the annual forecast amounts would no longer flow through it to provide near-term rate relief to SCE's customers.[1142]

30.2.5.5 The Commission Should Consider Adopting the "Annual Check-up" Process SCE Proposed in its 2021 GRC.

Even though SCE has failed to present a compelling showing in favor of adopting its proposed "new funding policy" rather than maintaining the "historical funding policy" for the 2025 GRC cycle, TURN recognizes that circumstances can change, even over a four-year GRC period. In its 2021 GRC testimony, SCE proposed an annual review of the current funding

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[1139] Ex. SCE-06, Vol. 04, pp. 81, and 91-92.

[1140] *Id.*, p.

[1141] Ex. SCE-17, Vol. 3, p. 59.

[1142] *Id.*, p. 58, Ex. TURN-111, p. 1 (Response to TURN-127, Question 3.a.); Patel, SCE, 12 RT 1247, ll. 4-17.

policy to enable the possibility of updating that policy if shown to be necessary before the next GRC cycle.[1143] To be clear, TURN does not believe SCE has established that any such update is required at this time, or likely to be warranted during the 2025 GRC cycle. However, if the Commission wishes to create an informal process to check that changed circumstances do not warrant a different approach on relatively short notice, it could direct SCE to work with other interested parties to develop and propose such an informal process.

30.2.6 Post-Retirement Benefits Other than Pensions (PBOPs)

For test year 2025, SCE forecasts $0.0 million for its Post-Retirement Benefits Other than Pensions (PBOP) costs.[1144] This is in large part due to the fact that the PBOP trust fund assets had reached $2.21 billion as of the end of 2022, and are invested such that the ongoing returns contribute to covering the PBOP costs.[1145] As reported in SCE's ERRA testimony, the figure at the end of 2022 meant the entire PBOP plan was overfunded by approximately $885 million.[1146] As of the end of 2023, the overfunded amount had grown to $1.5 billion.[1147]

TURN supports adopting a funding level of $0 for the test year 2025 GRC period, as making sure overfunded amount does not continue to grow in part due to amounts collected from ratepayers is an important first step.[1148] But TURN urges the Commission to recognize the degree of overfunding presents two areas warranting further inquiries: Is the overfunded amount sufficiently protected from being put to uses that are not in the interest of SCE's ratepayers? And

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1143 Ex. TURN-116 (SCE 2021 GRC Testimony), p. 84 (ll. 3-12).

1144 Ex. SCE-06, Vol. 04, p. 103.

1145 *Id.*, p. 109.

1146 Ex. TURN-113, p. 29 (SCE 2023 ERRA testimony excerpt, p. 73).

1147 Ex. TURN-18, pp. 2 and 17, citing SCE's 10-K filing for 2023.

1148 *Id.*, p. 2.

are there alternative uses for the overfunded amount that might be permitted and would serve to further the interest of SCE's ratepayers?

The record establishes that SCE has already begun the process of identifying opportunities to put the overfunded PBOP trust fund amount to other purposes. For example, in the ERRA testimony revealing the $885 million overfunded status as of the end of 2022, the utility stated, "SCE has been seeking ways to address this funding imbalance and believes that there will soon be a path forward for doing so."[1149] TURN's testimony raised the concern about opportunities for the company to sell or otherwise transfer the obligations and the fund in a manner that might shortchange SCE ratepayers, such that they ultimately receive a reduced or discounted value from the trust.[1150]

SCE asserted that the funds are "locked up" while in the trust, and subject to "very tight guidelines."[1151] But in a "Funding Policy Discussion" document provided in mid-2022 to SCE by its pension and PBOP actuary, the "PBOP Funding Policy" included references to the possibility of amending the trusts to cover "PAYGO" benefits that are "not covered by existing trusts." The document also includes the heading "No need for CPUC input (?)," followed by a note indicating that SCE, or at least its actuary, thought that such amendments of the trust may not "have GRC implications."[1152] The following page includes the statements, "$71 million of 'pay-as-you-go' benefits are not currently backed by any trust assets and associated benefit

[1149] Ex. TURN-113, p. 29 (SCE 2023 ERRA testimony excerpt, p. 73).

[1150] Ex. TURN-18, pp. 18-19.

[1151] Patel, SCE, 12 RT 1258, ll. 24-25.

[1152] Ex. TURN-115 ("SCE Funding Policy Discussion" dated July 13, 2022), p. 12.

payments of ~$10m annually are paid from corporate assets," and "Expectation is most pay-as-you-go obligations would be covered by 401(h) via plan amendment."[1153]

It may be that the use of trust assets to cover amounts not currently "backed" by those assets can be structured in such a way as to be entirely in ratepayers' interest. But the Commission has no way to know this based on the minimal information SCE has put forward to date on the subject. And the utility's internal document suggests changes could take place without any need for Commission review or approval. In order to ensure that any such discussion includes not only the utility's actuary but also its regulator, the Commission should direct SCE to, no later than its next GRC, present a showing regarding its efforts seeking ways to address the funding imbalance, and any "paths forward" it has identified for protecting ratepayers' interest in these funds.[1154] The Commission should further direct SCE to report on any use of trust assets to date to fund benefits that had not previously been backed by trust assets, and on the results of any further inquiries or investigation it has made into the "need for CPUC input" regarding such matters.

30.3 Employee Training

30.3.1 Training Seat Time and Delivery – Transmission and Distribution

TURN recommends that the Commission reduce SCE's test-year expense forecast of $60.222 million for Training Seat Time and Delivery – Transmission and Distribution (T&D) to a more reasonable forecast of $46.383 million. The utility's forecast is 62% higher than the base

[1153] *Id.*, p. 13.

[1154] Ex. TURN-18, p. 19.

year expense of $37.058 million[1155] and SCE has failed to demonstrate that the increase is just and reasonable.

The Training Seat Time and Delivery – T&D is divided into a (i) Training Seat Time forecast of $37.023 million, for which TURN's recommendation includes a reduced recommendation of $28.511 million; and (ii) Training Delivery forecast of $28.511 million, for which TURN's recommendation includes a reduced recommendation of $17.872 million.[1156]

As noted below, TURN's Training Seat Time recommendation includes, among other items, a reduction for TURN Witness Jones's observation that labor rates should be separated between new hires and existing employees rather than using a single, monolithic rate for all employees who attend a certain type of training.[1157] However, SCE's Rebuttal Testimony states,

> The itemized model by individual class and standard labor rate by job classification expected to attend those classes already accounts for the variance in labor rates by roles, as well as the new employee/existing employee dichotomy that TURN is attempting to address with its proposed forecasting model.[1158]

While no evidence of this assertion in SCE's rebuttal has been presented, TURN nevertheless allows for the possibility that SCE's model includes differential Seat Time charge rates that, if true, would account for TURN's recommendation to reduce the average training compensation rate to address the dichotomy of new vs. existing employee costs. As such, TURN introduces an alternative forecast for the Commission to consider, one that uses TURN's primary recommendation regarding Training Seat Time hours, but relies on SCE's forecast of rates.

[1155] Ex. TURN 14-E2, pp. 36-37.

[1156] Id., p. 38. *See also*, Ex. TURN-14 WP.

[1157] Id., p. 45.

[1158] Ex. SCE-17, Vol. 3, pp. 97-98.

TURN's alternative forecast is $29.204 million[1159] – rather than the $28.511 million that is suggested under TURN's primary recommendation, as identified above.

Regardless of the Commission's decision on whether the particular forecast is reasonable, the Commission should order SCE to, either manually or dynamically within the RO Model, reduce both the Training Delivery and Training Seat Time activities if the Commission makes reductions to any training-impacted personnel on a prorated, percentage basis, that starts with the 2025 test year forecasts that the Commission adopts, as recommended by TURN Witness Jones.[1160] The Training activities are mostly volume based – for example, the incremental costs within Training Delivery primarily owe to increased training demand, which in turn derives primarily from increased hiring in the field to support projects within the main organizational units of T&D – and the Training Seat Time is by definition volume based.[1161] The Commission's adoption of this recommendation would help ensure that any reductions to SCE's personnel counts that the Commission adopts will be reflected by the Training Seat Time- and Delivery-activity forecasts. This recommendation appears to be unrebutted by SCE.[1162]

[1159] Calculated in the same manner as TURN's original calculation in TURN's Workpaper, Ex. TURN-14 WP, tab "Del_SeatTime-NHExiSpt_TURNCalcs", but with the application of SCE's average compensation rate of $56.89 for all Training hours with the corresponding change to the Non-Labor Forecast, which is calculated by SCE as 17% of the Labor Forecast (according to WPSCE06V04BkC, p. 249, as: [the sum of TURN-recommended New Hires and Existing Employees training hours (358,000 hrs., per Ex. TURN-14-E2, p. 44) x the average rate according to SCE ($56.89/hr., per WPSCE06V04BkC, p. 249)] + [the sum of TURN-recommended New Hires and Existing Employees training hours (358k) x the ratio of SCE's Employee Compensation Benefits value ($688k/$26.892M, per WPSCE06V04BkC, p. 249)] + [the remaining Labor items ($4.327M, per Ex. TURN-14-E2, p. 47)] + [the Non-Labor Forecast ($3.518M, per TURN's updated Labor Forecast of $20.367M (i.e., 358,000 hrs. x $56.89/hr. x SCE's 17% Labor-to-Non-Labor ratio (from WPSCE06V04BkC, p. 249)] + [the remaining Non-Labor items ($3.888M, per Ex. TURN-14-E2, p. 47)].

[1160] Id., pp. 38-39.

[1161] Id.

[1162] Ex. SCE-17, Vol. 3, pp. 93-98 and 102-103.

30.3.1.1 T&D Training Seat Time

TURN's forecast for Training Seat Time is primarily based on the 2023 recorded unit count for new-hire (or new role)-related training and an average of the 2018-2019 recorded unit count, the ongoing training of existing employees.[1163] On this point, SCE's Rebuttal Testimony appears to misinterpret the basis of TURN's Seat Time forecast, claiming that TURN's forecast is "based on the 2023 Training Time hours planned against the recorded value."[1164] While true that TURN's forecast of the new-hire-related portion of the forecast is based on the 2023 recorded value, the ongoing existing employee-related portion is based on the average of the recorded 2018-2019 forecast.[1165]

Prior to accounting for the additional items of Safety Training Seat Time Labor, Employee Compensation Benefit (i.e., STIP-to-Base Pay conversion), and Organizational Training Labor, the combined effect of reducing training time and separately calculating the existing and new-hire labor rates yields a Labor cost of $19.789 million, compared to $26.892 million under SCE's forecast methodology. After accounting for the additional items, with the Employee Compensation Benefit component of the forecast adjusted for a lower Labor amount, TURN's total Labor forecast for Training Seat Time is $24.623 million. This is $7.285 million lower than SCE's forecast of $31.908 million.[1166]

[1163] Ex. TURN-14-E2, p. 44.

[1164] Ex. SCE-17, V03, p. 92.

[1165] Ex. TURN-14-E2, p. 45.

[1166] Id., pp. 46-47.

Other than two small items (Organizational Training Non-Labor and Employee-Led Efficiency Savings), SCE's Non-Labor forecast for the Training Seat Time activity is calculated as a percentage of the Labor forecast. Therefore, the adjustments that TURN.

The following table shows the high-level similarities and differences between SCE and TURN's proposals.

Table 12: Itemized Comparison of SCE and TURN's Training Seat Time Forecast (1,000s of Constant 2022$)1167

Category	SCE	TURN	SCE>TURN
Labor (New Hires and Existing) (473k hours x Labor Rate = $56.89)	26,892	N/A	N/A
Labor (New Hires) (310k hours x Labor Rate = 46.73/hr)	N/A	14,475	N/A
Labor (Existing) (48k Labor Rate = $110/hr)	N/A	5,314	N/A
Labor (TOTAL)	26,892	19,789	7,103
Employee Compensation Benefits	688	507	182
Remaining Labor Items	4,327	4,327	-
LABOR SUBTOTAL	31,908	24,623	7,285
Non-Labor	4,645	3,418	1,227
Remaining Non-Labor Items	470	470	-
NON-LABOR SUBTOTAL	5,115	3,888	1,227
TOTAL	37,023	28,511	8,512

However, if the Commission were to agree with SCE regarding the labor rate used in the Training Seat Time forecast, TURN's alternative forecast is $29.204 million – rather than the $28.511 million that is suggested under TURN's primary recommendation, as noted above.

30.3.1.1.1 The Basis of TURN's Forecast is Reasonable

SCE claims two sources of seat-time demand: demand for the training of new hires (or the transition by existing employees to new roles) and ongoing training of employees in incumbent roles.[1168] TURN's recommendation provides SCE with a reasonable forecast of

[1167] Ex. TURN-14-E2, p. 47.

[1168] Id., p. 43, referencing SCE Response to DRs TURN-SCE-008-3.a, -7.a, and -9.a (included in Exhibit TURN-14-Atch1).

Training Seat Time hours, which contains the number of new-hire-related Seat Time hours that were *recorded* in 2023, the year that SCE claims is a reasonable proxy of 2025.[1169] This will allow SCE to address the main drivers of the hiring-generated training needs and the incremental Training Seat Time labor forecast, such as Safety and Reliability Investment Incentive Mechanism (SRIIM) and Service Planning organization.[1170,1171]

Regarding the ongoing training of existing employees, TURN removes the effects of the COVID rebound by recommending that the Commission adopt the two-year, 2018-2019 average of pre-pandemic, recorded Seat Time hours related to the on-going training of existing employees, given that the COVID rebound will clearly be in the rear-view mirror by 2025.[1172] Not only are these measures reasonable, but they are designed to conservatively reduce SCE's forecast of an activity that the company almost always over-forecasts and serve as a counterweight to a forecast that SCE has rendered impossible to test or audit.[1173]

30.3.1.1.2 SCE's Showing Regarding the Training Seat Time Hours Forecast is Problematic

SCE based its 2025 Training Seat Time forecast on the number of *planned* 2023 units because it expects 2025 to have similar training demand across the two years.[1174] SCE's Rebuttal Testimony emphasizes the reasonableness of the company's total 2025 Seat Time-hours

[1169] Ex. TURN-14-Atch1, SCE Response to DR TURN-SCE-008-03.h.

[1170] Ex. SCE-06, V04, pp. 183-185.

[1171] Ex. TURN-14-E2, pp. 44-45.

[1172] Id., p. 41.

[1173] Id., pp. 41-42.

[1174] Ex. TURN-14-Atch1, SCE Response to DR TURN-SCE-008-03.h.

forecast on the basis that the 2023 *recorded* hours are significantly higher than previous, historical years.[1175] However, a more appropriate starting point for establishing the reasonableness of the company's 2025 forecast is to compare the 2023 seat-time hours plan against the recorded hours.[1176] The utility planned for 471,000 total Seat Time hours in 2023, but recorded just 391,000 which is 83% of planned.[1177] Moreover, SCE has historically recorded much less training than planned – the recorded training hours for the historical period (save for the COVID-affected 2020) average 80% of planned with the pre-pandemic, with the recorded 2019 value, at 67% of planned, being substantially lower.[1178]

Such facts cast doubt on SCE's 2025 forecast and the Commission could reasonably assume that the 2025 recorded value will fall short of the forecast. In the face of such facts, however SCE would now have the Commission approve a forecast that is based on a Seat Time-hours forecast that is about 80% *higher* than the average in the non-COVID period of 2018-2019 and 2021-2022.[1179] Contrary to what SCE attempts to portray in its Rebuttal Testimony[1180], while TURN's Training Seat-hour forecast is not as extravagant as SCE's, it *is* conservatively higher than the relevant historical period suggests is necessary – i.e., TURN's forecast of 358,000 compared to an average of 263,000 in non-pandemic, historical years (i.e., 2018-2019 and 2021-2022), and also compared to 290,000 in 2022.[1181]

[1175] Id., p. 94.

[1176] Ex. TURN-14-E2, p. 43.

[1177] Id., pp. 43-44.

[1178] Ex. TURN-14-E2, p. 45, Table 13.

[1179] Id.

[1180] Ex. SCE-17, Vol. 3, pp. 96-97.

[1181] Ex. TURN 14-E2, p.43.

SCE's Direct Testimony identified the COVID rebound as the explicit and sole reason for the increase to training costs, stating, "As the impacts of COVID-19 continue to decline, it is expected that training volume will continue to increase as a result of increased hiring, returning to normal training levels and/or continued make-up from prior deferrals."[1182] TURN does not object to an increase to incremental training hours from "increased hiring" relative to the base year, but simply recommends that the 2025 forecast be based on the 2023, *recorded* unit count (rather than the planned count), given SCE's contention that 2023 unit-count levels would be the same as 2025 levels. The recorded, 2023 level would allow SCE to address the increased hires for SRIIM and such organizations as Service Planning, as well as the company's request for funding for the multi-year impacts for programs in extended and/or multi-year duration, such as the three-year Apprenticeship programs,[1183] given that SCE contends that the demand in 2023 and 2025 will be the same.[1184]

SCE's argument in Rebuttal Testimony that, in using the 2023 *recorded* values as the basis for the 2025 Seat Time-hours forecast rather than the 2023 *planned* values, TURN failed to realize that the 2023 recorded value was not available when the utility's initial testimony was developed,[1185] is a curious argument. Why should the Commission not rely on a recorded value, regardless of whether it was known at the time of the utility's forecast development, as a way to evaluate the reasonableness of SCE's forecast? SCE explicitly tied the activity level in *2025* to

[1182] Ex. SCE-06, Vol. 4, p. 179.

[1183] Id., p. 172.

[1184] Id., p. 181.

[1185] Ex. SCE-17, Vol. 3, p. 96.

that in *2023,* and offered no other rebuttal against the use of 2023 recorded values to forecast the new-hire-related portion of the Seat Time count.[1186]

As for the forecasted increase to base-year spending as the result of "returning to normal levels", this is exactly what TURN's forecast is consistent with. TURN's forecast for the ongoing training of existing employees is based on the average of 2018-2019 recorded values. The pre-pandemic level, not a level indicated by COVID-19 recovery, would be the "normal" level for ongoing training for existing employees.

As for the forecasted increase to base-year spending as the result of "continued make-up from prior deferrals", the claim is already tenuous enough when contemplating a 2025 test year – some four to five years on from the height of the pandemic – and impossible to verify with the dearth of information forthcoming from the company, as explained by TURN Witness Jones.[1187] Despite the use of what SCE dubs a "bottoms-up itemized forecast methodology" for forecasting both Seat Time and Delivery, the utility was unable to produce a model that was anything other than a tautological absurdity comprising hardcoded Training Seat Time hours with no detail regarding the development of the underlying Seat Time durations and occurrences, as identified by TURN Witness Jones[1188] and admitted to by SCE in rebuttal.[1189] This is despite TURN's repeated attempts to obtain such simple information as the identification of the training hours,[1190] how many training sessions were cancelled and/or deferred, how many remain unexecuted, or

[1186] Id., pp. 93-98.

[1187] Ex. TURN-14-E2, p. 41.

[1188] Id., pp. 40-41.

[1189] Ex. SCE-17, Vol. 3, pp. 93-94.

[1190] Ex. TURN-14-E2, pp. 40-41 and Ex. TURN-14-Atch1 (Attachment 3 and SCE Responses to DR TURN-SCE-008-04.a, DR TURN-SCE-008-04.a Supplemental Answer and corresponding attachment, TURN-SCE-008-04.a.Supplemental).

how many cancelled and deferred sessions will be executed in 2023 and beyond.[1191] Without such information, the values remain hardcoded with no derivation, justification, or explanation as to their provenance. This leaves the "bottoms-up model" as a simply untestable proposition, a "give us the number of hours that we say we need because that is the number of hours that we say we need."

SCE attempted to justify the hardcoded values in the so-called, bottoms-up model and the general lack of support for its request in its Rebuttal Testimony, stating, "The quantity of Training Seat Time occurrences is derived through subject matter expertise, standard baseline class sizes where applicable, and conversations with organizational leadership to align training plans with expectations."[1192] While perhaps true, the cloak of "subject matter expertise", "conversations with leadership", and the like, provides no way of testing the hardcoded values, as proved by TURN's repeated attempts to obtain elementary information that could reasonably be used to test SCE's forecast.[1193] Further, SCE has not established that these factors that it derives its forecast from are any better, or even different, than those that informed its significant over-forecasts in prior years.

Moreover, SCE's Rebuttal Testimony then alleged that there are "multiple dynamic, complex, and influencing factors that impact training volume beyond the scope of training operations," and attempted to rehabilitate the company's showing by highlighting "pandemic[-related]…factors outside of training [that] may have had a downstream effect to training with

[1191] Ex. TURN-14-E2, p. 42, supported by Ex. TURN-14-Atch1 (SCE Response to DR TURN-SCE-008-03).

[1192] Ex. SCE-17, Vol. 3, pp. 93-94.

[1193] TURN-14-E2, pp. 40-41.

longer-term impacts."[1194] However, the company provided no concrete examples for such effects, no way to test the assertion, and no reason to believe that such effects might last until 2025, 4-5 years after the height of the pandemic.[1195] SCE further alleged in its Rebuttal Testimony, while remaining silent in its Direct Testimony, "[F]actors unrelated to the pandemic also influence training demand…, [although] SCE does not track specific, increase or decrease for each unique and specific driver, especially in the case of an unprecedented global pandemic."[1196] This last point is undermines SCE's position. First, the company pinned the increase in expected Seat Time hours entirely to the pandemic in its Direct Testimony, and then reversed its position in Rebuttal by stating that there are other, non-pandemic drivers at play, drivers that not only does the company not track, but that are apt to vary from year to year even from a historical perspective.[1197] If the company does not track such activities and those activities are given to vary from year to year, how would the company know that the demand for such activities would increase and how is the Commission supposed to audit the reasonableness of the allegation?

Finally, SCE claims in Rebuttal Testimony, "Not being authorized sufficient funds for 2025 and beyond would require SCE to reduce training hours."[1198] The Commission should not succumb to such a strawman argument. TURN's recommendation allows SCE sufficient funds

[1194] Ex. SCE-17, Vol. 3, p. 94.

[1195] Id.

[1196] Id., p. 94.

[1197] Ex. SCE-17, Vol. 3, p. 95.

[1198] Id., p. 96.

to do the training that it will need to do in the future and does not constitute a mandate for training reduction.

30.3.1.2 T&D Training Delivery

SCE's Training Delivery labor forecast consists of adjunct, internal SCE employees from other organizations to facilitate training, in addition to T&D Training staff and personnel, including permanent instructors, back-office support, analytical support, administrative support, and leadership.[1199] TURN recommends a T&D Training Delivery Labor forecast (excluding the newly formed Safety Training) of $12.422 million, which is $3.980 million less than SCE's forecast of $16.402 million,[1200] which is a 24.3% reduction.[1201] TURN, likewise, reduces the quantity input for the Non Labor calculator by 24.3%, given that estimated rates and quantities of Non Labor expense anticipated to be needed to accommodate delivery to the forecasted Seat Time training hours are used to forecast Non-Labor expenses.[1202] This reduction simply comports with the way SCE calculates Non Labor, but accounts for the lower Labor forecast that TURN recommends. Finally, TURN adjusts the Employee Compensation Benefits component of the forecast in similar fashion to the way that it adjusts for the Training Seat Time.[1203,1204]

TURN's recommendation for the Labor forecast is supported by SCE's Direct Testimony, which indicated that the "Training Delivery … and Training Seat Time [are] based

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[1199] Ex. SCE-06, Vol. 4, p. 182.

[1200] Ex. TURN-14-E2, p. 49.

[1201] Ex. TURN-14-E2, p. 48.

[1202] Id.

[1203] Id.

[1204] See Ex. TURN-14-E2, p. 49, Table 16 for an itemized comparison of SCE and TURN's Training Delivery Forecast, which includes Labor and Non-Labor components.

on “the volume of expected training hours to be delivered and standard labor rates averaged by class type for…staff and personnel associated with delivering and operating training programs.”[1205] It is, therefore, reasonable to reduce the quantity input to the Labor-forecast calculation by the percentage of any reductions to the seat time quantity made in the Training Seat Time Labor calculation.

SCE claims to use a bottoms-up analysis that is based on the volume of expected training hours to be delivered and standard labor rates averaged by class type for the employee job classifications planned to attend training and/or staff and personnel associated with delivering and operating training programs, as previously noted. TURN has not received an analysis that shows how the Labor hours for Training Delivery are derived, despite repeated attempts, as documented above in the Seat Time section above.

SCE contended in Rebuttal Testimony that TURN’s approach should not be relied upon because, “while some Training Delivery forecasting is dependent on increased training volumes, it is not a one-to-one relationship, [and] specific delivery expenses are not being forecasted in an itemized manner meaning that some items will be greatly over forecasted while others are greatly underforecasted.” SCE further alleges that TURN’s approach is flawed because (1) Training Seat Time and Training Delivery are different activities with different cost drivers and assumptions; (2) the blanket-percentage reduction that TURN applies ignores the standard labor rates of the employees charging to the activity; and (3) TURN’s model ignores the possibility that non-labor expenses, quantities, and associated cost assumptions can be different than they are for labor and may or may not be dependent up on Training Seat Time – T&D volume.[1206]

[1205] Ex. SCE-06, Vol. 4, pp. 180-181.

[1206] Ex. SCE-17, Vol. 3, p. 102.

TURN submits that SCE has failed to meet its burden to establish the reasonableness of its forecast when the only workpapers it provided are full of hardcoded inputs with little to no information about the provenance of the inputs. SCE's approach severely limits the Commission's ability to audit a so-called, bottoms-up forecast. While there might not be a one-for-one relationship between Training Delivery costs and Training volume, it is the best and most transparent evidence that any party has produced in this proceeding. It is SCE, after all, that suggested, "…Training Delivery… [is] based on the volume of expected training hours to be delivered and standard labor rates averaged by class type for the employee job classifications planned to attend training and/or staff and personnel associated with delivering and operating training programs."[1207]

Finally, based on its objection to TURN's testimony regarding the Labor forecast for Training Delivery, SCE objects to TURN's reduction to the Non-Labor and Employee Compensation Benefits-adjustment forecast.[1208] Given that TURN continues to recommend the Labor reduction, its Non-Labor forecast and adjustment to the increase for Employee Compensation Benefits are reasonable and should be adopted.

[1207] Ex. SCE-06, Vol. 4, pp. 180-181.

[1208] Ex. SCE-17, Vol. 3, p. 102.

31. TOTAL COMPENSATION STUDY

32. ENVIRONMENTAL SERVICES

32.1 Environmental Services O&M

SCE's forecast for Environmental Services O&M includes two components, (1) Environmental Management and Development, and (2) Environmental Programs.[1209] TURN addressed SCE's forecast for Environmental Programs in its testimony.[1210]

SCE originally forecast $22.694 million for Environmental Programs, including $1.335 million in labor and $21.359 million in non-labor.[1211] SCE subsequently modified its labor forecast to $1.329 million, bringing its total forecast to $22.689 million.[1212] TURN took issue with SCE's request for an $8.07 million increase in non-labor. TURN pointed to SCE's failure to support this requested increase and also the consistent decline in non-labor costs in every year from 2018-2022.[1213] TURN recommended a forecast of last recorded year, consistent with the Commission's guidance in prior GRC decisions that last recorded year is appropriate to use as a forecast when costs trend in one direction over three or more years.[1214] TURN recommended a forecast of $14.845 million, including $1.553 in labor and $13.292 million in non-labor.[1215] Cal

[1209] Ex. SCE-06V06, p. 5.

[1210] Ex. TURN-11 (Defever), pp. 4-6.

[1211] Ex. SCE-06V06, p. 20.

[1212] Ex. SCE-06V06E5, p. 20E5.

[1213] Ex. TURN-11 (Defever), pp. 5-6.

[1214] Ex. TURN-11 (Defever), p. 6.

[1215] Ex. TURN-11 (Defever), pp. 5, 7; Ex. SCE-06V06, p. 20 (Figure II-7).

Advocates also recommended a reduction to SCE's non-labor forecast for different reasons than TURN, proposing a total of $15.528 million for Environmental Programs O&M.[1216]

As explained in Ex. SCE-30, TURN, Cal Advocates, and SCE now jointly recommend a forecast of $19.270 million for Environmental Programs O&M, including $1.329 million in labor and $17.941 million in non-labor.[1217] This forecast is $3.418 million less than SCE's non-labor request, which was the area disputed by TURN and Cal Advocates. Exhibit SCE-30 also presents the forecast for Environmental Management and Development now jointly recommended by TURN, Cal Advocates, and SCE, of $18.539 million, including $2.566 million in labor and $15.973 million in non-labor.[1218]

During evidentiary hearings, SCE presented a statement of counsel to clarify the separation in this GRC between the Environmental Services activities and forecast and SCE's forecast for environmental support for vegetation management, which is a change from the 2021 GRC. SCE attorney Kris Vyas stated, "The stipulation in Exhibit SCE-30 relates to Exhibit SCE-06, Volume 6 on environmental services. It does not address revenues that are tracked in the Vegetation Management Balancing Accounting. Environmental services and the vegetation management [sic] are two separate areas in the rate case."[1219] TURN appreciates this clarification and agrees that it is important for the GRC decision to make clear that the costs and activities covered by the authorized forecast for Environmental Services (Exhibit SCE-06, Volume 6) will not be treated as Vegetation Management costs. This clarification will avoid any

[1216] Ex. SCE-30 (Environmental Services Stipulation), p. 2.

[1217] Ex. SCE-30 (Environmental Services Stipulation), p. 2.

[1218] Ex. SCE-30 (Environmental Services Stipulation), pp. 1-2.

[1219] 17 RT 1556: 8-13 (SCE/Vyas).

confusion regarding which costs SCE is authorized to record to the Vegetation Management Balancing Account or the other wildfire mitigation-related accounts in which SCE may track costs related to vegetation management.[1220]

In this GRC, Environmental Programs include activities to support compliance with environmental requirements relating to storm water management, air quality permitting, environmental clearance, hazardous waste management, spill prevention control and countermeasures, hazardous materials management and marine mitigation programs.[1221] Unlike the 2021 GRC, SCE's Environmental Programs request in this GRC does not include the costs associated with Environmental Support for Vegetation Management."[1222] Instead, SCE presents environmental support for vegetation management costs with its Vegetation Management request in Ex. SCE-02V10.[1223] As SCE explains, "In this 2025 GRC, SCE is separating environmental work that supports Vegetation Management activities from environmental work that supports other areas of the company (as described in exhibit SCE-06, Vol. 6, Section II)."[1224] As a result, SCE has charged costs for environmental support for Vegetation Management to the Vegetation Management BPE, and those costs are not reflected in SCE's Environmental Services BPE testimony.[1225] However, SCE's Environmental Management and Development request does include labor costs for "oversight of increased O&M work in the field primarily for vegetation

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[1220] *See* Ex. SCE-07V01, pp. 32-33 (presenting SCE's proposal for the Vegetation Management Balancing Account); D.24-03-008, pp. 7-9 (discussing SCE's Wildfire Mitigation Plan Memorandum Account and Fire Risk Mitigation Memorandum Account).

[1221] Ex. SCE-06V06, p. 17.

[1222] D.24-03-008, p. 43; Ex. SCE-06V06, p. 7.

[1223] Ex. SCE-02V10, p. 19, Table II-79, pp. 93-103.

[1224] Ex. SCE-02V10, p. 94.

[1225] Ex. SCE-06V06, p. 7.

management" and otherwise to support "a significant increase in O&M work to support strategic grid resiliency and green energy initiatives including vegetation management," among other activities.[1226]

Consistent with SCE's testimony and statement of counsel, and to avoid any confusion, TURN recommends that the Commission clarify that the forecast authorized for Environmental Services O&M covers the costs and activities included in SCE's Environmental Services request presented in Exhibit SCE-06V06, none of which are eligible for tracking in SCE's VMBA or other wildfire mitigation accounts for potential future cost recovery. This clarification will ensure that the full GRC forecast authorized for activities subject to the VMBA or other wildfire mitigation accounts is known and can be used to assess the incrementality of any additional costs that SCE may seek to recover in the future.[1227] It will also ensure that SCE has the appropriate incentive to manage its GRC-funded Environmental Services O&M costs.

32.2 Environmental Services Capital

TURN did not address SCE's forecasted Environmental Services capital expenditures. However, as explained in Exhibit SCE-30, TURN, Cal Advocates, and SCE now jointly recommend 2023-2025 capital expenditures of $7.375 million, which reflects a compromise between the recommendations of Cal Advocates and SCE.[1228]

[1226] Ex. SCE06V06, pp. 14-15.

[1227] In D.24-03-008, the Commission adopted specific requirements for SCE's showing of incrementality in future reasonableness reviews of wildfire mitigation-related costs, including "detailed information regarding program or activity level approved costs," with "page numbers, compared to actual expenditures and expenses, at the program and activity level." (D.24-03-008, pp. 19, 73).

[1228] Ex. SCE-30 (Environmental Services Stipulation), p. 3.

32.3 SDG&E Request For SONGS-Related Cost Recovery Re: Marine Mitigation

33. AUDIT SERVICES

34. ETHICS AND COMPLIANCE

35. SAFETY PROGRAMS

36. ENTERPRISE OPERATIONS

36.1 Transportation Services Department

36.2 Facilities And Land Operations

SCE forecasts 2023-2028 capital expenditures of roughly $1.5 billion (nominal dollars) for Facilities and Land Operations, including projects falling into five categories: Infrastructure Upgrades, Facility Repurpose Projects, Substation Reliability Upgrades, Facility Management Capital Projects, and the Land Operations Program.[1229] TURN addressed five of SCE's proposed capital projects in testimony, including two Infrastructure Upgrades, the Edison Training Academy and Vehicle Maintenance Facilities, two Facility Repurpose Projects, Alhambra Regional Operations Facility Renovations and Westminster Combined Facility Renovations, and one Land Operations project, the San Jacinto Laydown Yard.[1230] SCE previously received funding in at least one prior GRC for the first four of these projects without completing the work, and continues to be behind schedule on all five.

[1229] Ex. SCE-06V07, p. 51. A list of all capital projects included in SCE's request appears in Table II-4 at SCE-06V07, p. 52.

[1230] Ex. TURN-11 (Defever), pp. 6-14.

Under similar circumstances in SCE's 2021 GRC, the Commission addressed SCE's renewed funding requests for several Facility and Land Operations capital projects. The Commission recounted, "[W]hile the Commission has on numerous occasions reduced or disallowed costs of activities that were requested and included in prior GRC authorizations, the question of whether to approve a renewed funding request is fact-specific and must be evaluated on a case-by-case basis."[1231] As explained below, TURN recommends zero funding for these five projects because SCE previously received funding in at least one prior GRC, if not two, without completing the work, and/or SCE has not demonstrated that the projects will become operational during this GRC.[1232] For each project, TURN also offers an alternative recommendation in the event the Commission concludes that the project should be included in this GRC. In that case, TURN recommends that the Commission disallow the contingency included in SCE's capital forecast because contingencies are not known and measurable. TURN notes that Cal Advocates also takes issue with SCE's request for each of these five projects but proposes different remedies than TURN.[1233]

The following table summarizes the differences between TURN's primary and alternative recommendations and SCE's requests.

[1231] D.21-08-036, pp. 451-452.

[1232] SCE did not receive prior funding for the San Jacinto Laydown Yard.

[1233] Ex. CA-22 (Weaver), pp. 16 (recommending no funding for the Edison Training Academy with costs recorded to a memorandum account for recovery when the project is completed); 16 (recommending a 20% reduction in funding for Vehicle Maintenance Facilities); 24 (recommending a 20% reduction in funding for the Alhambra Regional Operations Facility Renovations); 25 (recommending a 20% reduction in funding for the Westminster Combined Facility Renovations); 29 (recommending a 20% reduction in funding for the San Jacinto Laydown Yard).

Facilities and Land Operations - 2023-2028 Capital (Nominal $000)				
Project	**SCE - Total**	**SCE - Contingency**	**TURN**	**TURN - Alternative**
Edison Training Academy (incl. T&D Equipment)	$277,199	$11,000	$0	$266,199
Vehicle Maintenance Facilities	$36,563	$2,000	$0	$34,563
Alhambra Regional Operations Facility Renovations	$93,494	$4,810	$0	$88,684
Westminster Combined Facility Renovations	$62,900	$3,126	$0	$59,774
San Jacinto Laydown Yard	$22,857	$1,000	$0	$21,857
Total TURN Adjustments			$493,013	$21,936

36.2.1 Edison Training Academy (formerly, T&D Training Center)

- The Commission should deny SCE's third request for funding for the Edison Training Academy, given prior funding authorizations in the 2018 and 2021 GRCs and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $11 million contingency.

SCE seeks funding to relocate and consolidate its T&D training operations from Chino, Westminster, and Alhambra, creating the Edison Training Academy. In the 2021 GRC, SCE proposed to relocate and consolidate its T&D training operations at its Rancho Vista site, located in the City of Rancho Cucamonga. Due to conditions mandated by the City of Rancho Cucamonga, SCE has since decided not to pursue the Rancho Vista site and is instead pursuing an SCE-owned site in Corona, California for the consolidated T&D training site.[1234] SCE now requests $277.199 million for the Edison Training Academy (2023-2028), including a risk

[1234] Ex. SCE-06V07, pp. 53-54.

contingency factor of 9.5% ($11.0 million) specific to this project.[1235] The Commission should deny this funding, or alternatively, at least disallow the contingency.

36.2.1.1 The Commission Should Deny Funding for this Project.

This is the third GRC in which SCE has requested funding for this project, formerly called the "T&D Training Center". SCE did not spend the authorized funding in the prior two GRCs. In the 2018 GRC, the Commission authorized $92 million for the T&D Training Center.[1236] From 2017 to 2018, SCE unsuccessfully attempted to purchase land for the project.[1237] Through 2019, SCE had only spent $2.132 million on the T&D Training Center.[1238] In the 2021 GRC, SCE requested $45.285 million for the T&D Training Center. The Commission approved "SCE's 2019 recorded and 2020-2021 capital expenditure forecast for the T&D Training Center" with the expectation that the project would "move forward as planned."[1239] The Commission noted, "There also does not appear to be any reason to suspect this project will continue to be delayed, since SCE has now secured a site for the new training center and has commenced planning and engineering work for the project." [1240] Nonetheless,

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[1235] Ex. SCE-06V07, p. 53; Ex. TURN-11 (Defever), p. 7. This cost estimate includes the Edison Training Academy plus related IT Infrastructure and Equipment, which SCE requests in Ex. SCE-06V07, plus T&D Equipment costs for the Edison Training Academy included in Ex. SCE-02V05.

[1236] D.21-08-036, p. 448 (discussing the authorization in the 2018 GRC).

[1237] Ex. TURN-11 (Defever), p. 7.

[1238] D.21-08-036, p. 449.

[1239] D.21-08-036, p. 454.

[1240] D.21-08-036, p. 453.

SCE spent only $3.6 million during 2018-2022, despite the second round of funding authorized in the 2021 GRC.[1241]

Considering this history, TURN witness Defever observed, "The Company's pattern of requesting funds for the project, collecting funds from ratepayers for the project, spending only a fraction of those funds on the project, and again requesting funds for the project decreases confidence that the project will be completed as requested."[1242] Because SCE has not provided sufficient reason to believe that the requested funds would be spent on the authorized project, TURN recommended in testimony that the Commission deny SCE additional funding in this GRC for the Edison Training Academy.[1243]

In rebuttal testimony, SCE asserts that project delays arose from circumstances beyond its control impacting the City of Corona's permitting process and timelines, but it has prioritized the work it could accomplish during the 2021 GRC cycle given the disruptions caused by the COVID-19 pandemic.[1244] SCE also states it has now "received the requisite permits, initiated Phase Zero and Phase 1 construction, and the project remains on track for completion on or before December 31, 2028."[1245] SCE notes that it recorded $4.5466 million on activities to further this project in 2022-2023 and has spent a total of $6.638 million so far.[1246]

[1241] Ex. TURN-11 (Defever), p. 7 (also noting that SCE spent $0.200 million prior to 2018 for this project, bringing the total to $3.8 million).

[1242] Ex. TURN-11 (Defever), p. 8.

[1243] Ex. TURN-11 (Defever), p. 9.

[1244] Ex. SCE-17V05, pp. 12-13.

[1245] Ex. SCE-17V05, p. 14.

[1246] Ex. SCE-17V05, p. 13.

TURN recognizes that SCE recorded $2.801 million for this project in 2023, bringing the total spending to $6.6 million.[1247] But this is a fraction of what was already collected from the 2018 GRC and 2021 GRCs. Moreover, SCE's 2023 spending was only 1/3 of SCE's forecast for 2023 in this GRC of $8.430 million.[1248] Given this continued delay and in consideration of the funding ratepayers have previously provided in the past two GRCs, the Commission should question the reliability of SCE's projected 2028 completion date and exclude funding for the Edison Training Center from this GRC. SCE can seek cost recovery for this project in its next GRC.

36.2.1.2 Alternatively, the Commission Should Disallow the Contingency.

SCE included a 9.5% contingency in its forecast for the Edison Training Academy, based on the risk assessment conduct by SCE in consultation with Cumming Management Group, Inc. (CMGI), the construction cost consulting firm SCE engages to create planning estimates for facility capital projects.[1249] According to SCE, the "project contingency accounts for risk of the need for additional expenditures."[1250] The Commission has considered utility requests for contingencies in cost forecasts in a number of proceedings over time and when challenged, has generally reviewed contingencies with skepticism because they reduce utility incentives to control costs. As the Commission recounted most recently in D.24-03-042, "It has long been our practice, consistent with ratemaking policy, to disallow contingencies in order to motivate

[1247] Ex. SCE-17V05, p. 9 (Table II-9).

[1248] Ex. SCE-17V05, p. 9 (Table II-9)(2023 Recorded); Ex. SCE-06V07, p. 53, Table II-6 (2023 Forecast for Edison Training Academy plus IT Infrastructure and Equipment).

[1249] Ex. SCE-06V07, p. 44; Ex. TURN-11 (Defever), p. 7.

[1250] Ex. SCE-06V07, p. 46.

utilities to remain within their forecast budgets for their capital projects, and wherever possible to "do it for less" as a way to benefit both ratepayers and shareholders."[1251]

For example, in the SCE 2021 GRC, the Commission considered SCE's request for contingency factors in the Seismic Assessment and Mitigation Program, which includes assessment of SCE's electric and non-electric facilities, generation infrastructure, and telecommunications/IT infrastructure to identify necessary seismic mitigations, followed by implementation of necessary retrofits and improvements.[1252] SCE's forecast included, in pertinent part, a 35 percent contingency for the assessment and retrofit of 16 "Mechanical Electrical Equipment Rooms" within the Transmission Substation Mitigation category and a 1.5 percent contingency rate for the Non-Electric Facilities category.[1253] The Commission rejected contingencies for these projects, despite SCE's claim that use of contingency factors "is an industry standard practice to account for unknown or unforeseen conditions," as well as SCE's suggestion that the proposed seismic mitigation projects at transmission substations carry a particular risk of unforeseen field conditions during the construction phase.[1254] The Commission reasoned:

> As explained in D.19-05-020, budgeting for contingencies is not necessarily appropriate in the context of a general rate case, where the utility must demonstrate the reasonableness of every dollar in its forecasted revenue requirement. Since contingency allowances are, by SCE's own admission, intended to cover "unforeseen conditions," these amounts are also unpredictable,

[1251] D.24-03-042 (Cal Water 2023 GRC), p. 25.

[1252] D.21-08-036, pp. 325-326.

[1253] D.21-08-036, pp. 327-328 (discussing Cal Advocates' and TURN's objections to SCE's requests for contingencies).

[1254] D.21-08-036, pp. 330-331.

and therefore, we find that SCE has not established these costs to be reasonable.[1255]

The Commission further emphasized that disallowing all of SCE's requested contingencies – including the 35 percent and 15 percent contingencies – "should motivate SCE to remain within its forecast budgets for these projects.[1256] Finally, the Commission noted, "If additional funds become necessary SCE may seek to establish that necessity in the next GRC."[1257]

Likewise in SCE's TY 2018 GRC, the Commission considered, and rejected, SCE's request for a range of contingencies for Capitalized Software projects. The Commission looked beyond SCE's claims that inclusion of contingencies in project cost estimates for IT is routine and in line with industry standards, focusing instead on whether contingencies are appropriate in general rate cases. The Commission considered SCE's responsibility to "demonstrate the reasonableness of every dollar in its revenue requirement" in a GRC, a showing absent given SCE's justification that "contingencies are necessary for the 'uncertainties and variables that are unknown'."[1258] The Commission further considered the balance of ratepayer and shareholder interests in the GRC framework, where "any savings the utility can generate between general rate cases belong to the shareholders," and "in exchange for this opportunity, the shareholders take on the burden of added expenses it may incur during a rate case cycle."[1259] The Commission explained why requiring SCE to "forecast what it projects to be a reasonable

[1255] D.21-08-036, p. 331.

[1256] *Id.*

[1257] *Id.*

[1258] D.19-05-020, p. 150.

[1259] D.19-05-020, p. 151.

expense" balances the interests of ratepayers and shareholders in the GRC framework.[1260] The Commission then concluded, "Consistent with ratemaking policy, disallowing these contingencies should motivate SCE to remain within its forecast budgets for these projects. If additional funds become necessary, SCE may seek to establish that necessity in the next GRC."[1261]

On the other hand, the Commission has authorized contingencies under certain circumstances. For instance, in D.06-11-048, the Commission granted a five percent contingency factor for PG&E on total project cost for the Humboldt powerplant.[1262] Similarly, the Commission authorized a five percent contingency factor for SCE on total project cost for the Mountainview powerplant.[1263] In D.10-02-032, the Commission granted PG&E a 7.9 percent contingency on its new Advanced Metering Infrastructure ("AMI") system and a 12.9 percent contingency on its Smart Meter upgrade project, but refused any contingency amount for PG&E's Dynamic Pricing programming project.[1264] In D.19-09-051, the Commission authorized SoCalGas's request for Pipeline Safety Enhancement Plan (PSEP) project contingencies, but limited contingencies to an average of 15 percent.[1265]

[1260] D.19-05-020, pp. 151-152.

[1261] D.19-05-020, p. 152. *See also* D.19-09-025 (PG&E 2019 Gas Transmission and Storage Rate Case), pp. 229-230 (agreeing with TURN that PG&E's request for a contingency factor in its forecast for the Right-of-Way Maintenance program for gas transmission system pipeline facilities should be denied); D.14-08-032 (PG&E 2014 GRC), pp. 130, 135-136 (denying PG&E's requests for two contingency factors: a $7.2 million contingency for constructing training facilities and an 18 percent contingency factor for the Electric Distribution (Electric and Gas) and Workforce Mobilization and Scheduling project).

[1262] D.06-11-048, pp. 21-22.

[1263] D.03-12-059, p. 49.

[1264] D.10-02-032, pp. 128-129.

[1265] *See* D.19-09-051, pp. 205 (hydrotest projects), 215 (capital PSEP projects).

Generally speaking, where stakeholders have challenged utility requests for contingencies, the Commission's approach has been one of caution. The Commission has properly sought to avoid disturbing the balance of interests between shareholders and ratepayers embedded in cost of service ratemaking.[1266] This same balance should guide the Commission here in considering SCE's proposed contingencies. With capital project costs included in GRC base rates, the larger the contingency factor, the less risk to the shareholders because the ratepayers are covering more of the identified uncertainties. Shifting more risk to ratepayers reduces the utility's incentive to control costs. As such, the Commission should deny SCE's request for a 9.5% contingency for the Edison Training Academy if it authorizes any funding for the project in this GRC.

In rebuttal testimony, SCE argues that the use of contingencies is "an industry-standard practice that accounts for unforeseen conditions arising during the construction phase."[1267] However, the Commission made clear in the 2018 GRC and 2021 GRC that the question is not whether the inclusion of contingencies is routine and in line with industry standards.[1268] Rather, the question is whether contingencies are appropriate in general rate cases given the utility's burden and the balance of ratepayer and shareholder interests in the GRC framework, where "any savings the utility can generate between general rate cases belong to the shareholders," and "in exchange for this opportunity, the shareholders take on the burden of added expenses it may incur during a rate case cycle."[1269]

[1266] *See* D.24-03-042, pp. 25-26 (quoting D.19-05-020, which in turn quoted D.85-03-042).

[1267] Ex. SCE-17V05, p. 14.

[1268] *See* D.19-05-020, pp. 150-152; D.21-08-036, pp. 330-331.

[1269] D.19-05-020, p. 151.

SCE further argues that TURN's challenge to contingencies should be rejected "since SCE is using the same estimating methodology previously found reasonable by the Commission" in the 2021 GRC decision.[1270] In the 2021 GRC, TURN challenged the sufficiency of SCE's total cost estimate for each project; TURN did not challenge the inclusion of a contingency specifically. As the Commission recounts in D.21-08-036, "TURN also asserts that SCE failed to meet its burden to justify the cost of each project: in response to a request for additional supporting documentation, SCE provided a single page cost summary from CCMI without any specific bids, contracts, invoices, or other supporting documentation."[1271] The Commission addressed the concern TURN raised, finding that SCE's estimates were "sufficiently detailed and supported, and the estimated level of costs reasonable."[1272] The Commission did not resolve any dispute over a contingency, as none was raised.

In this GRC, TURN has specifically challenged SCE's inclusion of a contingency for facilities construction projects, and the Commission must consider the merits of that challenge as presented here. For the foregoing reasons, the Commission should find that SCE's requested contingency should be denied.

36.2.2 Vehicle Maintenance Facilities

- The Commission should deny SCE's third request for funding for the Vehicle Maintenance Facilities project, given prior funding authorization in the 2018 and

[1270] Ex. SCE-17V05, pp. 15-16.

[1271] D.21-08-036, p. 449. *See also* TURN Opening Brief, filed in A.19-08-013 on 9/11/20, pp. 234-235 (challenging SCE's support for T&D Training Center cost estimate), 235-236 (challenging SCE's support for Vehicle Maintenance Facilities cost estimate), 237 (challenging SCE's support for Devers Maintenance and Test Building cost estimate), 238 (challenging SCE's Rector Maintenance and Test Building cost estimate) available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M347/K127/347127665.PDF.

[1272] D.21-08-036, pp. 453-454 (T&D Training Center), 455 (Devers and Rector Maintenance and Test Buildings).

SCE's failure to meet the Commission's requirements for additional funding in the 2021 GRC. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $2 million contingency.

SCE forecasts total 2023-2028 expenditures of $36.563 million to renovate the vehicle maintenance facilities at the Orange Coast and Montebello service centers and demolish and rebuild the vehicle maintenance facility at the Ventura service center.[1273] SCE's forecast includes a risk contingency factor of 7.1% ($2.0 million) specific to this project.[1274] The Commission should deny this funding, or alternatively, at least disallow the contingency.

36.2.2.1 The Commission Should Deny Funding for this Project.

This is SCE's third request for funding to renovate these three vehicle maintenance facilities. In the 2018 GRC, SCE requested and the Commission authorized $22.374 million.[1275] SCE then spent $0 from 2018-2020.[1276] SCE again requested $22.646 million in the 2021 GRC, but the Commission denied that request, explaining that it would "not authorize additional funding for this project without some showing that progress has been made."[1277] The Commission noted that the delays associated with the project were "entirely within SCE's control."[1278]

[1273] Ex. SCE-06V07, pp. 52, 67. This amount includes both the Vehicle Maintenance Facilities project and related IT Infrastructure and Equipment.

[1274] Ex. TURN-11 (Defever), p. 10.

[1275] Ex. TURN-11 (Defever), p. 9.

[1276] Ex. TURN-11 (Defever), p. 9.

[1277] D.21-08-036, pp. 449, 454.

[1278] D.21-08-036, p. 454.

The Commission should find that SCE has failed to meet its burden of demonstrating the reasonableness of additional funding at this time. As TURN explained in testimony, TURN asked SCE to explain in detail what specific progress has been made since the last GRC, and SCE's response provided a bulleted list of tasks it has completed. [1279] However, in 2021 and 2022, SCE spent only $120,000 and $246,000, respectively, a fraction of what was already collected from the 2018 GRC.[1280] As such, it does not appear significant progress has been made. Further, SCE anticipates that the project will not be completed until 2028 and vehicles will not be sent to the three new facilities until 2029, the year after this GRC cycle ends. For this reason, SCE did not include any cost reductions in this GRC from no longer needing to send vehicles to alternative service facilities.[1281] Finally, it is unclear whether funds authorized in this GRC would be used for this project, as SCE acknowledges that other pending Facility and Land Operations projects are higher priority.[1282]

In rebuttal testimony, SCE explains that it spent $720,000 in 2023, more than its 2023 estimate of $500,000, and maintains that the projects are on schedule to be completed by the end of this GRC cycle, despite permitting process backlogs, the need to solicit construction bids, and, of course, the realities of construction.[1283] While the proverbial ball may now be rolling, it is rolling very slowly. SCE has spent just over $1 million on this project, first presented and

[1279] Ex. TURN-11 (Defever), p. 10.

[1280] Ex. TURN-11 (Defever), p. 10.

[1281] Ex. TURN-11 (Defever), p. 10.

[1282] Ex. SCE-06V07, p. 65.

[1283] Ex. SCE-17V05, pp. 19-20.

funded in the 2018 GRC. The Commission should find that SCE is yet to make sufficient progress for additional funding, as required by D.21-08-036.[1284]

36.2.2.2 Alternatively, the Commission Should Disallow the Contingency.

SCE's forecast includes a risk contingency factor of 7.1% ($2.0 million) for the Vehicle Maintenance Facilities project, based on the risk assessment conduct by SCE in consultation with CMGI, the construction cost consulting firm SCE engages to create planning estimates for facility capital projects.[1285] According to SCE, the "project contingency accounts for risk of the need for additional expenditures."[1286]

TURN addresses the inappropriateness of requiring ratepayers to pay for contingencies in responding to SCE's proposed contingency for the Edison Training Academy above. As TURN explains there, the Commission has previously sought to avoid disturbing the balance of interests between shareholders and ratepayers embedded in cost of service ratemaking when stakeholders have challenged contingencies. The Commission has been mindful of the fact that contingencies shift risk for identified uncertainties from shareholders to ratepayers and reduce the utility's incentive to control costs. To avoid disturbing this balance, the Commission should deny SCE's request for a 7.1% contingency for the Vehicle Maintenance Facilities if it authorizes any funding for the project in this GRC.

In rebuttal testimony, SCE repeats the same arguments in defense of its contingency as for the Edison Training Center, specifically that the Commission found SCE's cost estimating

[1284] D.21-08-036, p. 454.

[1285] Ex. SCE-06V07, p. 44; Ex. TURN-11 (Defever), p. 10.

[1286] Ex. SCE-06V07, p. 46.

methodology reasonable in the last GRC and should accordingly reject TURN's challenge to the contingency here.[1287] TURN has already addressed these arguments above and does not repeat them here.

36.2.3 Alhambra Regional Operations Facility Renovations

- The Commission should deny SCE's second request for funding for the Alhambra Regional Operations Facility Renovations, given the prior funding authorization in the 2021 GRC and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $4.810 million contingency.

SCE forecasts total 2023-2028 capital expenditures of $93.494 million to renovate 6 of the 12 buildings located at the Alhambra Regional Operations Facility.[1288] SCE claims that the project is necessary as the average building age is 87 years old and the average FCI scores of the six buildings is 19% (Poor Condition).[1289] SCE's forecast includes a risk contingency factor of 8.9% ($4.810 million) specific to this project.[1290] The Commission should deny this funding, or alternatively, at least disallow the contingency.

36.2.3.1 The Commission Should Deny Funding for this Project.

In the 2021 GRC, SCE forecasted $58.608 million for this project, which was uncontested and approved by the Commission.[1291] However, SCE spent only $3.815 million

[1287] Ex. SCE-17V05, pp. 21-22.

[1288] Ex. SCE-06V07, pp. 52, 107. This amount includes both the Alhambra Regional Operations Facility Renovations project and related IT Infrastructure and Equipment.

[1289] Ex. SCE-06V07, p. 108.

[1290] Ex. TURN-11 (Defever), p. 12.

[1291] Ex. TURN-11 (Defever), p. 13.

from 2018-2022.[1292] Based on SCE's underspending on this project, TURN questioned whether SCE would spend the requested funds on this project if approved and recommended that the Commission disallow the costs for this project.[1293]

In rebuttal testimony, SCE argues that it recorded $6.380 million in 2023 "to further this project's activities," bringing the total recorded spend to $10.389 million.[1294] SCE claims that this spending shows SCE's commitment to completing this project as forecast during this GRC cycle and meeting the in-service date of December 31, 2028.[1295] But SCE fell much further behind its anticipated schedule in 2023, when SCE forecast spending $22.913 million "to obtain permits and begin construction of the prefabricated warehouse and the new parking layout, Building D demolition and, planning for the Building AD battery storage expansion."[1296] SCE explains that permitting delays at the City of Alhambra have slowed this project down. SCE also cites the need for state and federal approval of soil contamination remediation plans as the cause of a nine month delay in 2023 to the schedules for the Building D demolition and new warehouse construction.[1297]

Given the years of compounding delays, it is unclear whether SCE will be able to finish this project on time, particularly given its construction schedule which runs through 2028.[1298] Based on this history, the Commission should decline to provide SCE with additional funding in

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[1292] Ex. TURN-11 (Defever), p. 13.

[1293] Ex. TURN-11 (Defever), p. 13.

[1294] Ex. SCE-17V05, p. 42.

[1295] Ex. SCE-17V05, p. 42.

[1296] Ex. SCE-06V07, p. 107.

[1297] Ex. SCE-17V05, p. 43.

[1298] Ex. SCE-06V07, pp. 110-111.

this GRC. SCE can include the Alhambra Regional Operations Facility Renovations in its next GRC.

36.2.3.2 Alternatively, the Commission Should Disallow the Contingency.

SCE's forecast includes a risk contingency factor of 8.9% ($4.810 million) for the Alhambra Regional Operations Facility Renovations, based on the risk assessment conduct by SCE in consultation with CMGI, the construction cost consulting firm SCE engages to create planning estimates for facility capital projects.[1299] According to SCE, the "project contingency accounts for risk of the need for additional expenditures."[1300]

TURN addresses the inappropriateness of requiring ratepayers to pay for contingencies in responding to SCE's proposed contingency for the Edison Training Academy above. As TURN explains there, the Commission has previously sought to avoid disturbing the balance of interests between shareholders and ratepayers embedded in cost of service ratemaking when stakeholders have challenged contingencies. The Commission has been mindful of the fact that contingencies shift risk for identified uncertainties from shareholders to ratepayers and reduce the utility's incentive to control costs. To avoid disturbing this balance, the Commission should deny SCE's request for a 8.9% contingency for the Alhambra Regional Operations Facility Renovations if it authorizes any funding for the project in this GRC.

In rebuttal testimony, SCE repeats the same arguments in defense of its contingency as for the Edison Training Center, specifically that the Commission found SCE's cost estimating methodology reasonable in the last GRC and should accordingly reject TURN's challenge to the

[1299] Ex. SCE-06V07, p. 44; Ex. TURN-11 (Defever), p. 12.

[1300] Ex. SCE-06V07, p. 46.

contingency here.[1301] TURN has already addressed these arguments above and does not repeat them here.

36.2.4 Westminster Combined Facility Renovations

- The Commission should deny SCE's second request for funding for the Westminster Combined Facility Renovations, given the prior funding authorization in the 2021 GRC and ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $3.216 million contingency.

SCE forecasts total 2023-2028 capital expenditures of $62.900 million to renovate the Westminster Combined Facility to enhance safety, compliance, and efficiency.[1302] SCE's forecast includes a risk contingency factor of 8.0% ($3.126 million) specific to this project.[1303] The Commission should deny this funding, or alternatively, at least disallow the contingency.

36.2.4.1 The Commission Should Deny Funding for this Project.

In the 2021 GRC, SCE forecasted $26.653 for this project, which was uncontested and approved by the Commission.[1304] However, SCE spent hardly more than $3 million from 2018-2022.[1305] Based on SCE's underspending on this project, TURN questioned whether SCE would spend the requested funds on this project if approved and recommended that the Commission disallow the costs for this project.[1306]

[1301] Ex. SCE-17-V05, pp. 43-44.

[1302] Ex. SCE-06V07, pp. 52, 111-E3-112. This amount includes both the Westminster Combined Facility Renovations project and related IT Infrastructure and Equipment.

[1303] Ex. TURN-11 (Defever), p. 11.

[1304] Ex. TURN-11 (Defever), p. 11.

[1305] Ex. TURN-11 (Defever), p. 11 (citing $3.015 million in 2018-2022 spending, based on TURN-SCE-031, Q.1); Ex. SCE-06V07, p. 111-E3 (showing $3.133 million in pre-2023 spending).

[1306] Ex. TURN-11 (Defever), p. 11.

In rebuttal testimony, SCE argues that it recorded $5.787 million in 2023 "to further this project's activities," bringing the total recorded spend to $8.9 million.[1307] SCE claims that this spending shows SCE's commitment to completing this project as forecast during this GRC cycle and meeting the in-service date of December 31, 2028.[1308] But SCE fell further behind its anticipated schedule in 2023. SCE forecast spending $7.217 million in 2023 to "continue construction of the yard configuration and begin planning for the MSS and LARS buildings."[1309]

Given SCE's track record, the Commission should decline to provide SCE with additional funding in this GRC. SCE can include the Westminster Combined Facility Renovations in its next GRC.

36.2.4.2 Alternatively, the Commission Should Disallow the Contingency.

SCE's forecast includes a risk contingency factor of 8.0% ($3.126 million) for the Westminster Combined Facility Renovations, based on the risk assessment conduct by SCE in consultation with CMGI, the construction cost consulting firm SCE engages to create planning estimates for facility capital projects.[1310] According to SCE, the "project contingency accounts for risk of the need for additional expenditures."[1311]

TURN addresses the inappropriateness of requiring ratepayers to pay for contingencies in responding to SCE's proposed contingency for the Edison Training Academy above. As TURN explains there, the Commission has previously sought to avoid disturbing the balance of interests

[1307] Ex. SCE-17V05, p. 47.

[1308] Ex. SCE-17V05, pp. 47-49.

[1309] Ex. SCE-06V07, p. 111-E3, Table II-25; p. 114.

[1310] Ex. SCE-06V07, p. 44; Ex. TURN-11 (Defever), p. 11.

[1311] Ex. SCE-06V07, p. 46.

between shareholders and ratepayers embedded in cost of service ratemaking when stakeholders have challenged contingencies. The Commission has been mindful of the fact that contingencies shift risk for identified uncertainties from shareholders to ratepayers and reduce the utility's incentive to control costs. To avoid disturbing this balance, the Commission should deny SCE's request for a 8.0% contingency for the Westminster Combined Facility Renovations if it authorizes any funding for the project in this GRC.

In rebuttal testimony, SCE repeats the same arguments in defense of its contingency as for the Edison Training Center, specifically that the Commission found SCE's cost estimating methodology reasonable in the last GRC and should accordingly reject TURN's challenge to the contingency here.[1312] TURN has already addressed these arguments above and does not repeat them here.

36.2.5 San Jacinto Laydown Yard

- The Commission should deny SCE's request for funding for the San Jacinto Laydown Yard, given ongoing project delays. Alternatively, if the Commission concludes the funding for this project is appropriate, the Commission should disallow SCE's requested $1 million contingency.

SCE forecasts total 2023-2028 capital expenditures of $22.857 million to purchase and improve approximately 20 acres to construct a distribution laydown yard for storage and staging in the San Jacinto region.[1313] SCE currently leases two laydown yards in the San Jacinto district, which are inadequate to meet the area's present and future materials laydown demands.[1314] Additionally, SCE states that those leases expire in 2025 and may not be renewed by the

[1312] Ex. SCE-17-V05, pp. 50-51.

[1313] Ex. SCE-06V07, pp. 52, 158.

[1314] Ex. SCE-06V07, p. 159.

property owner.[1315] SCE plans to purchase land, perform due diligence, secure entitlements, improve the site, and construct a building.[1316] SCE's forecast includes a risk contingency factor of 8.3% ($1.0 million) specific to this project.[1317] The Commission should deny this funding, or alternatively, at least disallow the contingency.

36.2.5.1 The Commission Should Deny Funding for this Project.

A significant portion of the costs for this project are for the purchase of the land (more than 25%).[1318] However, as of January 2, 2024, the Company had not found or identified the land that it intends to purchase.[1319] As the identity and cost of the land are not known, this cost is not known and measurable. It is also unknown when or if this purchase will even occur. For example, as discussed above, SCE received funding in the 2018 GRC to purchase land for the T&D Training Center but ultimately did not purchase that land.[1320] Without the land purchase, there will be no site improvements or building construction for the laydown yard. For these reasons, TURN recommended the disallowance of the entire amount, a reduction of $22.857 million.[1321]

In rebuttal testimony, SCE recounted its "due diligence for numerous properties," including submitting Letters of Intent to purchase properties in August 2023 and December

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[1315] Ex. SCE-06V07, p. 159.

[1316] Ex. SCE-06V07, p. 160.

[1317] Ex. TURN-11 (Defever), p. 13.

[1318] Ex. SCE-06V07 WP Book C, p. 85.

[1319] Ex. TURN-11 (Defever), p. 13.

[1320] Ex. TURN-11 (Defever), p. 7.

[1321] Ex. TURN-11 (Defever), p. 14.

2023, but the respective property owners withdrew their offers to sell during the due diligence process.[1322] SCE clarified that it "located a suitable parcel in Hemet with an existing warehouse" in October 2023, submitted a Letter of Intent in April 2024, and has now commenced due diligence.[1323] While SCE "expects to occupy the property later this year," the property owners could backout, as happened after SCE's last two Letters of Intent, or SCE could determine that the property will not meet its needs.[1324]

Despite these continuing challenges, SCE suggests that its "efforts to purchase a suitable parcel remain ongoing and consistent with the forecast and schedule presented in its direct testimony."[1325] Yet SCE recorded no expenditures in 2023, despite forecasting $508,000 related to site acquisition.[1326] Additionally, SCE stated, "In the absence of the acquisition of suitable land by *early 2024*, SCE will need to seek lease extensions from property owners and obtain agreements from local jurisdictions to allow for temporary laydown yard use while a permanent solution is sought."[1327]

The Commission should find that the status of this project continues to be worrisome, despite SCE's efforts. As such, the Commission should deny the requested funding. SCE can include the San Jacinto Laydown Yard in its next GRC if the project comes to fruition.

[1322] Ex. SCE-17V05, p. 60.

[1323] Ex. SCE-17V05, pp. 59, 61.

[1324] Ex. SCE-17V05, p. 59.

[1325] Ex. SCE-17V05, p. 61.

[1326] Ex. SCE-06V07, p. 160; Ex. SCE-17V05, p. 58.

[1327] Ex. TURN-11 (Defever), Appendix B, TURN-SCE-031, Q. 42 (emphasis added).

36.2.5.2 Alternatively, the Commission Should Disallow the Contingency.

SCE's forecast includes a risk contingency factor of 8.3% ($1.0 million) for the San Jacinto Laydown Yard, based on the risk assessment conduct by SCE in consultation with CMGI, the construction cost consulting firm SCE engages to create planning estimates for facility capital projects.[1328] According to SCE, the "project contingency accounts for risk of the need for additional expenditures."[1329]

TURN addresses the inappropriateness of requiring ratepayers to pay for contingencies in responding to SCE's proposed contingency for the Edison Training Academy above. As TURN explains there, the Commission has previously sought to avoid disturbing the balance of interests between shareholders and ratepayers embedded in cost of service ratemaking when stakeholders have challenged contingencies. The Commission has been mindful of the fact that contingencies shift risk for identified uncertainties from shareholders to ratepayers and reduce the utility's incentive to control costs. To avoid disturbing this balance, the Commission should deny SCE's request for a 8.3% contingency for the San Jacinto Laydown Yard if it authorizes any funding for the project in this GRC.

In rebuttal testimony, SCE repeats the same arguments in defense of its contingency as for the Edison Training Center, specifically that the Commission found SCE's cost estimating methodology reasonable in the last GRC and should accordingly reject TURN's challenge to the

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[1328] Ex. SCE-06V07, p. 44; Ex. TURN-11 (Defever), p. 13.

[1329] Ex. SCE-06V07, p. 46.

contingency here.[1330] TURN has already addressed these arguments above and does not repeat them here.

37. POLICY, EXTERNAL ENGAGEMENT, AND RATEMAKING

37.1 Develop And Manage Policy And Initiatives

37.2 Education, Safety, And Operations

The Education, Safety and Operations GRC activity consists of work performed within SCE's Local Public Affairs organization.[1331] SCE's forecast for Education, Safety and Operations in rebuttal testimony is $7.630 million, a reduction to its original request of $7.723 million due to incremental savings associated with SCE's "Operational Excellence" efforts.[1332] SCE's forecast is an increase of nearly $1.5 million over 2022 recorded costs of $6.193 million.[1333] This increase covers labor for 3 new positions and filling vacancies plus non-labor for increased stakeholder workshops, increases in costs that had decreased due to COVID-19, and increased distribution work including a specialized consultant for community outreach.[1334] The Commission should instead adopt TURN's forecast of $6.193 million, which is the 2022 last recorded year.

As TURN demonstrated in testimony, SCE has consistently underspent on Education, Safety and Operations since 2018, and SCE's recorded costs declined every year from 2019-

[1330] Ex. SCE-17V05, pp. 62-63.

[1331] Ex. SCE-17V06, p. 5.

[1332] Ex. SCE-17V06, pp. 6 (Table II-5), 8 (explaining that SCE reduced its forecast by $0.093 million to account for eliminating two of the vacant administrative assistant positions in this department).

[1333] Ex. SCE-17V06, p. 6 (Table II-5); Ex. SCE-06V08, p. 23.

[1334] Ex. SCE-06V08, pp. 23-25.

2022.[1335] In fact, both of these trends continued in 2023, as the table below illustrates, despite SCE's forecast in this GRC that spending would increase in 2023 to $6.795 million.[1336]

Education, Safety and Operations (Constant 2022 $000s)						
	2018	2019	2020	2021	2022	2023
Authorized	$9,761	$9,761	$9,761	$8,056	$8,056	$8,056
Actual	$7,519	$8,131	$7,819	$6,319	$6,193	$6,001
Underspent	$2,242	$1,630	$1,942	$1,737	$1,863	$2,055

SCE underspent relative to both authorized labor and non-labor amounts in each year from 2018-2023, not only total spending.[1337]

Given SCE's history of overforecasting for this activity, in years preceding and following the COVID-19 pandemic, the Commission should dismiss SCE's claims that it must increase spending in 2025 so significantly above recent levels. Authorizing a forecast of 2022 last recorded year is reasonable in light of the consistent decline in spending from 2019 through 2023.[1338] It is also higher than SCE's actual spending in 2023 for both labor and non-labor.[1339] Accordingly, the Commission should adopt TURN's forecast of $6.193 million for Education, Safety and Operations, including $5.615 million for labor and $0.578 for non-labor.

[1335] Ex. TURN-11 (Defever), pp. 14-15. As noted in fn. 44 on page 14, the authorized amounts shown are test year authorizations without the increases provided through the post test year adjustment mechanism authorized in the 2018 GRC for 2019 and 2020, and in the 2021 GRC for 2022 and 2023.

[1336] Ex. TURN-11 (Defever), p. 15; Ex. SCE-06V08, p. 22 (Figure II-5); Ex. SCE-11, Appendix A (2023 Recorded O&M).

[1337] Ex. SCE-06V08, p. 22 (Figure II-5, recorded L, NL 2018-2022); Ex. SCE-11, Appendix A (2023 Recorded O&M – L, NL); Ex. TURN-11 (Defever), Appendix B, TURN-SCE-033, Q.04 (L, NL authorized in 2018 and 2021 GRCs).

[1338] D.04-07-022 (SCE 2003 GRC), p. 15 (quoting D.89-12-057) ("If recorded expenses in an account have shown a trend in a certain direction over three or more years, the [last recorded year] level is the most recent point in the trend and is an appropriate base estimate for [the test year].").

[1339] Ex. SCE-06V08, p. 22 (Figure II-5, recorded L, NL 2018-2022); Ex. SCE-11, Appendix A (2023 Recorded O&M – L, NL).

37.3 Professional Education And Development

SCE forecasts $2.113 million for Professional Education and Development, which consists of dues and memberships for seven professional organizations.[1340] In TURN's testimony, TURN opposed part of SCE's request for Edison Electric Institute (EEI) dues, recommending an adjustment of $0.770 million.[1341] TURN additionally opposes SCE's request for $0.042 million in California Taxpayers Association (CalTax) dues, an issue not addressed in TURN's testimony. With these adjustments, TURN's forecast is $1.301 million. The Commission should adopt TURN's forecast for Professional Education and Development for the reasons explained below.

37.3.1 The Commission should reduce SCE's forecast for EEI dues.

SCE's Professional Education and Development forecast includes $1.844 million for Edison Electric Institute (EEI) dues.[1342] The EEI forecast includes $15,000 for the Restoration, Operations, and Crisis Management Program, which TURN supports. SCE removed from its request the portion of EEI dues identified in the EEI invoice as related to lobbying and charitable activities, including 13% of expenses classified as "Regular Activities of Edison Electric Institute," 20% of "Industry Issues" activities, and 100% of "Contribution to the Edison Foundation."[1343] TURN recommends a further reduction of $770,000 because SCE has not met the Commission's clear requirements for demonstrating the reasonableness of requested funding

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[1340] Ex. SCE-06V08 WP, p. 27.

[1341] Ex. TURN-11, p. 17.

[1342] Ex. SCE-06V08 WP, p. 27. SCE elsewhere refers to its request of $1.893 million for EEI dues. Ex. SCE-06V08, p. 38; Ex. SCE-17V06, p. 9.

[1343] Ex. SCE-06V08, pp. 38-39.

for EEI dues.[1344] With TURN's reduction, ratepayers would fund 50% of EEI dues, plus the full amount for Restoration, Operations, and Crisis Management Program.

The Commission has addressed the extent to which ratepayers should pay for a utility's EEI dues in a number of recent GRCs. For example, in D.15-11-021, issued in SCE's 2015 GRC, the Commission reiterated the specific types of activities conducted by EEI for which ratepayers should *not* pay. Those activities include the following six cost categories, as defined by the National Association of Regulatory Utility Commissioners (NARUC): (1) Legislative Advocacy, (2) Legislative Policy Research, (3) Regulatory Advocacy, (4) Advertising, (5) Marketing, and (6) Public Relations.[1345] In that case, SCE had removed costs labeled "Lobbying" plus "Advertising, Marketing, and Public and Media Relations."[1346] The Commission concluded that the "Lobbying" category overlaps with NARUC's "Legislative Advocacy" category but does not include the categories of "Legislative Policy Research" and "Regulatory Advocacy," which must also be excluded because they are political in nature.[1347] In D.21-08-036, issued in SCE's 2021 GRC, the Commission similarly recounted, "The Commission has specifically barred ratepayer funding of membership activities such as: legislative advocacy, legislative policy research, regulatory advocacy, advertising, marketing, and public relations."[1348] There the Commission noted that SCE had not provided "a breakdown of EEI's membership activities or dues that would enable the Commission to determine how

[1344] Ex. TURN-11 (Defever), p. 17.

[1345] D.15-11-021, pp. 363-366.

[1346] D.15-11-021, p. 365.

[1347] D.15-11-021, pp. 365-366.

[1348] D.21-08-036, p. 462. *See also* D.19-05-020, issued in the SCE 2018 GRC, p. 250 (rejecting SCE's reliance on the EEI invoice to establish which portion of EEI dues ratepayers should fund and concluding that SCE had not met is burden to establish any portion of the dues were recoverable from ratepayers).

much of the dues are attributable to activities the Commission has previously deemed improper for ratepayer recovery."[1349]

Where utilities have not met their burden to demonstrate the reasonableness of requested EEI dues, the Commission has authorized a lower forecast. For instance, in SCE's 2015 GRC, the Commission authorized a forecast of $1.0 million, roughly $0.5 million less than SCE's request ($1.462 million) and approximately half of the full dues amount ($1.922 million).[1350] In SCE's 2018 GRC, the Commission found that SCE had not met its burden to establish that any portion of EEI dues are recoverable from ratepayers and denied recovery.[1351] In the 2021 GRC, SCE devoted 7 pages of its direct testimony to describing the many benefits of EEI membership for customers falling into the following categories: disaster preparedness, grid resiliency, customer savings, information exchange, and miscellaneous activities that benefit SCE customers.[1352] Finding SCE's showing sufficient to demonstrate that EEI membership confers "some ratepayer benefits," the Commission determined that "some ratepayer funding for SCE's EEI membership dues" should be approved.[1353] The Commission authorized the portion of dues for the Restoration, Operations, and Crisis Management Program, plus 50% of the remainder of dues, for a total forecast of $0.983 million.[1354]

In this GRC, SCE devoted 9 pages of its direct testimony to describing the same customer benefits from EEI membership as SCE detailed in its 2021 GRC (disaster preparedness, disaster

[1349] D.21-08-036, p. 462.

[1350] D.15-11-021, pp. 363, 366.

[1351] D.19-05-020, p. 250.

[1352] D.21-08-036, p. 461 (citing Ex. SCE-06, Vol. 6, pp. 19-25).

[1353] D.21-08-036, p. 462.

[1354] D.21-08-036, pp. 462-463.

preparedness, grid resiliency, customer savings, information exchange, and miscellaneous activities that benefit SCE customers).[1355] SCE also shared its conclusion, based on EEI's "2023 Lobbying, Advocacy, and Other Expenditures" report, that "the majority of SCE's EEI dues are going to activities that benefit ratepayers and are thus eligible for ratepayer funding, with the exception of those portions already excluded from SCE's request that are identified in the [EEI] invoice as pertaining to influencing legislation."[1356] SCE points to EEI's budget breakdown by "Business and Policy Issue" and well as by "Department" to support its claim.[1357]

SCE overlooks the fact that EEI is "the trade association that represents all U.S. investor-owned electric companies," which "provides public policy leadership, strategic business intelligence, and essential conferences and forums" for its member electric companies.[1358] If investor owned electric companies and their ratepayers had the same interests, there would be no need for ratepayer advocates. It is not self-evident that EEI's activities provide concrete benefits to ratepayers. Why should the Commission assume that SCE's ratepayers benefit from the activities of EEI's General Counsel's Office, Government Relations Department, Political & External Affairs Department, or State & Federal Regulatory Affairs Department, for example, when EEI is a utility trade association?[1359] Similarly, the Commission cannot simply assume that SCE's ratepayers benefit from EEI's advocacy related to the specific policy issues addressed by EEI, such as Fuel Diversity and Clean Energy, Grid Investment & Modernization, Finance

[1355] Ex. SCE06V08, pp. 27-34.

[1356] Ex. SCE06V08, pp. 39-40.

[1357] Ex. SCE06V08, pp. 39-40; Ex. SCE-17V06, p. 12 (citing Appendix B, EEI's 2023 Lobbying, Advocacy, and Other Expenditures Report).

[1358] Ex. SCE-17V06, Appendix B, p. B2.

[1359] *See* Ex. SCE-17V06, Appendix B, p. B4 (EEI Core Budget Expenditures by Department).

and Taxes, and Customer Solutions.[1360] The Commission has disallowed funding for utilities in these same issue areas (among others) when ratepayer advocates demonstrate that the utility has failed to demonstrate the reasonableness of its request.[1361] Given the nature of EEI, the Commission's default assumption has been, and should continue to be, that ratepayer funding for EEI dues *should be denied* "unless a utility provides sufficient evidence to establish clear ratepayer benefits."[1362] SCE's reliance on the EEI budget breakdown is misplaced.

In rebuttal testimony, SCE faults TURN for failing to propose a way to calculate the portion of EEI dues that are attributable to the NARUC categories the Commission has previously deemed improper for ratepayer recovery, which, according to SCE, leaves the EEI invoice as "the best evidence available."[1363] SCE suggests that adopting SCE's forecast, "in the absence of any reasonable alternative from intervenors, would also be consistent with what the Commission did under similar circumstances" in SDG&E's 2019 GRC, citing D.19-09-051.[1364] The Commission should dismiss these errant contentions for two reasons.

First, SCE would inappropriately shift the burden of demonstrating the amount of reasonable funding for EEI dues to TURN, when "It is SCE's burden to establish that requested funds are eligible for rate recovery."[1365] For this reason, the Commission has repeatedly directed

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[1360] *See* Ex. SCE-17V06, Appendix B, p. B3 (EEI Core Budget Expenditures by Issue Area).

[1361] *See, e.g.,* D.24-01-004 (denying SCE's application for approval of building electrification programs); D.19-05-020, pp. 370-371 (approving less funding than requested by SCE for Grid Modernization capital expenditures); D.21-10-025, pp. 27-29 (denying, among other things, SCE's requested financing order for O&M expenses and Uncollectibles); D.21-08-036, Section 19.1.1.1 (reducing funding for SCE's Billing Services).

[1362] D.21-08-036, p. 461.

[1363] Ex. SCE-17V06, pp. 13-14.

[1364] Ex. SCE-17V06, p. 14 (citing D.19-09-051, p. 583).

[1365] D.12-11-051, issued in SCE's 2012 GRC, p. 507 (addressing SCE's request for EEI dues).

SCE to establish that its GRC request excludes all 6 of the NARUC categories and emphasized that the EEI invoice is insufficient to that end, as noted above. Moreover, SCE is an EEI member and as such, has access to information from EEI that TURN does not.

Second, in D.20-07-038, the Commission modified the treatment of EEI dues in D.19-09-051. While the Commission had initially authorized SDG&E's request for EEI dues less the percentage identified on the EEI invoice as for lobbying, the Commission concluded in D.20-07-038 that this treatment was in error because the EEI invoice provided "nothing to indicate whether any other portion of SDG&E's dues was allocated for other activities we have deemed improper for ratepayer funding."[1366] The Commission accordingly modified D.19-09-051 to further limit funding for SDG&E's EEI dues.[1367]

Given SCE's showing, which fails to establish that the requested dues will not fund any activities the Commission has deemed improper for ratepayer funding, the Commission should take the same approach it took in SCE's 2021 GRC. The Commission should authorize funding for Restoration, Operations, and Crisis Management Program, plus 50% of the remainder of EEI non-charitable dues, as recommended by TURN. Based on TURN's calculation, this adjustment yields a reduction of $0.770 million to SCE's request.[1368]

[1366] D.20-07-038, p. 7.

[1367] D.20-07-038, p. 7.

[1368] Ex. TURN-11 (Defever), p. 18).

37.3.2 The Commission should disallow ratepayer funding for the California Taxpayer Association.

SCE's forecast includes $42,156 for CalTax dues.[1369] According to SCE, CalTax's "mission is to protect taxpayers from unnecessary taxes and to promote government efficiency."[1370] SCE claims that CalTax "helps SCE reduce corporate tax liability" and "allows SCE to reduce tax expenses borne by customers."[1371]

The Commission should disallow recovery of CalTax dues here for the same reason as in prior GRC decisions. In D.12-11-051, issued in SCE's 2012 GRC, the Commission noted that CalTax is "focused on tax policy, not the delivery of electrical service, and ratepayers may disagree with their views or even be adversely affected by them." [1372] The Commission disallowed funding for CalTax dues because "advancing policies of tax reduction is inherently political and ratepayers should not fund SCE's membership dues in political organizations, regardless of some attenuated potential rate benefit."[1373] Accordingly, the Commission should reduce SCE's forecast for Professional Development and Education by $42,156.

[1369] Ex. SCE-06V08 WP, p. 27. This amount excludes 14% of total dues which CalTax identified as related to lobbying. Ex. SCE-06V08, p. 34.

[1370] Ex. SCE-06V08, p. 34.

[1371] Ex. SCE-06V08, pp. 34-35.

[1372] D.12-11-051, p. 507. *See also* D.19-05-020, issued in SCE's 2018 GRC, p. 250 (disallowing funding for California Taxpayer Association, among other organizations, because "SCE has not established the ratepayer benefits of supporting these organizations.").

[1373] D.12-11-051, p. 507.

37.4 Ratemaking Cost Recovery Business Planning Element

38. RESULTS OF OPERATIONS

38.1 Results Of Operations

38.2 CPUC-Jurisdictional Revenue Requirement

38.3 GRC Ratemaking Proposals, Including Memorandum And Balancing Accounts

38.3.1 Memorandum and Balancing Accounts

38.3.1.1 The Commission Should Continue to Rein In the Reliance on Memorandum and Balancing Accounts.

TURN urges the Commission to continue here on the path from the recent PG&E GRC decision, by limiting opportunities for the utility to recover above-authorized costs and, where such an opportunity is provided, relying on an application-based reasonableness review rather than a lesser review or, as SCE has proposed in several key areas, effectively no review whatsoever.

It is more important than ever that Commission-adopted ratemaking mechanisms provide SCE with an effective cost control incentive. Similarly, where the utility is provided an opportunity to recover spending in excess of the forecast adopted here, there must be effective review processes to ensure that the cost control incentive worked. SCE's customers today already face substantial and growing affordability challenges from currently-authorized rates and the further increases likely to result from other pending proceedings. Clearly, the rate impacts will go from bad to worse with this GRC decision, with the only question being how much worse.[1374] The Commission needs to ensure that the utility's management acumen is deployed in full force to not only meet the growing and changing requirements for the scope and scale of its operations, but to do so in a least-cost manner.

The Commission has long recognized that forecast-based cost of service ratemaking serves to give "utility management an opportunity and incentive to find ways to conduct operations for less than projected."[1375] This incentive to manage costs at or below the authorized amount was recognized as essential to successful cost of service ratemaking:

> If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality.[1376]

To be clear, TURN is <u>not</u> arguing here that SCE has completely lost the economic incentive to control its costs. But the Commission should be very concerned with the severe erosion of that incentive in recent years with the growth of memorandum and balancing accounts, both in number and in the extent of utility and operations and spending now subject to those ratemaking mechanisms. If cost-of-service ratemaking is to include appropriate and meaningful incentives to ensure least-cost approaches from a utility, reliance on balancing and memorandum accounts should be more the exception, rather than the expectation.

[1374] SCE's GRC request seeks a $1.76 billion increase for 2025, followed by increases in the $593 million to $627 million range for each of the three years following. The Commission can also anticipate separate applications in the relatively near future for an AMI 2.0 project and a Next Gen ERP project, both of which are certain to have very substantial costs.

[1375] D.96-12-066 (PG&E application seeking extra-GRC costs), 1996 Cal. PUC LEXIS 1111, *5, *quoting* D.85-03-072.

[1376] *Id.*, *5-6, *quoting* D.85-03-072.

Furthermore, the Commission should recognize that the fact that memorandum or balancing account treatment was adopted in the past for a category of costs does not mean that treatment should be maintained forever for such costs. As the utility gains experience with programs and activities, its management should be able to develop forecasts of sufficient accuracy and certainty and operate subject to those forecasts. And with that experience in hand, balancing or memorandum account treatment should no longer be necessary or appropriate due to any purported difficulty of forecasting.[1377]

The prevalence of memorandum and balancing account ratemaking also undermines the transparency of the Commission's regulatory process, particularly the confidence the Commission can have in the bill impacts it uses to assess a GRC's impact on customers.[1378] Simply put, the Commission knows from experience that any estimate of the overall rate impact that is tied to the forecasts authorized in a GRC decision is likely to prove significantly understated once the above-authorized spending subject to memorandum or balancing account treatment is factored in. The difference can be quite substantial ($300 million of above-authorized spending for vegetation management in 2021 alone, for example).[1379] At the time the Commission issued the 2021 GRC decision, it calculated the overall authorized revenue requirement increase over present rates as approximately $489 million.[1380] Once the full impact

[1377] Ex. TURN-15-E2, pp. 5-6. In the recent PG&E GRC decision, the Commission replaced several key two-way balancing accounts with one-way balancing accounts in recognition of the utility's increased experience with the underlying activities. D.23-11-069, pp. 482-486, and 487-488. Similar outcomes are warranted here.

[1378] Ex. TURN-15-E2, p. 5.

[1379] The 2021 GRC decision authorized $207 million for SCE's vegetation management programs; SCE recorded $515 million for that work in 2021. Ex. SCE-02, Vol. 10, p. 4, Figure I-3.

[1380] D.21-08-036, Appendix B – CPUC RO Comparison.

of above-authorized 2021 spending in memorandum and balancing accounts is factored in, the effective increase is likely to be more than double that figure.

TURN urges the Commission to take reasonable steps to rein in the growth of reliance on memorandum and balancing accounts.[1381] It should only permit the creation of new accounts or continuation of existing accounts where the utility demonstrates that such action is required by statute or compelling circumstances. And where memorandum or balancing accounts continue to be relied upon, the Commission must ensure an opportunity for close scrutiny of the reasonableness of any above-authorized amounts before rate recovery of those amounts is permitted. To the same end, the Commission must reject SCE's proposals to either do away altogether with reasonableness reviews of above-authorized spending, or to have that review take place either via advice letters or in ERRA proceedings. Without effective review of above-authorized costs for reasonableness, the utility faces little if any cost control incentive whatsoever.

The Commission should continue the progress displayed in the recent decision on PG&E's test year 2023 GRC. There the Commission modified the balancing accounts for wildfire mitigation and vegetation management program costs from two-way balancing accounts to a one-way balancing account going forward.[1382] It also rejected a number of the "substantial and substantively significant revisions to numerous accounts" due to the need for additional time to fully review them.[1383] The decision also recognized that closing existing accounts "will

[1381] Ex. TURN-15-E2, pp. 2-6.

[1382] D.23-11-069 (PG&E TY 2023 GRC), pp. 485-486 and 487-488 (modifying the Wildfire Mitigation Balancing Account and the Vegetation Management Balancing Account to each become a one-way rather than a two-way balancing account).

[1383] D.23-11-069 (PG&E TY 2023 GRC), p. 728 and Finding of Fact 383.

promote transparency and simplicity."[1384] TURN urges the Commission to recognize that these outcomes represented progress, and the current GRC offers an opportunity to build on that progress.

38.3.1.2 The Commission Should Adopt a "Deductible" that Would Routinely Apply to New Memorandum Accounts.

In a recent decision addressing the Sempra Utilities' request for a new memorandum account that would permit recording of costs incurred due to upcoming changes in federal gas safety-related rules and regulations, the Commission authorized the new memorandum account, but subject to a deductible amount of $10 million based on the then-effective "Z-Factor allowance" for those utilities.[1385] TURN recommends that the Commission apply this approach more routinely to memorandum account requests, starting with SCE's requests in this GRC.[1386] TURN believes this approach will have a number of beneficial impacts. First, it would stem at least somewhat the erosion in forecast-based ratemaking that has occurred due to the growth in recent years of reliance on memorandum accounts seemingly every time the utility identifies a potential new cost. Second, it should counteract at least somewhat the incentive SCE faces if it is positioned to avoid bearing any "deductible" if it creates a new memorandum account rather than seeking recovery through its existing Z Factor mechanism. TURN knows of no valid policy

[1384] *Id.*, Conclusion of Law 290. The Commission also noted that the requests to close accounts in that GRC were unopposed.

[1385] D.23-05-003, Ordering Paragraph 1. The Sempra Utilities had not proposed recording of the costs subject to their respective Z factor mechanisms, and the Commission did not direct recovery through the existing mechanisms. Rather, it applied a deductible at the level adopted for the Z factor to the new memorandum account.

[1386] Ex. TURN-15-E2, pp. 6-7.

purpose served by permitting SCE to face such a deductible only when Z factor treatment is applied. The Commission should apply the deductible to all memorandum account requests.

SCE opposes the $10 million deductible, labeling it a vestige of the utility's short-lived experiment with performance-based ratemaking (PBR) that has no place in cost-based ratemaking.[1387] Missing from SCE's position is an acknowledgement that it was the utility that proposed maintaining that deductible when it returned to cost-of-service ratemaking after a six-year hiatus.[1388] The Z-factor deductible has been part of cost-of-service ratemaking since then, and SCE proposed its continuation here.[1389]

38.3.1.3 SCE Proposed Changes to Existing Balancing Accounts and Memorandum Accounts

38.3.1.3.1 Wildfire Risk Mitigation Balancing Account/Grid Hardening Balancing Account

The Commission must reject SCE's proposals to adopt lesser levels of review for greater amounts of above-authorized grid hardening spending, and instead adopt TURN's recommended modifications.

SCE currently has a Wildfire Risk Mitigation Balancing Account (WRMBA) that was authorized in its test year 2021 GRC. SCE had requested that the account cover a broad array of

[1387] Ex. SCE-18, Vol. 1, pp. 3-4.

[1388] D.04-07-022 (SCE TY 2003 GRC), p. 2 and 278-279. The Commission described how the deductible worked in the PBR context: "SCE is at risk for events that do not have a revenue requirement impact of more than $10 million, and there is a $10 million 'deductible' applied on a one-time basis to the first year's revenue requirement associated with any approved Z-Factors." After crediting SCE with the proposal to continue the Z-factor and the associated deductible as part of the post-test year ratemaking going forward, the Commission stated it was reasonable to do so "with the return to more conventional cost-of-service ratemaking." *Id.*, pp. 278-279.

[1389] Ex. SCE-07, Vol. 1, p. 34, fn. 46.

wildfire mitigation programs, with the review of above-authorized spending to occur in the utility's ERRA proceeding. As adopted by the Commission, the balancing account focused on a single program (the Wildfire Covered Conductor Program), with an application required for recovery of costs above 110% of the GRC-authorized amount.[1390]

Here, SCE proposes to expand the scope of its existing WRMBA to include not just WCCP-related expenditures, but also costs of its Targeted Undergrounding Program (TUG), Rapid Earth Fault Current Limited (REFCL) activities, and Long Span Initiative (LSI) activities. SCE also proposes renaming the account as the Grid Hardening Balancing Account (GHBA) to reflect this broader scope of activities. For rate recovery issues, SCE's primary recommendation is to <u>eliminate</u> the reasonableness review of any amount of above-authorized spending. If the Commission feels some level of review is necessary, SCE proposes an increased threshold of 125%.[1391]

TURN's testimony recommended the Commission deny SCE's proposed modifications to the ratemaking associated with the WRMBA. TURN contended the utility's primary proposal to eliminate altogether reasonableness review of above-authorized spending is not to be taken seriously.[1392] It is an extreme proposal: If SCE's recorded spending was twice the amount that had been authorized, there still would be no reasonableness review.[1393] As TURN explained, the same would be true even if the above-authorized spending had been caused by clear instances of imprudent or unreasonable action or inaction on the part of the utility – no reasonableness

[1390] D.21-08-036 (SCE TY 2021 GRC), pp. 247-250.

[1391] Ex. SCE-07, Vol. 1, pp. 30-32.

[1392] Ex. TURN-15-E2, pp. 7-9.

[1393] *Id.*, p. 8, citing Attachment 2 (SCE Response to TURN DR 48-1.a.).

review, just rate recovery.[1394] TURN submits that such an approach cannot possibly satisfy the "just and reasonable" standard of Public Utilities Code 451. TURN also calls for rejection of SCE's alternative proposal to increase the threshold requiring a reasonableness showing from 110% to 125%. Instead, the Commission should adopt ratemaking modifications similar to those adopted for PG&E's wildfire mitigation programs in the test year 2023 GRC decision. As noted earlier, there the Commission authorized continuation of PG&E's WMBA, but as a one-way balancing account.[1395]

SCE's direct testimony was served in mid-2023. In November 2023, the Commission issued its decision in PG&E's test year 2023 GRC, where it addressed that utility's proposals regarding its existing Wildfire Mitigation Balancing Account (WMBA). Instead of increasing from 115% to 125% the threshold above which reasonableness reviews were required of above-authorized spending as the utility had requested, the Commission revised the WMBA so it became a one-way balancing account (thereby eliminating the need for a threshold figure of any amount).[1396]

SCE's proposed modifications run counter to the degree of utility discretion and control regarding the costs that would be recorded in the new account. The scope and scale of the grid hardening programs, their design, implementation and ongoing operation – every element is subject to management determinations and decisions. SCE is often heard to claim that balancing or memorandum account treatment is necessary due to costs being outside of its control. But for

[1394] *Id.*, p. 8.

[1395] As explained further in the Grid Hardening section of this brief (Section 15.2), TURN also recommends that the one-way balancing account for all grid hardening expenditures include a separate one-way sub-account with specific provisions applicable to undergrounding expenditures.

[1396] D.23-11-069, pp. 482-486.

its grid hardening activities (like its vegetation management activities), that trope should not get the utility very far. And when there is such a degree of utility influence and control over the amount of costs ultimately recorded, if the Commission chooses to permit an opportunity for rate recovery of above-authorized costs, there needs to be a rigorous reasonableness review showing required.

SCE's rebuttal testimony does not shore up its inadequate showing. In an attempt to be afforded treatment radically different from that adopted for PG&E just a few months ago, the utility cites distinctions that should not make a difference in this context.[1397] These are two regulated electric utilities operating in the same state, subject to the same laws and regulations, and operating wildfire mitigation programs of a very similar general nature. More galling is SCE's suggestion that its proposed two-way balancing account "mitigates risk for customers and investors."[1398] Under SCE's primary proposal, it would be permitted to spend uncapped amounts in excess of the forecast found reasonable based on the record of this GRC, and to recover those amounts subject to no reasonableness review. What risk is being mitigated for SCE's customers under that proposal?

38.3.1.3.2 Vegetation Management Balancing Account

As with the GHBA, the Commission must reject SCE's proposals to adopt lesser levels of review for greater amounts of above-authorized spending, and instead adopt TURN's recommended modifications.

[1397] Ex. SCE-18, Vol. 1, p. 14.

[1398] *Id.*, p. 17.

In SCE's test year 2021 GRC, the utility's proposed ratemaking for its Vegetation Management Balancing Account (VMBA) was to have review of any above-authorized amounts recorded in the account occur in SCE's annual ERRA cost review proceeding. As a fallback position, SCE proposed a "soft cap" of 120%, with the reasonableness review of costs above that "cap" occurring through a Tier 3 Advice Letter.[1399] The Commission adopted a two-way balancing account as SCE requested, but rate recovery of costs in excess of 115% of the authorized amount would require a reasonableness review application. The Commission described its approach as "generally consistent" with the outcome adopted in the TY 2020 GRC of PG&E.[1400]

Key elements of SCE's VMBA ratemaking proposal in this GRC are very similar to those of its proposal for the WRMBA/GHBA, discussed above. Most egregious is SCE's primary recommendation to <u>eliminate</u> the reasonableness review of any amount of above-authorized spending.[1401] As explained in the previous section, the Commission should deny SCE's proposal to eliminate altogether reasonableness review of above-authorized spending. Again, under this new proposal, SCE could spend twice the amount authorized and there would still be no reasonableness review of the above-authorized spending.[1402] The Commission should also reject SCE's alternative proposal to increase the threshold requiring a reasonableness showing from 115% to 125%.[1403] The utility has not demonstrated that such a change would do anything other

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[1399] Ex. TURN-15-E2, p. 9, *citing* SCE's 2021 GRC testimony, Ex. SCE-18, Vol. 1, p. 17.

[1400] D.21-08-036, p. 186.

[1401] Ex. SCE-07, Vol. 1, pp. 32-33.

[1402] Ex. TURN-15-E2, p. 10, *citing* Attachment 3 (SCE Response to TURN DR 48-4.a.).

[1403] Ex. SCE-07, Vol. 1, pp. 32-33.

than increase the amount of potential costs that it could incur without ever having those costs subject to a meaningful determination of reasonableness.[1404] Instead, the Commission should modify SCE's VMBA so that it is a one-way balancing account, consistent with the approach adopted for PG&E's vegetation management mitigation programs in the test year 2023 GRC decision.[1405]

SCE's rebuttal testimony does little beyond confirming how extreme and poorly supported its VMBA ratemaking proposal is. For example, SCE claims that a two-way balancing account is necessary because there is inherent variablility associated with vegetation management work, variability that is "in part due to exogenous factors."[1406] Even for costs due to truly exogenous factors, the utility will have some ability to control costs; a reasonableness review serves as an opportunity to ensure that the utility did, in fact, take appropriate cost minimization steps. And the obvious inference from SCE's description is that the purported variability is in part due to factors that are <u>not</u> exogenous, but rather within the utility's control or influence. Again, all the more reason why an effective reasonableness review showing must be required prior to recovery of any above-authorized costs. Furthermore, as the Commission recognized in the case of PG&E, the ratemaking treatment for vegetation management expenses should reflect the fact that the utility is "now well-experienced at an increased level of vegetation management" as compared to the level of activities and spending prior to the focus on wildfire mitigation work.[1407]

[1404] Ex. TURN-15-E2, pp. 10-11.

[1405] D.23-11-069, pp. 487-488.

[1406] Ex. SCE-18, Vol. 1, p. 20.

[1407] D.23-11-069, p. 487 and Finding of Fact 233.

38.3.1.3.3 Risk Management Balancing Account

In D.23-05-013, the Commission adopted an agreement to implement a self-insurance alternative for SCE's wildfire liability insurance coverage. The settlement included a provision committing SCE to modify the Risk Management Balancing Account (RMBA) as necessary to shift to reliance on self-insurance and otherwise support the settlement. SCE has subsequently made such modifications to the RMBA. Here, SCE proposes to continue the RMBA as modified pursuant to D.23-05-013.[1408] TURN agrees with and supports this proposal. TURN also anticipates SCE will, in consultation with the other settling parties, present the Commission with proposed further modifications of the RMBA as needed to implement the final decision granting the motion to extend the self-insurance framework through the 2025 GRC period.[1409]

38.3.1.3.4 Electric Vehicle Infrastructure Memorandum Account

SCE established a new Electric Vehicle Infrastructure Memorandum Account to record certain electric vehicle infrastructure related costs during the period from 2021 through 2024. Pursuant to Section 740.19(c) of the Public Utilities Code, costs incurred between January 1, 2021 and the utility's next GRC's implementation date are to be tracked in a memorandum account and "recovered, subject to a reasonableness review, in the decision adopting the next general rate case revenue requirement" for the utility. SCE contends that a "timing issue" means it will not be able to obtain a reasonableness review through this TY 2025 GRC for the amounts

[1408] Ex. SCE-07, Vol. 1, p. 34.

[1409] As described in Section 29.1, above, the Commission recently issued a proposed decision that would grant the unopposed motion.

it expects to spend in 2023 and 2024. Therefore, SCE proposes that the reasonableness review take place in the form of a Tier 3 advice letter, rather than in an application.[1410]

The Commission should reject SCE's proposal to have the reasonableness review of these costs in a Tier 3 advice letter, and instead continue to require that the review take place in an application proceeding. The statutory language is very specific; a reasonableness review is required, and it is expected to take place in the utility's next GRC. The Commission might have discretion to direct that the reasonableness review take place in a different application-based proceeding consistent with performing a reasonableness review. But the plain language of the statute does not contemplate the review taking place through the advice letter process. And it certainly would not permit the review to take place in an ERRA proceeding which, as the Commission told SCE in its 2021 GRC, is not a forum that constitutes a reasonableness review.[1411]

Even if the Commission had discretion under the statute to substitute a Tier 3 advice letter for the required review in a GRC, it should reject SCE's proposal in recognition of the limitations of the advice letter process given the more compressed schedule, the lack of testimony, and no opportunity for hearings on disputed factual issues.[1412] TURN's testimony had explained that SCE's preliminary cost figures suggested a total cost figure of approximately

[1410] Ex. SCE-07, Vol. 1, p. 54.

[1411] SCE's rebuttal testimony suggests that if an advice letter is not an acceptable substitute, perhaps the ERRA application would be. Ex. SCE-18, Vol. 1, p. 27. In D.21-08-036, the Commission stated, "An annual compliance review … in the ERRA proceeding, as proposed by SCE, would not entail a reasonableness review that considers such information [regarding the specific causes of above-authorized recorded amounts]." D.21-08-036, p. 404.

[1412] Ex. TURN-15-E2, p. 12.

$45 million.[1413] SCE's rebuttal testimony argued that if one only considered the projects for which it has cost estimates at this time (77 of the 255 EVIMA-eligible projects), the requested review would likely involve $15.8 million.[1414] But the cited data request response does not reflect any any costs for the remaining EVIMA-eligible projects, all of which are "in flight" according to the utility. It merely says SCE only has cost estimates for approximately one third of them at this time.[1415] Multiplying SCE's partial figure by three gets the Commission to TURN's estimated figure.

38.3.1.3.5 Z-Factor Memorandum Account

The Commission should reject SCE's proposal to extend its Z-Factor mechanism to the 2025 test year, and instead limit its availability to the PTYR period for this GRC cycle, as has been the case since the Z-Factor mechanism was first addressed in an SCE GRC application.[1416] While SCE is correct that the Commission adopted a similar extension of the Sempra utilities' Z-Factor mechanism in their test year 2019 GRC, in doing so the agency specifically noted that it had not been presented with "any rationale" that might support limiting the Z-Factor mechanism to attrition years.[1417] In the recent TY 2023 GRC decision for PG&E, the Commission provided just such a rationale:

> Because the purpose of a general rate case is to provide a fairly precise forecast of the test year, the Commission does not adopt PG&E's proposal to apply the Z-Factor mechanism to the test year, 2023.[1418]

[1413] *Id.*, and Attachment 4 (SCE Response to TURN DR 101-1).

[1414] Ex. SCE-18, Vol. 1, p. 27.

[1415] *Id.*, Appendix A, p. A-2 (SCE Response to TURN DR 101, Q. 1).

[1416] Ex. TURN-15-E2 , p. 13.

[1417] D.19-09-051, p. 712.

[1418] D.23-11-069, p. 717.

This fundamental purpose of a GRC is the same for SCE as it is for PG&E, and warrants adoption of the same ratemaking approach as the Commission adopted in D.23-11-069.

The Commission should also modify SCE's Z-Factor mechanism to require an application, rather than an advice letter, to seek recovery of costs tracked in its Z-Factor Memorandum Account. In the TY 2023 GRC decision, the Commission rejected PG&E's proposal to implement Z-Factor-related revenue requirement changes via advice letter, rather than application, finding "advice letters address ministerial matters and … application of the Z-Factor mechanism is not simply ministerial…."[1419] Similar logic should be applied to SCE going forward.

38.3.1.4 Proposed New Balancing Account – General Liability Insurance Balancing Account (GLIBA)

TURN's prepared testimony recommended rejection of SCE's proposal for a new General Liability Insurance Balancing Account (GLIBA).[1420] As discussed in Section 29.2, above, TURN has joined SCE and Cal Advocates in presenting a stipulation that, if adopted, would resolve the disputed forecast and ratemaking issues associated with the utility's general liability and property insurance. One element of the proposed stipulation would permit SCE to establish a new balancing account covering both general liability and property insurance forecasts and expenses, to be designated the General Liability & Property Insurance Balancing Account (GL&PBA).[1421] Again, though TURN has called on the Commission to reduce its

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[1419] *Id.*

[1420] Ex. TURN-15-E2, pp. 14-16.

[1421] Ex. SCE-34 (Stipulation of TURN, Cal Advocates and SCE on Non-Wildfire Insurance).

reliance on balancing and memorandum accounts as a general matter, TURN believes the new account is acceptable under the circumstances here and as part of the several compromises reflected in the stipulation.

38.3.1.5 New Memorandum Account Proposals

38.3.1.5.1 Next Gen ERP SAP Memorandum Account

SCE proposes to create a new NextGen ERP SAP Memorandum Account (NGESMA), with a January 1, 2024 effective date, to record the revenue requirements associated with O&M expenses and capital expenditures for activities related to the implementation phase of the NextGen ERP project.[1422] The Commission should deny this request for a new memorandum account, based on the record evidence that any costs recorded before the end of 2024 should be deemed costs covered by the 2021 GRC revenue requirement, and due to SCE's failure to establish that the costs at issue are sufficiently substantial to warrant memorandum account treatment.

SCE's proposed NextGen ERP project is discussed in the utility's capitalized software testimony in this GRC.[1423] In SCE's test year 2021 GRC, the utility presented a "portfolio-based forecast" for its 2021-2023 capitalized software spending, without specified capital projects.[1424] Approximately 55% of the forecast was allocated to the utility's "Enterprise Support" group, covering a broad array of enterprise operations.

> Future spend in these areas supports almost all business outcomes across SCE and drives operational and service excellence across the enterprise.

[1422] Ex. SCE-07, Vol. 1, p. 45.

[1423] Ex. SCE-07, Vol. 1, p. 45, referring to Ex. SCE-06, Vol. 2.

[1424] Ex. TURN-104 (SCE testimony from test year 2021 GRC), p. 169.

> Some of the key solutions being planned are improvements to our core, foundational SAP systems….[1425]

SCE's core business data and functions all run or flow through SAP.[1426] In its test year 2021 GRC testimony, SCE stated "the current [SAP Enterprise Resource Planning] system … is due to become obsolete in 2025."[1427] And in the testimony for the instant GRC, SCE states that it began planning in 2020 for the transformation from the current system to the "NextGen ERP" system.[1428] Given these circumstances, the Commission should not permit SCE a new memorandum account, but instead should deem the costs through the end of 2024 as subject to the currently authorized GRC revenue requirement. With its portfolio-based approach for 2021-2023 (and, 2024, consistent with the extension of the 2021 GRC cycle), SCE can identify few if any specific projects that were contemplated for 2024. And given the critical role SCE describes its SAP ERP system playing in key areas of its operations, and the utility's earlier recognition of the upcoming need for the work, it is reasonable to treat it as covered by the existing GRC revenue requirement.

The Commission should also deny SCE's request for a NGESMA because the capital costs associated with the project are highly unlikely to close to plant separately from the overall project costs, and the overall project costs will be addressed in an upcoming application. Thus,

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[1425] Ex. TURN-104, pp. 177-178.

[1426] SCE Motion Seeking to Establish Three Memorandum Accounts (May 15, 2023), p. 5.

[1427] Ex. SCE-06, Vol. 1, Pt 2A from the test year 2021 GRC, p. 71. An excerpt of this testimony was included as an attachment to TURN's response to SCE's motion seeking new memorandum accounts (May 30, 2023).

[1428] SCE-06, Vol. 2 (Enterprise Technology – OU Capitalized Software), p. 73.

the new memorandum account seems to be addressing a non-existent cost recovery timing risk for capital costs.[1429]

Prior to TURN's direct testimony, SCE had only referred to capital expenditures associated with the implementation phase of the NextGen ERP project. Therefore, TURN's testimony only addressed the expected capital expenditures.[1430] SCE's rebuttal testimony claims the utility has subsequently become aware of "a potential likelihood" of $2-4 million it "could incur" in Implementation O&M costs in 2024.[1431] TURN submits this late-breaking development should not alter the outcome, and the memorandum account request should still be denied. SCE has not demonstrated that this level of O&M funding is significant or substantial enough to warrant establishment of a new memorandum account.

If the Commission chooses to authorize this new memorandum account as of January 1, 2024, it should be subject to a deductible of $10 million, consistent with TURN's earlier-described proposal to routinely apply a deductible in the amount of the Z factor deductible in effect at the relevant time, here 2024.

38.3.1.5.2 Advanced Metering Infrastructure 2.0 Memorandum Account

The Commission should deny SCE's request to establish a new Advanced Metering Infrastructure 2.0 Memorandum Account (AMIMA), and instead treat any O&M expenses associated with the pre-deployment base-level planning costs for a new AMI project as subsumed within the then-authorized 2021 GRC revenue requirement.

[1429] Ex. TURN-15-E2, pp. 16-17.

[1430] *Id.*, p. 17.

[1431] Ex. SCE-17, Vol. 1, p. 89.

SCE is in the process of developing a new Advanced Metering Infrastructure (AMI) 2.0 project for providing metering services to its customers, and plans to file a stand-alone application "in the 2025 time frame" with a funding request for full AMI deployment.[1432] The utility has included "base-level planning costs" from 2023 through 2027 in its GRC testimony. If the new AMIMA is approved, the utility would use it to record the "pre-Test Year O&M expenses associated with the planning costs."[1433] SCE anticipates incurring $4.432 million of such O&M expenses in 2023, and $0.585 million in 2024.[1434]

TURN submit that there are several reasons for denying this memorandum account request. First, the "base-level planning costs" associated with ensuring SCE's customers receive adequate metering services should be deemed subsumed within the authorized 2021 GRC revenue requirement. Providing metering services to its customers is a fundamental part of SCE's operations. Costs incurred during the 2021 GRC period and associated with the replacement of existing meters, whether on a piecemeal basis or as the initial planning costs toward a wholesale changeout of equipment, should be treated as 2021 GRC-covered costs, even where the utility ostensibly chose not to include a forecast in the earlier GRC showing.[1435] In its motion seeking establishment of the memorandum accounts, SCE asserted that it did not include this subset of O&M costs in its 2021 GRC "given uncertainty in the magnitude, scope, and

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[1432] Ex. SCE-07, Vol 1, p. 46. The associated "base-level" capital expenditures in those years are included for review and recovery in SCE's GRC request, and would not be included in the AMIMA.

[1433] SCE Motion Seeking to Establish Three Memorandum Accounts (May 15, 2023), p. 3.

[1434] Ex. SCE-07, Vol 1, p. 46. The associated "base-level" capital expenditures in those years are included for review and recovery in SCE's GRC request, and would not be included in the AMIMA.

[1435] Ex. TURN-15-E2, pp. 18-19.

timing for these costs at the time that application was filed."[1436] The Commission considered and rejected a similar explanation from SoCalGas when it denied that utility's request for a new memorandum account under similar circumstances.[1437] SoCalGas had argued that the pre-construction costs associated with a major pipeline replacement project "were not ripe for inclusion" in its prior GRC.[1438] But the Commission relied more on SoCalGas's failure to present any argument or evidence that "it was prohibited, precluded, or otherwise incapable of including those costs in its 2016 GRC."[1439] Similarly, SCE has not presented any such evidence here.

Second, the record of the test year 2021 GRC proceeding establishes the appropriateness of treating the AMI 2.0 initial planning costs as covered by the authorized GRC revenue requirement through 2024. The GRC decision quotes SCE's testimony in describing the work done under the heading "Meter Activities," including "guards against the issues caused by technology obsolescence."[1440] In that testimony, SCE also described its "need to maintain its SmartConnect system by addressing the challenges created by the obsolescence of our existing metering system."[1441] In the 2025 GRC, SCE initially described its proposed AMI 2.0 deployment as needed in order to address approaching technology obsolescence,[1442] but seemed to attempt to reverse course in its rebuttal testimony, asserting that the costs at issue "have

[1436] SCE Motion for a Ruling Authorizing Establishment of Three Memorandum Accounts to Track Certain Costs Beginning in 2023 and 2024 (May 15, 2023), p. 9.

[1437] D.18-04-012, p. 10.

[1438] *Id.*, p. 11.

[1439] *Id.*

[1440] D.21-08-036, p. 62, citing TY 2021 GRC Ex. SCE-02, Vol. 1, Pt. 3, p. 4.

[1441] Ex. TURN-15-E2, pp. 18-19, citing Attachment 7 (TY 2021 GRC Ex. SCE-02, Vol. 1, Pt. 3, p. 26).

[1442] Ex. SCE-02, Vol. 3, pp. 31-32.

nothing to do with … addressing obsolescence issues associated with the existing meter fleet."[1443] TURN submits that SCE had it right the first time, and therefore the Commission should reasonably treat the AMI 2.0 initial planning costs for 2023 and 2024 as subsumed in the then-effective GRC revenue requirement.

Third, SCE has failed to establish that the approximately $5 million of O&M expense is a substantial enough amount under the circumstances to warrant establishment of a new memorandum account. SCE forecasted $4.432 million and $0.585 million as the relevant O&M expenses in 2023 and 2024, respectively.[1444] This two-year total of approximately $5 million compares to SCE's forecasted two-year total net operating revenue of approximately $5.5 billion.[1445] The utility has failed to establish that $5 million is an amount that warrants establishment of a new memorandum account.[1446]

If the Commission chooses to authorize this new memorandum account, it should be subject to a deductible of $10 million, consistent with TURN's earlier-described proposal to routinely apply a deductible in the amount of the Z factor deductible in effect at the relevant time, here in 2023 and 2024.

[1443] Ex. SCE-18, Vol. 1, p. 33.

[1444] Ex. SCE-02, Vol. 3, pp. 38 and 40.

[1445] Ex. SCE-18, Vol. 1, Appendix B, p. B9.

[1446] While SCE's rebuttal testimony argues that TURN presented no evidence that $5 million is not a substantial amount under the circumstances (*Id.*, p. 34), the burden of proof is on the utility to establish that it is.

38.3.1.5.3 Cybersecurity Compliance Memorandum Account

The Commission should deny SCE's request for a new Cybersecurity Compliance Memorandum Account (CCMA). As originally proposed, the CCMA was explained as being necessary given the "variety of emerging mandatory cybersecurity standards that are at various stages of development and that would require additional investment to comply with."[1447] SCE originally sought to establish the CCMA with an effective date of May 12, 2023, but when no incremental costs of new cybersecurity regulations were recorded in 2023 and no "significant" amounts were expected for 2024, SCE modified its proposal and now seeks a January 1, 2025 effective date for the CCMA.[1448]

TURN continues to oppose establishment of the new CCMA, even with a January 1, 2025 effective date. TURN understands SCE's contention that it has not included in its test year 2025 forecast costs associated with compliance with the "CMMC 2.0," and that the utility expects to incur "potentially significant" implementation costs at some point during the 2025 GRC cycle.[1449] Nonetheless, denial of the memorandum account request is necessary to achieve fundamental fairness. In SCE's 2021 GRC, the Commission authorized Cybersecurity Delivery O&M expenses of $23.6 million for 2021; the utility recorded $18.8 million that year, a difference of $4.8 million.[1450] The recorded figure for 2022 was also below the GRC-authorized

[1447] Ex. SCE-07, Vol. 1, p. 47, largely repeating the assertion at Ex. SCE-04, Vol. 3, p. 18, and at *SCE Motion for a Ruling Authorizing SCE to Establish Three Memorandum Accounts to Track Certain Costs Beginning in 2023 and 2024* (May 15, 2023), p. 4.

[1448] Ex. SCE-18, Vol. 1, p. 39-40.

[1449] Ex. SCE-18, Vol. 1, p. 41.

[1450] Ex. SCE-4, Vol. 3, p. 34, Figure II-7.

amount.[1451] And the Commission authorized capital expenditures of $63.8 million for 2021; the utility recorded $53.7 million, a $10.1 million difference.[1452] SCE should not be permitted to benefit from the below-authorized cybersecurity spending it recorded in 2021 and 2022, but then obtain memorandum account protection against the prospect that it might record above-authorized costs during the 2025 GRC cycle. The Commission should deny the requested CCMA.

If the Commission chooses to authorize this new memorandum account, it should be subject to a deductible of $10 million, consistent with TURN's earlier-described proposal to routinely apply a deductible in the amount of the Z factor deductible in effect at the relevant time.

38.3.1.5.4 Historic Sporting Events Cost Tracking Memorandum Account

SCE seeks to establish a new Historic Sporting Events Cost Tracking Memorandum Account (HSECTMA) in which it would record costs and services "impacted" by the 2028 Summer Olympics and the 2026 World Cup. The utility suggests the recent Super Bowl serves as a rough indication of the order of magnitude of costs it can expect to incur due to these upcoming events.[1453] However, the 2022 Super Bowl costs were so insignificant that SCE did not bother tracking them in the absence of a cost recovery mechanism.[1454] TURN submits that if

[1451] 2022 recorded spending was approximately $19.9 million. Ex. SCE-04, Vol. 3 WP, p. 20.

[1452] Ex. SCE-4, Vol. 3, p. 35, Figure II-8.

[1453] Ex. SCE-07, Vol. 1, p. 47. ["The anticipated (but yet unknown) order of magnitude is in the same range as the Super Bowl."]

[1454] When TURN asked for the amount of incremental costs SCE recorded due to the 2022 Super Bowl, the utility said that though it incurred costs, it could provide no quantification because there was no cost recovery mechanism in place. Ex. , p. 22, citing Attachment 10 (SCE Response to TURN DR 61-2.a.i).

the utility expects the costs of the upcoming events to be at a similar level as the 2022 Super Bowl, the Commission should conclude the costs are unlikely to be substantial enough to warrant creation of yet another memorandum account.

SCE also suggests that having its customers bear all incremental costs associated with addressing the energy needs of these sporting events would "align with … the expectation that all supporting institutions will be able to deliver services necessary to support these events even if these services are beyond what is typically provided."[1455] The source and the basis for this "expectation" are not clear in SCE's testimony. If SCE, as a supporting institution, wishes to subsidize the 2028 Summer Olympics or the 2026 World Cup, TURN is not aware of any restriction on its ability to use shareholder funds for that purpose. However, SCE's customers should not be treated as a "supporting institution" for such purposes, and the associated costs should not be recovered in rates.[1456]

TURN recommends that the Commission deny SCE's request for the HSECTMA at this time. If the Commission chooses to authorize this new memorandum account, it should be subject to a deductible of $10 million, consistent with TURN's earlier-described proposal to routinely apply a deductible in the amount of the Z factor deductible in effect at the relevant time.

[1455] Ex. SCE-07, Vol. 1, p. 47.

[1456] Ex. TURN-15-E2, p. 22.

38.3.1.6 Request for Recovery of Existing Memorandum Account Balances

38.3.1.6.1 Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA)

SCE's direct testimony explains that in its 2021 GRC, the Commission authorized the Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA) to track recorded costs in excess of the authorized amounts in that decision, with an opportunity to recover the recorded costs in its next GRC. SCE originally sought recovery here of the incremental costs recorded in the account, but merely provided a list of the recorded amounts, without any showing that might support a determination of reasonableness.[1457] TURN opposed such recovery based on the inadequacy of the utility's demonstration of reasonableness.[1458] In its rebuttal testimony, SCE withdrew its request because it no longer anticipated it would record costs of any amount to the account before the end of 2024.[1459]

38.3.1.6.2 Service Center Modernization Projects Memorandum Account (SCMPMA)

The Commission should determine that SCE has failed to adequately establish the reasonableness of the amounts recorded in the Service Center Modernization Projects Memorandum Account (SCPMA) for projects in service before the end of 2024, and therefore deny the utility's request for rate recovery of any portion of the associated costs.

1457 Ex. SCE-04, Vol. 1, pp. 49-50 and Table II-9.

1458 Ex. TURN-15-E2, p. 23.

1459 Ex. SCE-18, Vol. 1 p. 43.

In SCE's 2018 GRC the Commission agreed with a range of TURN criticisms regarding the evolution of and support for the utility's cost forecasts for service center modernization projects.[1460] The decision directed SCE to complete the projects identified in that GRC's testimony with the hope that such completion would be "within its forecasted budgets."[1461] In addition, the Commission required establishment of a new memorandum account for recording the costs of six specified projects, with a future determination of "whether the expenditures recorded from January 1, 2018 … onward should be recovered in rates."[1462] The Service Center Modernization Projects Memorandum Account (SCMPMA) was initially created to record the costs of the six projects, and in the 2021 GRC decision was expanded to also include costs for the Santa Barbara Service Center project.[1463]

SCE now expects most but not all of the identified projects to be completed and in service by the end of 2024. The original estimate of $24.291 million of revenue requirement through the end of 2024 was updated to $46.622 million in SCE's update testimony. SCE seeks authority to recover that amount upon issuance of a final decision here.[1464]

The Commission should deny SCE's request. SCE has failed to present the type of showing that might establish the reasonableness of the capital expenditures underlying the revenue requirement figures it now seeks to recover in rates. The utility's testimony in support of recovery of the SCMPMA amounts cross-referenced discussion of these projects in its

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[1460] D.19-05-020 (SCE TY 2018 GRC), pp. 200-208.

[1461] *Id.*, p. 202.

[1462] *Id.*, p. 203.

[1463] Ex. SCE-07, Vol. 1, pp. 60-61.

[1464] Ex. SCE-40, p. 16.

Enterprise Operations testimony.[1465] When TURN's direct testimony challenged the sufficiency of that showing, SCE's rebuttal assured the Commission that if it looked at the Enterprise Operations testimony it would find "detailed explanations of the reasons for the variances" between the actual incurred costs and the forecasts originally presented in the 2018 GRC.[1466]

The information in the Enterprise Operations testimony does not constitute an adequate demonstration of the reasonableness of the recorded amounts for each project. Rather than containing any "detailed explanations" of the cost variances, the material was more of an annotated invoice, listing for each project broad areas of costs and abbreviated statements of influencing factors.[1467] For example, consider the testimony's discussion of the Bishop Service Center Modernization project. SCE provides a bullet point level description of the scope of work completed as of the end of 2022 for the project, and of changes to the original scope of the project.[1468] It then presents a graph showing $26.174 million as the 2018 request for the project, and indicating changes in four broad categories that led to the amount recorded through 2022, as well as an additional increment "forecast through completion."[1469] This is followed by six bullet points identifying issues that resulted in unanticipated cost increases.[1470] The testimony included a similar discussion of the other projects with costs recorded in the SCMPMA.[1471] Neither the workpapers supporting the Enterprise Operations testimony nor the material in SCE's 2021 GRC

[1465] Ex. SCE-07, Vol. 1, p. 62.

[1466] Ex. SCE-18, Vol. 1, p. 48.

[1467] Ex. SCE-06, Vol. 7, pp. 16-36.

[1468] *Id*, pp. 17-18; Neal, SCE, 5 RT 564, l. 17 to 565, l. 7.

[1469] *Id.*, p. 19, Figure II-5; Neal, SCE, 5 RT 565, l. 8 to 567, l. 3. The $26.174 million figure listed as the 2018 request for this project seems incorrect, as the figure from D.19-05-020 is $20.054 million (p. 210).

[1470] *Id.*, pp. 19-20; Neal, SCE, 5 RT 567, ll. 10-13.

[1471] Neal, SCE, 5 RT 567, ll. 14-19.

discussing costs recorded in the SCMPMA provided any further information that might support a determination of cost reasonableness.[1472] There is nothing that might indicate SCE management awareness of the growing costs for these projects, or any actions taken to try to control those costs. Based on the inadequacy of the utility's reasonableness showing in support of the costs recorded in the SCMPMA, the Commission must deny rate recovery.

38.3.1.7 Wildfire Mitigation Plan Memorandum Account – The Commission Must Reject SCE's Attempt to Undo The 2021 GRC Denial of Rate Recovery for Fusing Mitigation Costs.

The Commission should deny SCE's request to recover approximately $18.4 million as the December 31, 2024 revenue requirement related to the 2020 fusing mitigation capital costs.[1473] for which the Track 3 decision in the 2021 GRC denied rate recovery.

In SCE's 2021 GRC, the Commission denied SCE's request for rate recovery of certain capital costs associated with the utility's fusing mitigation program, based on its finding that SCE had failed to meet its burden of demonstrating the costs were reasonable and should be recovered from the utility's customers.[1474] In this GRC, SCE attempts to reverse the earlier decision's outcome. SCE apparently believes it is entitled to such a "second bite at the apple" because the Commission did not use the specific word "disallow" in describing its earlier denial of rate recovery, and because the costs had originally been recorded in a memorandum account.[1475]

[1472] Neal, SCE, 5 RT 568, l. 2 to 569, l. 18; Ex. TURN-101 (Excerpt of SCE TY 2021 GRC testimony).
[1473] Ex. SCE-40 (Update Testimony), p. 19.
[1474] D.22-06-032, p. 32.
[1475] Ex. SCE-04, Vol. 5, Pt. 2, pp. 114-115; Ex. SCE-07, Vol. 1, pp. 77-78.

The Commission must reject SCE's request for several reasons. First, it is inconsistent with the Track 3 decision, which gives no indication of the Commission intending to permit SCE a second opportunity to establish the reasonableness of the costs for which rate recovery was denied. SCE had sought a determination of reasonableness for $24.6 million of incremental "fusing mitigation" capital expenditures.[1476] Instead, the Commission found "that SCE has failed to meet its burden of demonstrating" that the incremental capital costs associated with its fusing mitigation program were reasonable and should be recovered from ratepayers.[1477] Nothing in the decision suggests the Commission contemplated SCE having an opportunity to recover in this test year 2025 GRC any costs associated with the amount for which rate recovery was denied in the 2021 GRC.

Remarkably, SCE suggests reading the Track 3 decision as if it "did not disallow SCE's fusing mitigation program cost recovery amount, much less subject the capital costs to a permanent disallowance."[1478] While it is true that the Commission did not use the word "disallow" in its discussion of this cost recovery request, the language it did use leaves no doubt that it intended to deny rate recovery of at least some if not all of the costs. SCE here proposes an approach by which it would achieve rate recovery of all costs.

[1476] The Track 3 decision describes the fusing mitigation work as covered by the GSRP settlement. *Id.*, p. 28. It is not clear from the decision whether the incremental fusing mitigation capital expenditures or the associated revenue requirement was originally recorded in the GSRPBA/MA, or in the WMPMA. SCE contends in the present GRC that it "is currently recording the capital-related revenue requirement associated with these incremental fusing mitigation capital costs in its [WMPMA]." Ex. SCE-07, Vol. 1, p. 77.

[1477] *Id.*, pp. 32-33. The Commission also noted that some of the costs for installation of the potentially defective fuses were already included in rates, and there was the possibility that SCE would receive some financial recovery from the fusing manufacturer. Therefore, the Track 3 decision called for a potential adjustment in this 2025 GRC to ensure that, "[t]o the extent ratepayers have funded some of these fuses, ratepayers should be credited their fair share of any recovery from the manufacturer or supplier." *Id.*

[1478] Ex. SCE-04, Vol. 5, Part 2, pp. 114-115.

Which leads to the second reason the Commission should deny SCE's rate recovery request; it relies upon an apparent misuse of the memorandum account process. SCE's testimony acknowledges there would be a "retroactive ratemaking issue" but for the fact that the costs in question are currently recorded in a memorandum account.[1479] But the Commission has to ask why these costs were still recorded in a memorandum account after the Track 3 decision denied rate recovery. And it should be very concerned with the prospect that SCE is using the memorandum account ratemaking device to attempt to reverse previously adopted denials of rate recovery. Frankly, it never would have dawned on TURN that a rate recovery denial as clear as the one adopted in the Track 3 decision might have to be accompanied by a Commission directive to SCE to remove the associated costs from any memorandum or balancing account. Yet in the face of that rate recovery denial, SCE chose to simply leave the denied costs just where they were in its regulatory accounts, apparently convinced doing so would enable an opportunity to ask for them again and, if necessary, again.

TURN recommends that the Commission here make clear that the denial of cost recovery in the Track 3 decision is now a permanent disallowance of the fusing mitigation costs at issue. This response would appropriately signal SCE that it was inappropriate and unacceptable to attempt to use the memorandum account as a means of achieving the same level of rate recovery as would have occurred had the Track 3 decision found no deficiency in its showing. Alternatively, the Commission should deny rate recovery of the revenue requirement for an appropriate period given the circumstances. At minimum, this must include the revenue requirement through the end of the 2021 GRC period, which SCE estimates to be $18.4 million

[1479] *Id.*, p. 115.

as of December 31, 2024.[1480] TURN recommends that the Commission also deny rate recovery of the revenue requirement for the 2025 GRC period, again as an appropriate signal to SCE that its approach here was inappropriate and unacceptable.

38.3.2 Other GRC Ratemaking Proposals

38.3.2.1 SCE's Proposed "True-up" of 2023 Recorded Capital Expenditures

The Commission must reject SCE's proposal to treat recorded 2023 capital expenditures as recoverable even where opposed, in favor of continuation of the established practice of relying on the recorded figure where there is no opposition to doing so.

The development of SCE's test year 2025 revenue requirement requires a determination of the reasonable amount of 2023 capital expenditures to include in the calculations.[1481] In this GRC, 2023 is the "Base year +1," with costs initially presented as forecasts in the utility's direct testimony, but for which recorded amounts later become available and, as is typical, are included in the evidentiary record. For capital expenditures in 2024 and the 2025 test year, the Commission is resolving disputes that involve only forecasted figures. But for 2023 capital expenditures, the evidentiary record includes not only competing forecasts, but also SCE's recorded figures. However, because the recorded cost data were not provided until after intervenors had already served their prepared testimony, parties other than SCE had only very limited opportunity to review or conduct discovery on the 2023 recorded amounts.

[1480] Ex. SCE-40 (Update Testimony), p. 19.

[1481] The amounts associated with 2023 capital expenditures to be collected in 2023 and 2024 are the product of the test year 2021 GRC and the post-test year attrition mechanism adopted in that proceeding.

SCE's rebuttal testimony asks the Commission to adopt a virtually automatic "true up" of its 2023 capital expenditures, which appears to entail replacing the forecasted 2023 figures from the utility's testimony and workpapers with the recorded 2023 capital expenditures figures that the utility shared with parties on March 11, 2024. SCE's position seems to largely be premised on the misguided notion that once the utility has recorded costs for 2023, the burden of proof shifts such that intervenors must demonstrate that the costs reflect imprudence on the utility's part. The Commission must reject SCE's request as overreaching, and its underlying logic as unfounded and unsupportable.

TURN does not suggest the Commission should never adopt the 2023 recorded figures for the capital expenditures of a specific program or project in this GRC. In many instances there may be no explicit or implicit dispute over the use of the recorded figures, particularly when SCE's actual 2023 spending was at a level below its forecast or, in some cases, even below the intervenor's lower forecast for that year. In the absence of opposition, the Commission may well see fit to substitute the 2023 recorded figures for SCE's original forecasts for that year. However, there may still be disputed 2023 spending amounts, particularly where SCE's 2023 recorded figures continue to be higher than an intervenor's forecast of the reasonable amount for that year. The Commission will need to resolve those continuing disputes in the same manner and subject to the same burdens of proof and productions as any other issue, with the 2023 recorded figure as another available data point, but not as a presumptively reasonable figure entitled to the "true-up" SCE proposes. That is, whether the 2023 capital expenditure figures are reviewed on a forecasted or a recorded basis, SCE still bears the same burden of establishing the reasonableness of the amount it seeks to establish as reasonable and therefore eligible for inclusion in its authorized revenue requirement.

SCE's proposed "true-up" seeks to impose a single approach to <u>all</u> recorded capital expenditure figures for 2023, even where an intervenor objects to applying that approach to a particular project or program, and in doing so apply a presumption of reasonableness simply due to the costs now being recorded rather than forecasted. According to the utility, "SCE's ongoing capital-related revenue requirement [associated with SCE's 2023 capital costs] should ultimately reflect the total, recorded capital expenditures that closed as capital additions to rate base."[1482] In its view, any other outcome "would be inappropriate as it would constitute a disallowance of used and useful assets in service to customers."[1483] The utility describes its underlying view as "SCE is entitled to recover its investment on assets used and useful for customers, unless it can be shown that the spending was not reasonable."[1484]

It is hard to know where to start in debunking SCE's claims. First, in the test year 2018 GRC, the Commission explicitly rejected SCE's very similar near-automatic "true-up" position when it was applied to amounts that had been forecasted in the previous GRC cycle.[1485] While SCE was permitted to seek to "true-up" its rate base during a GRC test year to reflect above-authorized spending from the previous GRC cycle, the Commission noted "it should not be presumed that the true up will be authorized following review by the Commission." And the review would not focus solely on the reasonableness with regard to the timing of the investment but could instead extend to whether the amount spent "is fair and reasonable to ratepayers." SCE fails to even mention this earlier outcome, much less explain why the position that was rejected

[1482] Ex. SCE-18, Vol. 1, p. 115.

[1483] Ex. SCE-18, Vol. 1, p. 116.

[1484] *Id.*, p. 125.

[1485] D.19-05-020 (SCE test year 2018 GRC), pp. 342-343.

as applied to amounts forecasted in an earlier GRC should be adopted here when applied to amounts forecasted for the first year of this GRC period.

Second, the Commission has repeatedly rejected SCE's logic that the utility is entitled to recover costs of all "used and useful" plant when the utility took similar positions in previous GRCs.[1486] One of those rejections occurred in the context of SCE's rate base "true up" argument in the test year 2018 GRC.[1487] It is not at all clear how SCE saw fit to revive the argument here, again without any acknowledgment of these prior rejections.

Third, SCE's position is that once the utility has spent the money, the burden is on intervenors to establish imprudence and, absent such a showing, the Commission should permit the utility to include the recorded amount in rate base, even if it is substantially more than the utility forecasted for a given project or program.[1488] This position is legally and logically defective. The burden is on the utility to establish reasonableness and prudence of its recorded costs in circumstances such as these. "What critically matters is the prudency of the utility's actions, which the utility has the burden of proving, regardless of the testimonies of other parties."[1489] Here, SCE has provided no discussion of the prudency of its actions in 2023 with regard to the recorded amounts of capital expenditures; the utility's showing is, only slightly paraphrased, "we spent the money." For 2023 spending amounts that remain in dispute, a

[1486] D.15-11-021 (SCE test year 2015 GRC), p. 327 ["The fact that the new poles provide service to ratepayers and are used and useful is insufficient to prove that the expenditures to purchase and install the poles should be recovered form rates. That question turns on the prudency of the investment edecision."]. The Commission reiterated this approach in D.19-05-020 (SCE test year 2018 GRC), pp. 328-329. *See also* D.19-05-020, p. 332 ["SCE cannot establish reasonableness based simply on a claim that an expenditure was made and has resulted in an investment which is used and useful for SCE's customers."

[1487] D.19-05-020, pp. 342-343.

[1488] Ex. SCE-18, Vol. 1, pp. 116-117.

[1489] D.21-10-036 (Rehearing of PG&E test year 2019 GT&S rate case), p. 6.

"showing" that consists of nothing more than the recorded amount cannot meet the utility's burden of proving prudence with regard to that amount. SCE's approach also flies in the face of reality, as it would tacitly treat the 2023 recorded spending figures as if intervenors had a reasonable opportunity to review or address the prudence or reasonableness of figures that were first provided <u>after</u> their prepared testimony had been served.[1490] Similarly unsupported is the implication that having recorded cost figures should somehow resolve disputes over the 2023 cost forecasts. For example, TURN has recommended the Commission authorize 2023 spending for SCE's Overhead Conductor program at a level far below the amount SCE had originally forecasted, based partly on arguments that the scale of SCE's proposal and the failure to adequately consider less expensive alternatives rendered the forecast unreasonable. The fact that SCE now has a 2023 recorded spending figure for this program does not resolve any of those challenges, and nowhere does SCE explain why the Commission should treat the recorded figures as effectively eliminating such disputes.

Fourth, SCE relies on baseless claims that its approach is consistent with the modifications adopted to the Rate Case Plan in D.20-01-002. In that decision the Commission merely noted that having the Base Year +1 recorded cost data in the evidentiary record for a GRC is often helpful to the decision-making process.[1491] There is nothing in the decision that would suggest the Commission intended to make the Base Year +1 recorded cost data determinative of anything, or to effectively shift the burden of proof among the parties.

[1490] Under the procedural schedule established for this proceeding, intervenor testimony was due on February 29, 2024. On March 11, 2024, SCE served its preliminary 2023 recorded capital expenditures figures. Thus, at all relevant times leading up to the presentation of their prepared testimony, in nearly all instances intervenors would not have had available to them even the preliminary recorded 2023 figures.

[1491] D.21-01-002, pp. 61-62.

Finally, even if there were any legal or logical basis for the utility's position, the Commission should still decline to adopt it here due to the procedural defect of SCE choosing to wait until its rebuttal testimony to present its expanded proposal for a true-up. TURN found nothing in SCE's direct showing that even suggested the utility intended to include this proposal as part of its GRC request. Given that the proposal represents fundamental shifts in general GRC ratemaking practices in terms of the utility's burden of proving reasonableness and prudence, and would effectively reverse outcomes from prior GRCs when SCE's similar requests were denied, the Commission should recognize that waiting until rebuttal testimony to make the new request is an unfortunate and unacceptable tactic.

Again, TURN is not in any way suggesting that the 2023 recorded capital expenditure figures should serve no purpose to the Commission's decision-making process here. As the Commission has recognized in the past, "where a proposal or funding request has not been challenged by an intervenor, we generally adopt the utility's request as a practical reality of the decision-making process."[1492] Here, for programs or projects where SCE's 2023 forecast was not challenged and no party raises a challenge to the 2023 recorded figure, the "practical reality" would likely be applicable. But in those instances where the 2023 spending level remains in dispute, the Commission must decide whether SCE's showing of reasonableness and prudence warrants authorizing recovery of any amount, whether it's the utility's 2023 forecast, the utility's recorded expenditures for 2023, the intervenor-sponsored forecast for 2023, or some other figure. For such a program or project, SCE's recorded figure for 2023 gives the Commission an additional data point, nothing more. It does <u>not</u> establish that the recorded spending amount is

[1492] D.93-12-043 (SoCalGas Test Year 1994 GRC); 1993 Cal. PUC LEXIS 728, *12; 52 CPUC 2d 471.

reasonable, and it does not shift the burden to intervenors to disprove prudence, reasonableness, or any other element necessary for authorization of rate recovery.

38.4 Forecasts Of Sales, Customers, And New Meter Connections

In Section 12.1 above, TURN addresses most issues covered by SCE's direct and rebuttal testimony addressing the forecast of residential customers and new meter connections for residential, commercial, and agricultural customers (Ex. SCE-07V01 and Ex. SCE-18V01). For instance, TURN addresses the common shortcomings in SCE's forecasts of both residential new meters and residential customers, including issues with SCE's regression analyses linking housing starts to customers and new meters, as well as the reliability of SCE's housing start forecast, which is the primary explanatory variable in its forecast models. TURN also addresses many of SCE's criticisms of TURN's forecast methodology for residential customers and new meter connections, which entails using a 10-year average growth rate for residential customers to forecast future customers and a 10-year average growth rate for new residential meter connections to forecast new meter connections. TURN further addresses modifications to some of its procedural recommendations presented in testimony in consideration of SCE's rebuttal testimony. Finally, TURN explains that it has accepted SCE's recommendation that TURN update its 10-year historical average growth rates used to forecast both residential customers and new meter connections to include 2023 recorded data.

TURN's discussion here is limited to presenting TURN's updated residential customer forecast recommendation following TURN's incorporation of 2023 recorded data. As SCE recommended, TURN is willing to update its 10-year historical average growth rate for residential new customers to incorporate the 2023 recorded residential customer count

(4,578,185) provided by SCE in rebuttal testimony.[1493] Incorporating 2023 recorded data would impact the average growth rate by moving the series from 2013-2022 to 2014-2023 and impact the starting point for escalating customer count by the new growth rate.

However, TURN does not believe that SCE's recorded residential customer count for all years that are necessary to update this calculation, 2014 through 2023, is in the record; it may only be in TURN's confidential workpapers which SCE has but have not been admitted into evidence.[1494] As a result, TURN cannot officially provide an updated calculation. TURN unofficially indicates that the resulting 2014-2023 growth rate is higher than the 2013-2022 growth rate of 0.59% and the 2025 customer forecast is higher than SCE's forecast of 4,626,593. Accordingly, TURN no longer opposes SCE's 2025 residential customer forecast. TURN continues to recommend that customer growth be determined in a manner that is transparent, practical, and reasonable, like TURN's 10-year average historical growth rate. As such, TURN would not oppose the adoption of the updated forecast resulting from TURN's forecast methodology, should SCE be interested in seeking to amend the record to include the necessary data.

[1493] Ex. SCE-18V01, p. 82.

[1494] *See* Ex. SCE-18V01, Appendix A, p. A43 (SCE-TURN-005, Q3)(referring to a confidential workpaper that was provided as part of TURN's response but not attached by SCE to its rebuttal testimony). SCE provides 2021-2023 recorded residential customers in Ex. SCE-07V01, p. 98 and Ex. SCE-18V01, p. 76. Cal Advocates provides 2017-2022 recorded residential customers in Ex. CA-27, p. 2.

38.5 Present Rate Revenue

38.6 Cost Escalation

38.7 Other Operating Revenues (Excluding Non-Tariffed Products And Services)

38.8 Other Operating Revenues – Non-Tariffed Products And Services

In 1999, the Commission adopted a revenue sharing mechanism for non-tariffed products & services ("NTP&S") that awarded SCE shareholders 70% of the revenue or 90% if shareholders incur more than $225,000 of expense.[1495] Since that time, SCE shareholders have been rewarded with more than $1.342 billion of revenues while ratepayers received $661.1 million,[1496] even though ratepayers paid for the assets *and* paid shareholders for the returns on the rate base.

38.8.1 SCE's Lack of Auditable Records Along with the Inherent Conflict of Interest in the Determination of Incremental Costs Should Result in the Finding that SCE Has Not Met Its Burden of Proof

SCE states that it uses the "but for" test to determine whether cost is incremental and thus charged to the shareholders.[1497] However, as TURN noted previously, 1) SCE alone conducts the "but for" test that determines which costs are incremental and should therefore be charged to shareholders, 2) SCE does not have a record of the "but for" tests, which renders an audit of these tests impossible, and 3) SCE does not keep a record or time log of its NTP&S Program's use of utility resources.

SCE claims that its NTP&S Program has been subject to several audits, including one by Baker Tilly in 2015 and audits by the State Controller's Office, and that there were no findings

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[1495] D.99-09-070, Attachment A, pp. 3-4.

[1496] Ex. TURN-10, p. 12, citing DR TURN-SCE-90, Question 7.

[1497] Ex. SCE07V01, p. 124.

related to Rule VII.[1498] It is unclear what was the scope of the Baker Tilly audit in 2015 because SCE claims that it is unable to locate a copy of the audit "after a reasonable search" since it is no longer subject to document retention obligations,[1499] which TURN does not find credible. However, it is clear that the State Controller's Office was never able to audit whether incremental costs were properly captured and assigned to shareholders – it was only able to *trace the incremental costs and gross revenue to SAP ERP general ledger details to ensure accuracy of reporting*.[1500] In other words, due to the lack of auditable records, the State Controller's Office was not able to audit whether incremental costs were properly assigned to shareholders, since SCE alone performs the determination and there are no records that can be audited in terms of which costs SCE deemed to be incremental versus which costs it deemed not to be incremental.

To explore this further, TURN asked SCE to provide a sample of documents it provided to the auditors "to examine whether all incremental costs for NTP&S were properly assigned to shareholders."[1501] SCE responded that it provided auditors with SCE's procedure for preparing its annual report, NTP&S training script, guidelines and procedure for recording incremental costs, list of accounting for SCE's reported incremental costs, and NTP&S training presentation.[1502] Clearly, none of these documents would allow an auditor to determine whether incremental costs for NTP&S were properly assigned to shareholders – the documents are simply

[1498] Ex. SCE07V01, p. 126.

[1499] Ex. TURN-10, p. 13, citing DR TURN-SCE-090, Question 2.

[1500] Ex. TURN-10, p. 13, citing SCE Audit Report Affiliate Transaction Rules, December 2020, p. 14.

[1501] Ex. TURN-10, p. 13, citing DR TURN-SCE-090, Question 2.

[1502] Ex. TURN-10, p. 13, citing DR TURN-SCE-090, Question 2.

guidelines, training, and reports. The auditor does not get to see which costs SCE determined were incremental versus non-incremental, and whether SCE's determination was reasonable or proper. Again, the auditor can only audit the accounting trail *after* SCE has already determined which costs and how much are incremental.

The fact that SCE is the sole arbiter of which costs should be assigned to ratepayers versus shareholders is a clear conflict of interest.[1503] Furthermore, not only is there a clear conflict of interest, there are no auditable records to show that incremental costs have been properly assigned to shareholders, as discussed above. The combination of both should result in the Commission's finding that SCE has not met its burden of proof to demonstrate that incremental costs for NTP&S have been properly assigned to shareholders. SCE claims that it is too burdensome to keep these records, yet it also claims that these tests are consistently and correctly performed. Essentially, the public should just trust SCE. That does not give the public sufficient comfort, and it is not enough to meet SCE's burden of proof.

<u>Response to SCE's Rebuttal</u>. In its rebuttal, SCE claims that TURN nor any other party "has identified any NTP&S incremental costs that have been inadvertently included in this GRC revenue requirement,"[1504] and that "SCE's NTP&S and incremental costs have consistently been audited as part of the biannual Affiliate Transactions Audit conducted by the Energy Division or their external auditors."[1505] However, as obviously and thoroughly demonstrated by TURN during evidentiary hearings, it is impossible for TURN or other stakeholders to examine whether

[1503] Even though SCE attempted to argue in its rebuttal testimony (Ex. SCE18V01, p. 105) that SCE is not the sole arbiter of this decision, SCE's witness conceded on the stand that Edison alone makes the decision regarding which costs are considered incremental (12 RT 1167:8 – 1168:12).

[1504] Ex. SCE18V01, p. 94.

[1505] Ex. SCE18V01, p. 95.

NTP&S incremental costs have been included in the GRC revenue requirement precisely because SCE does not keep or maintain any records related 1) how much and why it determined certain costs were non-incremental,[1506] and 2) an accounting of costs that it determined to be non-incremental.[1507] In addition, because SCE does not keep any records, it is also impossible for the Commission or other auditors to conduct an audit of whether any incremental costs have been improperly classified as non-incremental.[1508] During evidentiary hearings, SCE absurdly suggested that despite there being no auditable records, the auditors should trust that SCE employees are doing the right thing based on its training and guidelines.[1509] When asked how the Commission or other stakeholders could find evidence that incremental costs were inappropriately classified as non-incremental if there is no record of non-incremental costs, SCE absurdly stated that the auditors should ask SCE employees, "Have you done anything inappropriate?"[1510]

38.8.2 The Commission Should Order SCE to Maintain Auditable "But For" Tests and Time Logs at Shareholder Expense

SCE states that a study by KPMG found that it would cost between $4.36 to $5.72 million annually to implement non-incremental resource tracking.[1511] SCE also provided alternates at lower costs, ranging from Time Sheets to Process Mining.[1512] However, it is unclear

[1506] 12 RT 1143:25 – 1145:19.

[1507] 12 RT 1155:7 – 1156:10.

[1508] 12 RT 1147:10 – 1149:6.

[1509] 12 RT 1149:7 – 1150:4.

[1510] 12 RT 1150:7 – 1151:11.

[1511] Ex. SCE07V01, p. 134.

[1512] Ex. SCE07V01, p. 136.

whether these alternatives are as effective as maintaining "but for" logs, and whether these alternatives would lend themselves to auditing. Thus, the Commission should order SCE to maintain auditable "but for" tests and time logs at shareholder expense.

Proper record keeping and cost tracking are part of the costs of doing business, which is why shareholders should be responsible for these costs. Even using SCE's own "but for" test would result in the same conclusion – since SCE would not have incurred these record keeping costs *but for* the NTP&S Program, these costs should be deemed incremental and charged to shareholders.

TURN notes that even if these record keeping costs were charged to shareholders, SCE shareholders would still achieve an incredibly high level of return for the NTP&S Program. If we deduct the highest range in the cost of $5.72 million per KPMG's study from SCE shareholders' after-tax net profit in 2022, it would result in $9.28 million of after tax net profit from an investment of $38.1 million,[1513] or an outrageous return of 24.4%, which is 310% of SCE's authorized cost of capital.[1514]

Thus, it is more than reasonable for the Commission to order SCE to maintain auditable "but for" tests and time logs at shareholder expense if shareholders can still achieve a 24.4% return even assuming the highest range of the estimated costs.

[1513] Ex. TURN-10, p. 15, citing DR TURN-SCE-090, Question 7.

[1514] Ex. TURN-10, p. 15, citing SCE AL 5120-E, SCE's authorized rate of return is 7.87% for 2024.

38.8.3 The Unreasonable Sharing Mechanism and Arbitrary Determination of Incremental Costs Have Allowed Shareholders to Achieve Astronomical Levels of Profitability Under the NTP&S Program

The unreasonable sharing mechanism and SCE's ability to arbitrarily determine which costs should be borne by shareholders have allowed shareholders to achieve astronomical levels of profitability under the NTP&S Program. According to SCE's own records, SCE shareholders have achieved an average return of 39.6% from the NTP&S over the last 9 years:[1515]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average
Cost to shareholders ($M)	$29.4	$27.8	$33.8	$35.2	$39.2	$31.6	$33.9	$36.3	$38.1	$33.9
Shareholder After-tax Net Profit ($M)	$15.3	$17.1	$11.9	$11.6	$9.4	$13.5	$12.9	$14.1	$15.0	$13.4
Shareholder Return (%)	**52.0%**	**61.5%**	**35.2%**	**33.0%**	**24.0%**	**42.7%**	**38.1%**	**38.8%**	**39.4%**	**39.6%**

Over the last three years from 2020 to 2022, the average return for shareholders was similarly at 38.8%.

SCE's current authorized cost of capital (or rate of return) is 7.87% per SCE AL 5120-E. Thus, a return of 39.6% would be an eye-popping 503.2% of SCE's authorized rate of return. Even if we use SCE's authorized cost of common equity of 10.75% as a comparison,[1516] the shareholders were still able to achieve an outrageous 368.4% of its authorized cost of common equity under the NTP&S Program!

The Commission should recognize that this astronomical level of profitability for shareholders is unreasonable, especially if as noted above, there a clear conflict of interest in the

[1515] Ex. TURN-10, p. 16, citing DR TURN-SCE-090, Question 7.

[1516] Ex. TURN-10, p. 16, citing SCE AL 5120-E.

way that incremental costs are determined by SCE, and there are no auditable records to show that incremental costs have been properly assigned to shareholders.

Response to SCE's Rebuttal. In its rebuttal, SCE claims that over the life of SCE's GRSM, customers have received 72% of the net revenues (compared to 28% for shareholders), and that customers rate of return is "mathematically infinite" compared to the 39.6% of after-tax net return for shareholders. SCE's assertions are nonsensical and should be rejected by the Commission. First, a share of net revenues is meaningless without a comparison to the amount of investment or expenses borne by each party. For example, if Party A receives 90% of net revenues (compared to 10% for Party B), does that mean Party A is better off? Of course not, since one would need to consider the amount of investment by each party in order to calculate the rate of return. Party A could easily have a much higher percentage of the total net revenue but achieve a much lower rate of return. The same principle applies here when comparing ratepayers to shareholders. SCE concedes that ratepayers paid billions of dollars for the assets that are being used to provide NTP&S, and shareholders paid zero.[1517] SCE further concedes that it would not be possible to offer these NTP&S if ratepayers did not pay billions of dollars for these assets.[1518] Hence, the Commission should reject SCE's attempt to argue that ratepayer have somehow received a better deal under the GRSM structure because they've received 72% of the net revenues.

38.8.4 SCE's Usage of Ratepayer Funded Assets Raises Questions About Overbuilding of Capacity for Non-Utility Uses

SCE states that Edison Carrier Solutions ("ECS") uses "SCE's temporarily available

[1517] 12 RT 1185:7 – 1187:9.

[1518] 12 RT 1186:18 – 1187:2.

excess capacity on SCE's fiber network to provide commercial telecommunication non-voice services to non-residential customers."[1519]

SCE's record shows that as of 2023, SCE is only using 24.3% of rate-base fiber network capacity to provide energy utility operations.[1520] The remaining 75.7% is either used for NTP&S or unused. SCE's usage appears little changed from 2017, six years earlier, when it was only using 22.4% to provide energy utility operations,[1521] which represents an increase of only 1.9% after six years. In fact, as of 2023, 68% of SCE's fiber network capacity remains unused,[1522] which is an astonishing percentage. SCE's usage of ratepayer funded fiber network capacity raises questions about the overbuilding of capacity at ratepayer expense, potentially to enable SCE to provide NTP&S on the unused capacity.

In its rebuttal testimony, SCE attempts to argue that the "existence of capacity in excess of near-term electric utility operational needs is a prudent and natural consequence of the construction of fiber facilities to meet those utility needs" because it designs the fiber network to have enough capacity for the projected 15-20 year useful life.[1523] However, SCE's argument is belied by its own evidence. If that were the case, one would expect that over a six-year period, the excess capacity should reduce by 30% (6 divided by 20) to 40% (6 divided by 15). Yet, over a six-year period, SCE's excess fiber network capacity only reduced by 2.5%.[1524] Hence, SCE's claim does not add up.

[1519] Ex. SCE07V01, p. 129.

[1520] Ex. TURN-10, p. 17, citing DR TURN-SCE-090, Question 3.

[1521] Ex. TURN-10, p. 17, citing DR TURN-SCE-090, Question 3.

[1522] Ex. TURN-10, p. 17, citing DR TURN-SCE-090, Question 3.

[1523] Ex. SCE18V01, p. 110.

[1524] 1.9% / 75.7% = 2.5%.

This over-building was not the intent of the Commission when it adopted a sharing mechanism. The intent of the Commission was to provide a mechanism for the IOUs to enhance utilization of existing but temporarily underutilized utility assets.[1525] However, the unjust sharing mechanism awarding 90% to shareholders created a perverse incentive for SCE to take undue advantage of the opportunity and used ratepayer dollars to build far more fiber optic network capacity than necessary, which then used the extra capacity to enrich shareholders.

Both the Proposed Decision and the Alternate Proposed Decision in Application 17-02-001 agreed. The Proposed Decision stated that "[t]he record demonstrates that SCE's non-tariffed fiber optic offering has increased to an inappropriate magnitude" and that "the rules permitting utilities to offer non-tariffed products and services and the 90/10 shareholder/ratepayer revenue sharing allocation established for SCE in D.99-07-070 were not intended to apply to this magnitude of overcapacity of utility assets."[1526] The Alternate Proposed Decision similarly stated, "the record demonstrates that SCE's non-tariffed dark fiber optic offering has reached a level far greater than that envisioned for non-tariffed product or service (D.97-12-088, as amended by D.98-08-035), and on which the 90/10 shareholder/ratepayer revenue sharing is based (D.99-09-070)."[1527] The Alternate Proposed Decision further noted that the Commission's intent when authorizing a sharing mechanism for Non-Tariffed Products & Services ("NTP&S") was that the products would "stem from only incidentally underutilized utility assets, not from a systematic build-up of assets funded by ratepayers."[1528]

[1525] D.99-09-070, p. 58, Attachment A.

[1526] A.17-02-001, January 9, 2018 Proposed Decision, p. 20, Conclusions of Law #1.

[1527] A.17-02-001, July 5, 2018 Alternate Proposed Decision, p. 9.

[1528] A.17-02-001, July 5, 2018 Alternate Proposed Decision, p. 8.

This is an important question that needs to be addressed by the Commission as part of a comprehensive review of SCE's NTP&S Program, discussed further in the section below.

38.8.5 The Commission Needs to Perform a Comprehensive Review of the NTP&S Program, Including the Outdated Sharing Mechanism that Has Unreasonably Enriched Shareholders at Ratepayers' Expense

SCE asserts that the Commission has affirmed on numerous occasions that "any proposed changes to SCE's GRSM is subject to a separate rulemaking proceeding."[1529] However, that is no longer accurate with the recent issuance of PG&E's recent GRC decision, D.23-11-069. In that decision, the Commission approved PG&E's NTP&S program for only two years out of the four-year GRC cycle and noted that "longer-term continuation of this program, with funding by ratepayers, requires further information and consideration by the Commission."[1530] The Commission also ordered PG&E not to distribute NTP&S profits to shareholder but instead retain all profits in an interest-bearing account. If PG&E wishes to continue the program, PG&E is required to file an application to justify the continuation of the program, including "(1) details on the benefits to ratepayers, (2) how shareholders (or ratepayers) bear risks of potential loss, (3) information about its profit-sharing mechanism, and (4) how the program aligns with the Commission's Affiliate Transaction Rules," as well as detailed accounting, in addition to a comprehensive audit of the program.[1531] Thus, SCE's statement that the sharing mechanism needs to be addressed in a rulemaking proceeding is no longer correct.

SCE's NTP&S Program is similarly due for a comprehensive review by the Commission, including issues TURN addressed above – conflict of interest, potential overbuilding of capacity,

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[1529] Ex. SCE07V01, p. 124.

[1530] D.23-11-069, pp. 528-529.

[1531] D.23-11-069, pp. 530-531.

accurate and auditable determination of incremental costs, astronomical levels of shareholder returns, and the revenue sharing mechanism. It is absurd that the dollar amount allocated 100% to ratepayers has never been adjusted after 25 years and remains the same amount ($16.72 million) as 1999 – this means that adjusted for inflation, ratepayers are only receiving $8.94 million today compared to $16.72 million, a 46.5% decrease,[1532] while shareholders continue to receive 70-90% above the threshold. This unjust and unreasonable result needs to be revisited by the Commission.

In its rebuttal testimony, SCE claimed that the $16.72 million threshold amount was put in place to reflect the level of NTP&S and associated revenue at the time of SCE's 1995 GRC.[1533] SCE further claimed that "many of the services that made up the $16.7 million Threshold Amount are no longer being offered by SCE," and that the $16.7 million threshold should be either reduced significantly or even eliminated.[1534] Here, once again SCE's claim is belied by its own evidence. SCE's record shows that even though 13 areas of NTP&S that made up the $16.7 million are no longer being offered in 2023,[1535] the revenue from the remaining NTP&S that made up the original $16.7 million now totals to $27.5 million in 2023,[1536] a 64.6% increase! This is further evidence that the outdated and inappropriate $16.7 million threshold from 25 years needs to be revisited by the Commission.

When the Commission adopted the sharing mechanism in 1999, the Commission also

[1532] Ex. TURN-10, p. 19; $1 in 1999 = $1.87 in 2024.

[1533] Ex. SCE18 V01, p. 106.

[1534] Ex. SCE18 V01, p. 106.

[1535] Ex. TURN-200, p. 4.

[1536] Ex. TURN-200, p. 4.

recognized that giving ratepayers 10% of revenues "may fall on the low side of the range of reasonableness."[1537] The most recent decision addressing revenue sharing mechanisms of which TURN is aware is the Sempra Utilities' 2012 general rate case decision. There, the Commission adopted a 25/75 shareholder/ratepayer revenue allocation for SDG&E's research and development activities (rather than the 40/60 shareholder/ratepayer allocation SDG&E proposed).[1538] Furthermore, in a recent application in March 2017, SDG&E also proposed allocating 25% of the revenue from sale or lease of Intellectual Property ("IP") rights to shareholders and 75% to ratepayers.[1539]

In Application 17-02-001, after reviewing the record, Administrative Law Judge ("ALJ") Yacknin issued a Proposed Decision that adopted a 25/75 shareholder/ratepayer sharing mechanism.[1540] Separately, Commissioner Rechtschaffen issued an Alternate Proposed Decision that adopted a 50/50 shareholder/ratepayer sharing mechanism.[1541] ALJ Yacknin's Proposed Decision *increased* ratepayer allocation by 650%, while Commissioner Rechtschaffen's Alternate Proposed Decision increased ratepayer allocation by 400%! Clearly, both determined that allocating only 10% of revenues to ratepayers was unreasonable and should be increased significantly.

SCE's unjust and unreasonable sharing mechanism needs to be revisited by the Commission. TURN recommends that the Commission order a comprehensive review of SCE's

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[1537] D.99-09-070, p. 29.

[1538] D.13-05-010 (Sempra Utilities' 2012 GRC), pp. 600 and 1023-1024.

[1539] A.17-03-019, SDG&E Application, p. 6. The Commission adopted the proposed sharing in its Proposed Decision, but SDG&E ultimately withdrew the application.

[1540] A.17-02-001, January 9, 2018 Proposed Decision, p. 8.

[1541] A.17-02-001, July 5, 2018 Alternate Proposed Decision, p. 10.

NTP&S Program as well as an audit, consistent with the recent Commission decision for PG&E's GRC. The Commission should authorize the NTP&S Program for two more years, and if SCE wishes to continue its NTP&S program, it should be required to file an application containing at a minimum the same information PG&E is required to submit. Furthermore, a comprehensive audit should be conducted by an independent auditor within 12 months of a Commission decision in this proceeding, consistent with D.23-11-069.

38.9 Operation And Maintenance Expense Forecast

38.10 Overhead Allocation

38.11 Reinvestments In Utility-Owned Generation Resources

39. RATE BASE

39.1 Plant In Service, Reserves, And Depreciation Expense

SCE's GRC forecast includes an estimate of rate base, which consists of three components: net plant-in-service, working capital, and accumulated deferred income taxes.[1542] Net plant-in-service is SCE's electric plant-in-service and accumulated depreciation and amortization.[1543] SCE asks the Commission to find that its electric plant-in-service (plant) estimates are reasonable for purposes of determining GRC revenue requirements.

However, as TURN demonstrates in its testimony, SCE prematurely includes in its plant estimates certain costs recorded to memorandum accounts that have yet to be found reasonable for cost recovery by the Commission, including costs recorded to the Catastrophic Event Memorandum Account (CEMA) and Wildfire Mitigation Plan Memorandum Account

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[1542] Ex. SCE-07V02, p. 2.

[1543] Ex. SCE-07V02, p. 3.

(WMPMA).[1544] TURN identified $883 million in plant costs in the RO Model associated with capital costs booked to CEMA and MWPMA that were, at the time of TURN's testimony, undergoing reasonableness review in other proceedings, plus $41 million in plant associated with capital costs booked to CEMA for which SCE had yet to file a reasonableness review application.[1545] TURN recommended that these costs be excluded from plant within SCE's RO Model unless and until the Commission conducts a reasonableness review and approves cost recovery.

Since that time, the Commission has resolved two of the three reasonableness review proceedings considering costs SCE included in plant, while the third is still pending.[1546] In D.24-03-008, issued in A.22-06-003, the Commission authorized most of SCE's requested cost recovery but deferred consideration of $21.09 million in WMPMA 2021 construction work-in-progress capital expenditures to a later proceeding.[1547] In D.24-05-037, issued in A.22-03-018, the Commission found reasonable and authorized recovery of all requested capital expenditures (and all but $3.216 million in O&M expense).[1548] The third proceeding, A.23-10-001, has a proposed decision expected in the second quarter of 2025.[1549] SCE has also submitted a new application, A.24-04-005, seeking reasonableness review of costs recorded to CEMA for some,

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[1544] Ex. TURN-19 (Yap), pp. 2-4.

[1545] Ex. TURN-19 (Yap), pp. 2 (Table 1) (identifying CEMA and/or WMPMA costs under review in A.22-03-018, A.22-06-003, and A.23-10-001), 4 (Table 2) (identifying CEMA costs for which SCE had yet to request a reasonableness review).

[1546] See Ex. TURN-19 (Yap), p. 2, Table 1.

[1547] D.24-03-008, as modified by D.24-06-025, p. 25. The Commission recounted SCE's statement that these costs are included in A.23-10-001. *Id.*

[1548] D.24-05-037, p. 22.

[1549] A.23-10-001, Email Ruling Modifying Procedural Schedule, 5/2/24.

but not all, of the CEMA events identified by TURN as not yet subject to a request for review by SCE.[1550] That proceeding is currently pending.

Even if the total dollar amount of unreviewed (and unauthorized) memorandum account balances is now smaller than at the time of TURN's testimony, the policy issue remains the same. The Commission should make clear that SCE may not include costs booked to memorandum accounts in plant in the RO Model unless the Commission has found those costs reasonable and authorized cost recovery. Additionally, the Commission should ensure that the GRC revenue requirements authorized in this proceeding for test year 2025 and attrition years 2026-2028 do not include capital costs prematurely included in plant by SCE.

39.1.1 A Utility Cannot Receive Cost Recovery for Capital Expenditures Recorded in Memorandum Accounts Until the Commission Reviews Those Costs for Reasonableness and Determines that They Were Prudently Incurred.

The Commission authorizes utilities to create memorandum accounts to track uncertain costs associated with specific activities that have yet to be found reasonable and necessary, such that the utility may apply for future cost recovery without violating the prohibition on retroactive ratemaking.[1551] At issue in this proceeding are two memorandum accounts, CEMA and WMPMA. The Commission has made it abundantly clear that costs recorded in these memorandum accounts cannot be passed on to ratepayers without a Commission order approving cost recovery after a reasonableness review.

[1550] Ex. TURN-19 (Yap), p. 4, Table 2.

[1551] *See, e.g.,* D.23-05-003, p. 6 (describing the role of memorandum accounts generally); Resolution E-3238, p. 2 (discussing the impetus for the creation of catastrophic event memorandum accounts).

In Resolution E-3238, the Commission authorized the utilities to create CEMA but cautioned that "authorizing the recording of costs associated with a disaster should not be construed as a prejudgment of the appropriateness of recovery of any amounts so accumulated."[1552] The Commission clarified,

> The Commission will examine closely all costs recovered in a utility's catastrophic event memorandum account before allowing their recovery in customers' rates. … The costs recorded in the account will not be recoverable in rates without a request by the affected utility, a showing of their reasonableness, and approval by the Commission. Such a request must be made by formal application specifically for that purpose, by inclusion in a subsequent general rate case or other ratesetting application.[1553]

Including CEMA costs in the RO Model that are yet-to-be reviewed and approved for cost recovery by the Commission will result in the prohibited inclusion of these costs in customer rates.

Similarly, in D.23-11-069, the Commission addressed PG&E's inclusion of costs in its GRC RO Model that were recorded to CEMA and WMPMA but not yet reviewed for reasonableness (as well as costs recorded to other memorandum accounts). The Commission concluded that such costs must be excluded from plant, explaining, "For amounts recorded in memorandum accounts, the Commission must first review those costs for reasonableness, and to include costs in rate base they must be both used and useful as well as prudently incurred."[1554]

SCE asserts that it is appropriate to include these unapproved capital expenditures recorded to CEMA and WMPMA in its RO Model because these capital expenditures "represent used and useful net plant-in-service capital costs associated with expected rate base

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[1552] Resolution E-3238, p. 2.

[1553] Resolution E-3238, pp. 2-3.

[1554] D.23-11-069, issued in PG&E's 2023 GRC, p. 775 (citing Cal. Pub. Util. Code Section 451).

amounts."[1555] SCE is incorrect. In D.19-05-020, the Commission explained, "SCE cannot establish reasonableness based simply on a claim that an expenditure was made and has resulted in an investment which is used and useful for SCE's customers."[1556] Instead, SCE must first seek and receive a determination from the Commission that the costs are just and reasonable for recovery.

39.1.2 The Commission Should Direct SCE to Exclude from Plant Within its RO Model All Costs Recorded to Memorandum Accounts that the Commission Has Not Found Reasonable for Recovery.

As explained above, ratepayers should not pay for capital expenditures recorded to memorandum accounts unless the Commission first determines that SCE's costs were incremental and prudently incurred and then orders cost recovery. However, the unauthorized capital expenditures recorded to CEMA and WMPMA that SCE has included in plant in the RO Model will ultimately end up in GRC rates unless the Commission orders their removal.

In D.23-11-069, the Commission removed from PG&E's authorized GRC revenue requirement the test year and attrition year revenue requirements associated with the capital expenditures recorded in PG&E's memorandum accounts that the Commission had yet to find reasonable for recovery.[1557] The Commission pointed out that "PG&E will have the opportunity to seek recovery of such costs but must first request and obtain a determination from the Commission that the costs are just and reasonable."[1558] The same is true for SCE. Accordingly, the Commission should remove from SCE's test year and attrition year revenue requirements all

[1555] Ex. TURN-19, pp. 4-5 (quoting SCE's responses to TURN data requests); Ex. SCE-18V02A, pp. 2-3.
[1556] D.19-05-020, p. 333.
[1557] D.23-11-069, pp. 775-776.
[1558] D.23-11-069, p. 776.

costs recorded to memorandum accounts that the Commission has not found reasonable for cost recovery.

In rebuttal testimony, SCE suggests that if the Commission ultimately disallows any of the costs recorded to memorandum accounts in a reasonableness review, "the utility could then make a change to its GRC revenue requirement to reflect the disallowance."[1559] This adjustment will not make ratepayers whole unless SCE also refunds all capital-related revenue requirements already collected through GRC rates before the change. The simpler approach is to exclude the capital costs still subject to reasonableness review and only include them in GRC revenue requirements once the Commission has authorized cost recovery.

To facilitate this update to SCE's plant estimate, TURN recommends that the Commission direct SCE to provide an updated accounting of all capital costs in its plant figures in the RO Model that are recorded in memorandum accounts and have yet to receive a reasonableness determination and cost recovery authorization by the Commission. This exhibit should be provided as a late-filed exhibit with accompanying motion, and filed as late as possible but prior to the Commission's issuance of the proposed decision.

39.2 Working Capital (Excluding Customer Deposits)

39.2.1 Income Tax Lag

TURN's prior analysis in SCE's 2021 GRC recognized that due to net operating loss and other tax credit carryovers, SCE hadn't paid cash federal income taxes since 2009 and cash California income taxes since 2016.[1560] Furthermore, SCE was unlikely to have an actual tax

[1559] Ex. SCE-18V02A, p. 4.

[1560] D.21-08-036, p. 498.

burden during the 2021 rate case cycle.[1561] In D.21-08-036, the Commission concluded that SCE's forecast of lag days for state and federal income taxes were unreasonable because they were unlikely to be representative of the lag days for the test year. As such, SCE's proposal was not an appropriate basis for forecast ratemaking:

> We do not find SCE's forecasted lag days for state and federal income taxes to be reasonable because SCE fails to demonstrate that they are likely to be representative of the lag days for the test year. SCE fails to justify going back to tax payment history for 2005-2009 and 2011-2016 to forecast lag days for 2021. We cannot ignore the reality that SCE last paid federal income taxes in 2009 and state income taxes in 2016. Moreover, SCE does not attempt to deny that its tax situation is unlikely to change in the upcoming GRC cycle. SCE generally agrees that it has incurred significant deductible tax costs over the past 10 years and that the deductibility of potential wildfire obligations could limit federal or state tax liabilities for the next few years.
>
> Given that SCE has not paid federal income taxes for several GRC cycles and state income taxes since before the last GRC cycle and given the lack of evidence that SCE's tax situation is likely to change for this GRC cycle, we find TURN's proposal to use 365 lag days for both state and federal taxes to be reasonable for purposes of calculating the appropriate expense lag adjustment to working cash.[1562]

Contrary to being a" flawed decision" as SCE asserts in its rebuttal,[1563] D.21-08-036 appropriately recognized that forecast ratemaking results in just and reasonable rates which reflect the cost of service when the forecast values are *reasonable*. If this fails to be the case, the Commission is correct in departing from standard practice to set rates. If the Commission were

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[1561] D.21-08-036, p. 499, citing Ex TURN OB at 279.

[1562] D.21-08-036, p. 500.

[1563] Ex SCE-18, Vol 02A, p. 24.

tied to a methodology that resulted in an unreasonable forecast, it would have no mechanism by which to protect ratepayers from the negative effects of inflated utility forecasts in rates.

Further, D.21-08-036 explicitly notes that:

> OII 24 "does not foreclose the possibility under extraordinary circumstances, it would be appropriate for the Commission to consider tax impacts associated with events outside the rate case in forecasting income tax expenses for ratesetting purposes. Circumstances under which a utility has not paid federal taxes for over a decade and state taxes for over a GRC cycle constitute such extraordinary circumstances that would warrant an alternative method.[1564]

SCE has asserted in its testimony that due to alternative minimum tax requirements under the Inflation Reduction Act, it will be a cash taxpayer for federal taxes during this GRC cycle.[1565] SCE also asserts that it expects to be a cash state income taxpayer during the 2025 GRC cycle.[1566] However, SCE appears to misunderstand TURN's proposal when it states that "TURN suggests that working cash should be adjusted during the remaining GRC cycle if SCE ends up paying lower estimated taxes than forecast."[1567]

TURN's proposal simply recommends that the Commission hold SCE to its word. Should SCE fail to owe cash federal and state taxes *again* during the 2025 GRC, SCE's proposed federal and state income tax lags of 54 days and 40 days respectively would continue to be unreasonable. Consequently, TURN proposes that the working cash allowance should be adjusted prospectively if this is the case. TURN notes that the tax lag associated with taxes represents a significant portion of SCE's working cash request. The difference in working cash

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[1564] D.21-08-036, p. 501.

[1565] Ex TURN-02, p. 29., citing Ex. SCE 07 Vol 2., p. 39

[1566] Ex TURN-02, p. 29., citing Ex. SCE 07 Vol 2., p. 39

[1567] Ex. SCE 18 Vol. 02A., p. 24 citing Ex. TURN-02., p. 30.

requirements based on Cal Advocate's proposal which assumes no cash payment of federal taxes (365-day lag) and significantly lower than statutory levels of California state taxes (328.5-day lag) versus SCE's amended forecast (based on a 54 day federal tax lag, and a 40 day state tax lag) is $447.262 million annually.[1568] Relative to SCE's opening testimony of $1.223 billion, this adjustment in taxes represents more than one third[1569] of the total request. Should SCE continue its trend of owing no taxes into the 2025 GRC cycle contrary to its assertions, TURN believes that this would constitute an extraordinary circumstance of the kind contemplated by OII 24. As such, it would certainly warrant an alternative method for determining the appropriate working cash allowance for the remaining years of the rate case cycle. Should this prove to be the case, the Commission would be remiss not to prospectively adjust the authorized working capital to reflect a federal tax lag of 365 days and a state tax lag of 290 days consistent with SCE owing no cash taxes due.

39.3 Customer Deposits

The Commission has consistently treated SCE's customer deposits as a source of permanent working capital as an offset to rate base since SCE's 2003 GRC.[1570] In the 2012, 2015, 2018, and 2021 GRCs, SCE asked the Commission to reject this policy as it does again in this GRC.[1571]

[1568] Ex SCE 18 Vol 02, p. 24, Table III-11 (Taxes Based on Income Summary of Lag Days Proposals)

[1569] $447.262/$1,223 million =36.6%

[1570] Ex TURN-02, p. 30, citing D.15-11-021 (SCE 2015 GRC), p. 470.

[1571] D.15-11-021, pp. 470-471, D.12-11-051 (SCE 2012 GRC), pp. 627-628.

SCE continues to argue that other utilities have different treatment for their customer deposits. However, as SCE itself points out, the Commission has "treated customer deposits inconsistently among the large utilities."[1572] Furthermore, in D.04-07-044 (SCE's 2003 GRC), the Commission explicitly addressed the applicability of SP U-16 to the treatment of customer deposits, stating that "as the Commission previously held, U-16 is only a guide, and deviations are appropriate where circumstances warrant."[1573] TURN does not believe it is appropriate that SCE be allowed to pick and choose its "preferred treatment."[1574] While SCE's customer deposits have declined, even at the lowest forecast value recommended by TURN, they represent a significant source of working capital which does not have to be provided by other investors.

In this GRC, SCE argues that the Commission's treatment of its customer deposits as a permanent source of working capital is predicated on Commission comments that the SCE's customer deposits have remained high and stable over time.[1575] SCE appears to indicate that the reduction in customer deposits during Covid is a reason the Commission should change its historical treatment in this GRC. However, customer deposits continue to provide a significant portion of working capital for SCE. SCE's own forecasts project customer deposit to increase toward the end of this GRC cycle, with annual averages exceeding the 2023 levels by 2027 and reaching a high of $197 million in 2028.[1576] In recognition of the unusual circumstances of Covid and recovery in its aftermath, TURN recommended that the Commission maintain its

[1572] Ex SCE 18 Vol 02, p. 30.

[1573] D.04-07-044, p. 253.

[1574] Ex SCE 18 Vol 02, p. 31.

[1575] Ex SCE 18 Vol 02, p. 32.

[1576] Ex TURN-02, p. 32., citing TURN DR 089 and Ex SCE 07 Vol. 02, p. 49.

treatment for SCE's customer deposits and adopt the value of $174 million, which represents the *lowest* annual level of customer deposits held as projected by SCE.[1577] Thus, adopting the $174 million value would represent the most conservative approach to estimating the amount of customer deposits held by SCE throughout this GRC period.

Hence, the Commission should maintain its longstanding practice and treatment of SCE's customer deposits and adopt $174 million as an offset to rate base.

39.4 Taxes

40. SCE ASSET DEPRECIATION STUDY

SCE seeks a $313 million increase to its authorized depreciation expense for test year 2025, calculated based on year-end 2022 plant balances (a 14% increase).[1578] Of this amount, $294 million is for depreciation of transmission and distribution assets, and represents the combined impact of SCE's proposed $212 million increase for net salvage costs, with an additional $82 million increase resulting from SCE's proposed service lives for those assets.[1579]

TURN's testimony regarding these accounts continues to rely on the analytical methods used in recent GRCs where the Commission generally or entirely adopted outcomes consistent with TURN's recommendations. TURN's recommended net salvage rates include adjustments consistent with the principle of "gradualism," just as was the case in SCE's test year 2021 GRC

[1577] Ex TURN-02, p. 32.

[1578] Ex. TURN-16 (Prepared Testimony of David Garrett), pp. 5-6. The dollar figures discussed here as well as those set forth in TURN's depreciation testimony are based on plant balances as of December 31, 2022. This permits a direct comparison to the depreciation accruals presented in SCE's depreciation study, which was also based on plant balances as of December 31, 2022. The actual depreciation expense for the 2025 test year will reflect the adopted depreciation rates applied to the authorized plant balance for 2025, and will be higher to the extent the 2025 plant balances are higher than the end-of-year 2022 figures.

[1579] Ex. SCE-18, Vol. 3, p. 1, Table I-1.

when the Commission adopted TURN's net salvage recommendations in all disputed accounts. And TURN's recommended average service lives are based on a straightforward analysis without any need to rely on "statistically aged" or otherwise simulated data, just as was the case in PG&E's test year 2023 GRC when the Commission adopted TURN's service life recommendations in very nearly all disputed accounts.[1580]

The Commission should limit any increase in depreciation expense to no more than is recommended in TURN's testimony and presented in this brief, based on the evidentiary record developed in this proceeding. TURN's proposed net salvage rates for SCE's transmission and distribution accounts are consistent with the Commission's commitment to "gradualism" in this area. TURN's proposed service live for several of the transmission and distribution plant accounts are more reasonable in light of the utility's recorded retirement data. The combined impact of TURN's positions and recommendations is a $71.6 million increase as compared to the currently authorized depreciation parameters.[1581]

40.1 T&D Net Salvage

For a large number of its T&D mass property accounts, SCE proposes net salvage rates that are substantially more negative and thus lead to higher depreciation rates, all else equal. The utility's proposed changes to net salvage rates for T&D accounts would result in $212 million of

[1580] TURN wishes to be clear that this brief's discussion of the topics of net salvage rates and average service lives is to varying degrees something of a cut-and-paste of briefs TURN submitted in each of these two relatively recent GRC proceedings. This approach seemed particularly appropriate where, as here, the utility's rebuttal testimony largely cut-and-pasted material from rebuttal testimony submitted on net salvage issues in the test year 2021 SCE GRC, and on average service life issues in the test year 2023 PG&E GRC. An obvious difference between the two approaches is that TURN is relying on material consistent with the outcomes the Commission adopted in those earlier proceedings.

[1581] Ex. TURN-18, p. 6.

increased annual depreciation accrual (based on 2022 year-end plant balances).[1582] TURN's depreciation analysis relied on the Commission's past commitment to "gradualism" and recommended smaller changes to the currently authorized net salvage rates.

40.1.1 General Principles of Net Salvage

The "net salvage rate" for a particular plant account represents the combined effect of the "gross salvage" the utility might obtain from an asset at the end of its useful life, and the "cost of removal" associated with removing the asset from service. For nearly every T&D mass property account of SCE, the net salvage rate is a negative figure, because the cost of removing the assets from service is expected to exceed the gross salvage value. When a negative net salvage rate is applied to the plant balance in an account to calculate the depreciation rate, it results in increasing the total depreciable base to be recovered over a particular period of time and, by extension, increases the depreciation rate. Therefore, a greater negative net salvage rate equates to a higher depreciation rate and expense, all else held constant.[1583]

Net salvage rates are calculated by determining gross salvage and removal costs at the time of retirement as a percent of the original cost of the assets retired. In other words, salvage and removal costs are based on current dollars (when the assets are removed from service), while retirements are based on historical dollars, reflecting uninflated cost figures from years, and often decades earlier. Increasing labor costs associated with asset removal combined with the fact that original costs remain the same have contributed to increasing negative net salvage over time.[1584]

[1582] Ex. SCE-07, Vol. 03, p. 2, Table I-1.

[1583] Ex. TURN-16 (Garrett), pp. 34-35.

[1584] *Id.*, p. 35.

40.1.2 TURN's Net Salvage Recommendation – The Commission Should Limit Increases Consistent With The "Gradualism" Employed In Recent GRC Decisions.

In PG&E's test year 2014 GRC, the Commission expressed concern over the increasing negative net salvage values reported by the utilities, and the impact the resulting requests for increased depreciation expense could have on the utility's customers.[1585] To mitigate the impact on the utility's rates, the Commission there described and relied on the concept of "gradualism":

> In evaluating whether a proposed increase reflects gradualism, however, we believe the more appropriate measure is how the change affects customers' retail rates. The fact that PG&E previously proposed higher removal costs than adopted has no bearing on how a proposed change would impact current ratepayers. Accordingly, we apply the principle of gradualism based on how a proposed change in estimate compares to adopted costs reflected in current rates, irrespective of what PG&E may have forecasted in an earlier depreciation study.[1586]

To achieve an outcome consistent with "gradualism," the Commission's general approach was to "adopt no more than 25% of PG&E's estimated increases in the accrual provisions for removal costs," in order to "temper[] the impacts on current ratepayers."[1587]

Since the PG&E 2014 GRC, in GRCs where the Commission has seen fit to modify net salvage values at all for the major energy utilities, it has limited any changes to no more than 25% of the estimated increase produced by the utility's depreciation study.

Most recently, in PG&E's 2023 GRC, the company proposed negative salvage rate increases for several of its distribution and transmission plant accounts. In response, TURN proposed the Commission limit the net salvage rate increases to no more than 25% of the increase requested by the utility, consistent with the Commission's policy regarding

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[1585] D.14-08-032 (PG&E test year 2014 GRC), p. 597.

[1586] *Id*. at 598.

[1587] *Id.*, at 602.

gradualism.[1588] The Commission found that "PG&E's proposed net salvage values are inconsistent with principles of gradualism"[1589] and instead adopted TURN's estimates of net salvage percentages for the accounts in dispute.[1590]

Gradualism has been a consistent element of the Commission's decisions in recent SCE GRC proceedings, with one exception where the Commission authorized no change to existing depreciation rates. In the test year 2021 GRC decision for SCE, the Commission stated that it had applied the gradualism principle in adopting net salvage rates in SCE's 2015 GRC, and continued to endorse the concept for the 2021 GRC cycle, limiting net salvage increases to 25% of SCE's requested increases.[1591]

SCE's depreciation study proposes increased (that is, more negative) figures for the net salvage rates for twelve T&D accounts, as addressed in TURN's testimony.[1592] There appears to be no mention in the utility's direct testimony of the concept of "gradualism" as applied to the utility's net salvage analysis here, or any recognition that the Commission had relied on "gradualism" in adopting net salvage values in several of SCE's most recent GRCs.[1593] While TURN's study concluded that SCE's net salvage rates warranted some movement in the direction requested by the utility, TURN's proposed adjustments are based on the 25% cap originally described in the PG&E 2014 GRC decision, and reaffirmed in the more recent GRC

[1588] D.23-11-069 (in PG&E TY 2023 GRC), p. 672, Table 10-D.

[1589] *Id*.

[1590] *Id*. at 674-675.

[1591] D.21-08-036 (in SCE TY 2021 GRC), p. 512.

[1592] Ex. TURN-16, p. 8, Figure 3.

[1593] SCE's depreciation study mentions "gradualism" several times in the context of its average service life proposals, where application of the principle might limit reductions that could otherwise be made to depreciation rates.

decisions: For each account for which SCE proposed a more negative net salvage rate, TURN's adjustments limit the change to 25% of the utility's estimated increase. SCE calculates TURN's recommended net salvage rates would produce a $52.4 million increase in the annual depreciation expense when viewed in isolation.[1594]

40.1.3 After Ignoring the Concept of Gradualism In Its Depreciation Study, SCE Raised Oft-Rejected Or Baseless Arguments Against It in Rebuttal.

Coming into this GRC, SCE should have been well aware of the Commission's recent practice of applying the concept of "gradualism" in setting the level of reasonable net salvage increases where the Commission has determined that higher net salvage rates of any amount are warranted. In the utility's test year 2021 GRC, the Commission's discussion of net salvage rates concluded with the following:

> We continue to endorse the concept of gradualism with respect to net salvage rates for this rate case cycle given that the overall cost increases at issue in this GRC (for both Track 1 and Track 2) are substantial and ratepayers are facing a great deal of economic uncertainties associated with the global COVID-19 pandemic. [cites omitted] Even SCE recognizes that its requested net salvage rate increase is significant. [citing SCE's rebuttal testimony]. In consideration of these factors and consistent with past Commission precedent, we find it reasonable to limit any net salvage increases to 25 percent of SCE's requested increases.[1595]

And in SCE's test year 2018 GRC, the utility itself proposed a cap on its proposed net salvage rate increases in the name of such "gradualism." However, the Commission found such "little merit" in the net salvage elements of SCE's depreciation study that it declined to apply the

[1594] Ex. SCE-18, Vol. 3, p. 3, Table II-2.

[1595] D.21-08-036 (SCE TY 2021 GRC), p. 512.

concept of gradualism under the circumstances, and instead retained the then-authorized rates without any increase as the more reasonable outcome.[1596]

Here, SCE made no mention of "gradualism" in the net salvage portion of its depreciation study,[1597] and instead proposed increased net salvage rates that, if adopted, would result in an annual depreciation expense increase of $212 million when applied to 2022 plant balances (which would translate to a correspondingly larger increase if applied to authorized 2025 plant balances).[1598] TURN submits that the Commission's response to SCE's near-identical showing in support of the requested $212 million increase here should be the same as was adopted in the prior GRC when the utility's requested increase was $199 million; it should "instead find reasonable the consistent approach set forth in TURN's proposal."[1599]

40.1.3.1 SCE's Ongoing Claims Of Deficient Depreciation Rates Continue To Be Inadequately Supported.

SCE has a longstanding practice of raising arguments regarding the purported deficiency of previously-adopted depreciation rates, arguments the Commission has regularly and uniformly rejected or chosen to leave unmentioned in past GRC decisions. SCE's arguments are based on its assumption that the amounts it has recorded as cost of removal, as well as its past and present proposals for depreciation accruals and calculations of future costs of removal, together represent a sacrosanct truth regardless of what the Commission has said about them in past decisions. And anything that would result in depreciation accruals at a level less than the utility has requested,

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[1596] D.19-05-020 (SCE test year 2018 GRC), pp. 314 and 319.

[1597] Ex. SCE-07, Vol. 3, pp. 13-65.

[1598] Ex. SCE-18, Vol. 3, p. 1, Table I-1.

[1599] D.19-05-020, pp. 508 and 512.

whether here or in prior GRCs, represents a "deficit" that the utility finds compelling but the Commission has never embraced. For example, SCE contends that the adopted net salvage rates in recent GRCs "have been set below the levels justified in corresponding depreciation studies."[1600] But according to those GRC decisions, the Commission adopted net salvage rates at the levels determined to be reasonable given an evidentiary record that consisted not only of SCE's depreciation study, but material establishing the fundamental flaws of that study. In SCE's test year 2012 GRC, the utility claimed that its accumulated depreciation balance as of the end of 2009 should be $2.7 billion higher than it was because previously authorized depreciation rates have not kept pace with removal costs, and sought a depreciation expense increase of $59 million per year to address the purported deficit (in addition to the increase of $511 million from the utility's proposed changes to depreciation parameters).[1601] The Commission dismissed SCE's contention as relying on a self-fulfilling prophecy of the utility's own making:

> Regarding documentation of the accumulated depreciation deficit, SCE's basis to change its rates, we recall the function of the reserve is to allocate cost recovery for the cost of installation and removal of a group of assets over the service life. The Commission previously adopted depreciation rates and service lives, and SCE has made the resulting cost allocations. The calculated "deficit" is the mathematical difference between what SCE asked for and what was authorized by the Commission.[¶] On the other hand, slightly different assumptions would significantly influence the sufficiency of the accumulated depreciation reserve. Thus, SCE's deficit argument is self-fulfilling because it presumes that its assumptions in prior GRC requests were correct, including constant escalation of COR, even though some assumptions were not adopted by the Commission or borne out by actual retirements. [¶] For purposes of this GRC, we do not determine whether the $2.7 billion claimed deficit is an accurate number.[1602]

[1600] Ex. SCE-18, Vol. 3, p. 4. SCE made the identical argument in its rebuttal testimony in the test year 2021 GRC. Ex. TURN-117, p. 5.

[1601] D.12-11-051 (SCE TY 2012 GRC), pp. 658-659.

[1602] *Id.*, pp. 671-672.

SCE made a similar claim in its TY 2015 GRC, and the Commission had a consistent response:

> Generally, SCE argues that its currently authorized depreciation rates are too low, thus shifting costs from current customers to future customers. SCE claims that its depreciation proposals reduce, but do not eliminate this cost shifting, while the TURN and ORA proposals would exacerbate it. As we noted in the last GRC decision, SCE's calculations of past depreciation "deficits" and ongoing or future "deferrals" are merely calculations reflecting the difference between SCE's proposals for depreciation parameters and Commission-adopted or party-proposed parameters. SCE's point that if ongoing depreciation expense is "too low," future customers will be required to pay more may be valid. However, we recognize that determining the "right" level of depreciation expense is a complex exercise of forecasting future costs and events. SCE's calculations of deficits and deferrals are only valid if we assume that SCE's past and present proposals are correct. We do not start with this assumption; instead, we remind SCE that it bears the burden of proof that its proposals are reasonable.[1603]

The Commission continues to have good reason to be dubious of SCE's recorded net salvage figures. The utility reports 5-year and 10-year averages for net salvage rates for some of its largest distribution plant accounts that, if they are to be taken at face value, suggest the Commission should expect that it would cost from three to nearly ten times as much to remove the plant in service than it originally cost to install the plant.[1604] And while SCE describes the cost of removal values as "recorded costs," the largest part of those recorded costs are the product of an allocation of the total costs of the underlying plant replacement project.[1605] In this way, SCE has substantial control over the amounts that it is reporting as "recorded" costs of

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[1603] D.15-11-021 (SCE TY 2015 GRC), pp. 394-395 (footnote citations omitted).

[1604] Ex. WP-SCE-07, Vol. 3, pp. 69 (for Account 364) and 90 (for Account 369). The -333% and -407% figures reported as the 5-year and 10-year average for Account 364 (Distribution Poles) indicate net salvage cost (primarily the cost of plant removal at the end of its life) of 3.3 to 4 times the original plant cost. For Account 369 (Services), the -972% and -696% averages indicate net salvage cost of 7 to nearly 10 times the original plant cost. For Account 364, SCE's recorded figures for cost of removal have exceeded -500% in five of the past ten years.

[1605] D.15-11-021 (SCE TY 2015 GRC), pp. 412-413.

removal or net salvage costs. And these "recorded" costs are the fodder of its ongoing dire predictions of the consequences that would follow should the Commission fail to authorize increases in the amounts SCE requests.

40.1.3.2 SCE Falls Short with its Attempts To Illustrate The Inadequacy Of The Depreciation Rates Found Just and Reasonable in Past GRCs.

In its rebuttal testimony, SCE describes the GRC outcomes since 2009 as suggesting a pattern of the Commission adopting longer service lives while "looking skeptically at proposed increases to net salvage rates," resulting in lower overall depreciation rates "even if a gradual aggregate increase was warranted." But the associated figure in the utility's rebuttal illustrates that over the same period, SCE itself proposed a lower overall depreciation rate as compared to the overall then-authorized rate from the 2009 GRC to the 2018 GRC, and the requested amount for 2021 was the second-lowest of the five GRCs.[1606] In other words, SCE is criticizing the Commission for failing to authorize an increased overall depreciation rate in prior GRCs, even though SCE itself did not seek an increased overall depreciation rate. Furthermore, if the record in those prior proceedings convinced the Commission that it would be reasonable to adopt longer service lives, but left the agency unconvinced of the reasonableness of SCE's proposed net salvage changes, the utility should not now try to pin the blame for that on the Commission.

SCE's rebuttal testimony also includes an attempt to illustrate that adoption of longer service lives along with "stagnated net salvage rates [has led] to a growing and distressing gap between recorded costs and GRC-authorized costs for net salvage."[1607] Again, the "recorded"

[1606] Ex. SCE-18, Vol. 3, pp. 5-6 and Figure II-1.

[1607] Ex. SCE-18, Vol. 3, pp. 7-8 and Figure II-2.

costs are the SCE-produced figures the Commission did not adopt, whereas the GRC-authorized costs are the figures the Commission found reasonable based on the record of each of the GRCs reflected in SCE's graphic. And the illustration is telling, but not at all in the manner SCE suggests. From the 2009 GRC through the 2021 GRC, the SCE-proposed average service lives increased by approximately 25% overall (from 39 years to 50 years), while its 10-year average "recorded" figures for net salvage rates increased by approximately 80% (from -80% in 2009 to -145% in 2021). The GRC authorized net salvage rates increased by approximately 33% (from -54% to -72%) during that same period. TURN submits that SCE's table raises far more troubling questions about the pattern displayed by its "recorded" net salvage figures over this period than it does about the reasonableness of the Commission-adopted outcomes.

Similarly, the comparison SCE makes between "unit costs" in this context actually demonstrates the reverse of the utility's apparent point.[1608] Here the comparison is between SCE's 2025 GRC version of the table and the 2021 GRC version.[1609] In the 2021 GRC, SCE calculated a unit cost based on its purported "Recent Cost to Remove," and compared it to a unit cost based on the "Authorized COR" (that is using 2018 GRC-authorized figures), and "TURN Proposed" and "SCE Proposed." SCE's calculations purported to show that the "Authorized COR" and "TURN Proposed" amounts were uniformly less than the "Recent Cost to Remove" for each of the four distribution accounts the utility selected. The 2025 GRC version of the table shows marked improvement, even though the "Authorized COR" increased not by the amount SCE sought, but the gradualism-tempered amount proposed by TURN. That is, the SCE-calculated difference between its Recent Cost to Remove" and the Authorized COR unit cost figures was substantially

[1608] Ex. SCE-18, Vol. 3, p. 9, Table II-3.

[1609] Ex. TURN-117 (SCE TY 2021 GRC Depreciation Rebuttal Excerpt), p. 11, Table II-3.

less in the 2025 GRC calculations than they were in the 2021 GRC calculations.[1610] To be clear, TURN does not in any way agree that SCE's underlying calculations of its "Recent Cost to Remove" is valid. But by the utility's own calculations, even with the net salvage value increases adopted in 2021 being limited by gradualism, those increases significantly closed the gap. No doubt, the net salvage values adopted under gradualism may not have closed the gap as much as SCE would prefer. But a comparison of the two tables leaves no doubt that, even with gradualism being consistently applied, the movement is in the direction of greater depreciation accruals.

40.2 T&D Average Service Life

40.2.1 TURN's Analysis And Recommendations Are Firmly Based On SCE's Retirement Data and Produce Reasonable Curves and Lives.

TURN's recommended service lives are the product of a straightforward analysis that relies on the objective data recorded by SCE (rather than simulated data), and the employment of mathematical and visual curve fitting and expert judgment to derive a reasonable Iowa curve for each of the accounts in dispute.[1611] TURN proposes service life adjustments to seven of SCE's transmission and distribution accounts. TURN's service life analysis relied upon the "retirement rate method," the most common actuarial method used by depreciation analysts. The retirement rate method is ultimately used to develop an observed life table (OLT) which shows the percentage of property surviving at each age interval, yielding a pattern of property retirement described as a "survivor curve."

[1610] For Account 365 (Overhead Conductor), the difference declined from $1.70 to $0.13; for Account 366 (Overhead Conduit), the difference declined from $7.32 to $2.94; for Account 367 (Underground Conductor), the difference declined from $5.61 to $3.98; and for Account 368 (Transformers), the difference declined from $837 to $212.

[1611] Ex. TURN-16 (Testimony of David Garrett), pp. 11-19.

Since the retirement data for an account typically does not provide a smooth or complete curve, the depreciation witness selects an Iowa curve to complete the curve-fitting process and to derive a recommended service life for each account.[1612] TURN's analysis used the aged property data provided by SCE to develop an OLT curve for each transmission and distribution plant account, then engaged in a curve-fitting process to select the Iowa curve that best fit the OLT curve. For the curve-fitting, TURN's analyst relied upon a combination of visual and mathematical techniques, as well as relying on his professional judgment. He first reviewed the OLT curve data to ensure the analysis reflected the more reliable data, without irregularities or erratic shifts. He then applied a mathematical curve-fitting technique to get an objective, mathematical assessment of how well the curve fits, and observed the OLT against potential Iowa curves in order to determine how well the curve fits visually. This process might be repeated several times for any given account in order to ensure that the most reasonable Iowa curve is selected.[1613]

TURN's curve selection process does not rely exclusively on any single step of this analysis. For example, while mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results, TURN's analyst recognized it may not always yield the optimum result. Similarly, not every portion of the OLT curve should be given equal weight. Often the "tail end" of a curve may have less analytical value that other portions of the curve, and should be given less weight. The fitting process therefore focuses not only on

[1612] TURN's testimony included a more detailed explanation of how the Iowa curves are used in the actuarial analysis. Ex. TURN-16 (Garrett), Appendix C.

[1613] Ex. TURN-16 (Garrett), pp. 11-13.

the entire OLT curve, but also the portion that presented the most significant part of the curve for certain accounts.[1614]

TURN's curve selection also does not rely on simulated data produced by SCE's "statistical aging" process. As explained in TURN's testimony, SCE maintains what is known as "aged data," which means a record is kept of the vintage year of a retired asset so that the age is known. In this case, SCE has aged retirement experience available dating back to 2002. That is, the utility's actual recorded retirement experience dating back to 2002 are real data, based entirely in fact. In the opinion of TURN's expert witness, twenty years of retirement experience data is sufficient for actuarial analysis without the need to supplement the data.[1615] In PG&E's 2023 GRC, the Commission agreed, as it adopted nearly all of TURN's proposed service lives based on an analysis using only the 22 years of actual recorded retirement experience data, rather than the "statistically aged" data PG&E had presented in that case.[1616]

The following sections summarize TURN's showing on each of the seven accounts for which TURN proposes a life-curve that is different than SCE's proposal for the account.

40.2.1.1 Account 352 (Structures and Improvements)

TURN recommends a curve of R1-67, whereas SCE recommends R2-60.[1617] For this account, the graph in TURN's testimony illustrates that the R1-67 curve TURN selected results in a closer fit to the OLT than does SCE's selected curve, and includes a truncation line demarking the point at which the data points in the OLT become less relevant. For mathematical

[1614] *Id.*, pp. 13-14.

[1615] *Id.*, pp. 15-16.

[1616] D.23-11-069 (PG&E TY 2023 GRC), p. 670, Table 10-C.

[1617] Ex. TURN-16 (Garrett), pp. 19-21.

curve fitting, the sum-of-squared-differences (SSD) is 5.9040 for SCE's proposed curve, but 2.0254 for TURN's, indicating the R1-67 curve is a better mathematical fit with SCE's historical data. The Commission should adopt the R1-67 curve as proposed by TURN.

40.2.1.2 Account 354 (Towers and Fixtures)

TURN recommends a curve of R4-76, whereas SCE recommends R5-70.[1618] For this account, the graph in TURN's testimony illustrates that the R4-76 curve TURN selected results in a closer fit to SCE's OLT than does SCE's selected curve. For this account, TURN's witness applied his judgment to select a reasonably well-fitting curve rather than the best-fitting curve, as the latter would likely result in an unreasonably long life estimate. Nonetheless, this does not mean the data are irrelevant, particularly when SCE has not presented any compelling evidence outside the statistical data to support its proposed service life for this account. Both TURN's and SCE's proposed curves suggest an increase in the retirement rate going forward, but the R4-76 curve TURN recommends gives more credit to SCE's observed data. For mathematical curve fitting, the sum-of-squared-differences (SSD) is 0.3489 for SCE's proposed curve, but 0.1418 for TURN's, indicating the R4-76 curve is a better mathematical fit with SCE's historical data. The Commission should adopt the R4-76 curve as proposed by TURN.

40.2.1.3 Account 356 (Overhead Conductors and Devices)

TURN recommends a curve of R2.5-74, whereas SCE recommends R3-65. The R2.5-74 curve results in a good balance between giving due credit to the actual retirement experience in this account while being conservative to ensure the service life estimate is not unreasonably long.

[1618] *Id.*, pp. 22-24.

If future depreciation studies indicate a shorter average service life, then life estimates can be adjusted accordingly. TURN's proposed curve again achieves a better mathematical fit to the OLT curve (an SSD of 2.0645 for SCE's, and 0.7608 for TURN's).[1619] The Commission should adopt the R2.5-74 curve as proposed by TURN.

40.2.1.4 Account 357 (Transmission Underground Conduit)

TURN recommends a curve of R4-61, whereas SCE recommends R4-55. Again, the R4-61 curve results in a good balance between giving due credit to the actual retirement experience in this account while being conservative to ensure the service life estimate is not unreasonably long. TURN's proposed curve again achieves a better mathematical fit to the OLT curve (an SSD of 0.0963 for SCE's, and 0.0182 for TURN's).[1620] The Commission should adopt the R4-61 curve as proposed by TURN.

40.2.1.5 Account 366 (Distribution Underground Conduit)

For Account 366, TURN recommends a curve of R2.5-66, whereas SCE recommends R3.0-60. The graph included in TURN's testimony shows the vast majority of this OLT curve is statistically relevant. Both of the selected Iowa curves provide relatively close and similar fits to the OLT curve through age 40. After that point, the higher mode of SCE's selected R3 curve (i.e., a less flattened trajectory) causes it to diverge from the OLT curve relative to the lower-mode of the R2.5 Iowa curve TURN recommends. Since SCE has not presented any meaningful evidence beyond its historical retirement data for this account, then an estimated average life of

[1619] Ex. TURN-16 (Garrett), pp. 24-26.

[1620] Ex. TURN-16 (Garrett), pp. 26-28.

66 years is more supported by the evidence. TURN's proposed curve again achieves a better mathematical fit to the OLT curve (an SSD of 0.1535 for SCE's, and 0.0392 for TURN's).[1621] The Commission should adopt the R2.5-66 curve as proposed by TURN.

40.2.1.6 Account 367 (Underground Conductors and Devices)

TURN recommends a curve of L1-50, whereas SCE recommends R1.5-45. TURN's testimony explained that both recommended curves result in relatively close fits to the OLT curve and are both within a reasonable range for this account. TURN's proposed curve again achieves a better mathematical fit to the OLT curve (an SSD of 0.0239 for SCE's, and 0.0054 for TURN's).[1622] The Commission should adopt the L1-50 curve as proposed by TURN.

40.2.1.7 Account 369 (Services)

TURN recommends a curve of R2.5-62, whereas SCE recommends R2-55. For this account, there is a more pronounced difference between the OLT curve reflecting SCE's actual retirement experience, which TURN relied upon, and the OLT curve to which SCE has added its statistically aged data to its actual retirement experience. The graph in TURN's testimony illustrates that the R2.5-62 curve is a much closer fit with SCE's actual retirement experience. This is confirmed by the mathematical fitting process, as SCE's proposed curve results in an SSD of 0.4946, while TURN's results in an SSD of 0.0711.[1623] The Commission should adopt the R2.5-62 curve as proposed by TURN.

[1621] Ex. TURN-16 (Garrett), pp. 28-30.

[1622] Ex. TURN-16 (Garrett), pp. 30-32.

[1623] *Id.*, pp. 32-34,

40.2.2 The Criticisms Raised in SCE's Rebuttal Lack Adequate Evidentiary or Analytical Support.

40.2.2.1 SCE's Defense of its Use of Statistically-Aged Data Misses the Point – Reliance on Recorded Data Should be Preferred over Reliance on Statistically-Aged Data.

This is the first case in which SCE has proposed to use statistically-aged data.[1624] According to the utility, it faced two choices – rely on 20 years of recorded aged data (from 2002 through 2021), or use statistically aged data for retirements prior to 2002.[1625] The difference between the two is that "SCE's recorded data" from 2002 forward includes the recorded vintage years, while that information does not exist on a recorded data for pre-2002 retirements.[1626] SCE argues that its process is not one of manufacturing data, because "[t]he recorded retirements in the statistically aged data are the retirement amounts recorded on SCE's books."[1627] But the retirement amounts for the pre-2002 data do not include "recorded vintage years."[1628] After the statistical aging process, the pre-2002 data DOES include such information, as statistical aging serves to "assign vintage years to data prior to 2002 in order to be included in the study."[1629] The vintage year data for pre-2002 plant did not exist prior to the statistical aging process deployed by SCE's consultant, but did exist after that process.

SCE appears to believe that the Commission should find that the utility's first-time reliance on simulated data here is reasonable because <u>PG&E</u> included such data in its 2017 GRC,

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[1624] Ex. SCE-18, Vol. 3, p. 35.

[1625] *Id.*, p. 34.

[1626] *Id.*, p. 36.

[1627] *Id.*

[1628] *Id.*

[1629] *Id.*, p. 33.

and TURN raised no objection to the practice then.[1630] The Commission should disregard such arguments. The fact that neither TURN nor any other party addressed the issue of PG&E's reliance on simulated data in an earlier GRC cannot reasonably be interpreted as assent to that method; the unfortunate truth is that in a proceeding of the breadth of a PG&E GRC, there are likely numerous issues that are simply missed by intervenors despite their best efforts.

Besides, one would think the more recent history on the topic is more relevant. SCE's depreciation testimony fails to mention that when the utility's witness earlier appeared as PG&E's depreciation witness in that utility's most recent 2023 GRC, TURN raised extensive objections to the PG&E's reliance on simulated data. The final decision in that GRC did not squarely address the merits of that specific dispute, but it strongly implied skepticism when it cited the concerns TURN had raised about PG&E's pre-1999 data (the period for which PG&E relied on statistical aging) and noted with favor that TURN had used "more recent experience bands" (that is, those bands that did not contain pre-1999 data) in developing its recommendations, which the Commission adopted for all but three of the accounts in dispute.[1631]

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40.2.2.2 Twenty Years of Recorded Data are Sufficient.

SCE argues that its reliance on statistically aged data is necessary to enable reliance on "many more decades of data" rather than the 20 years of historical data available to the

[1630] *Id.*

[1631] D.23-11-069 (PG&E TY 2023 GRC), pp. 669-670. The Commission adopted TURN's recommendation for twelve of the fourteen plant accounts for which TURN addressed the proposed Average Service Life in PG&E's GRC.

utility.[1632] But the Commission had recently found reasonable TURN's application of only the more recent experience bands to fit survival curves in the PG&E GRC, rather than using simulated data through statistical aging in order to create longer experience bands.[1633] TURN's expert witness here testified that, in his experience, 20 years of retirement experience data is sufficient for actuarial analysis without the need to supplement the data.[1634] SCE's rebuttal testimony has made no attempt to explain why the 22 years of historical data would be sufficient for the development of average service lives for the majority of the accounts in dispute in the PG&E GRC, but 20 years should be found inadequate for SCE GRC purposes. Nor does SCE explain why it deems the $3.0 billion of T&D asset retirements (representing "millions of assets") experienced in the 10- year period from 2012-2021 a "reasonable basis for estimating future net salvage costs,"[1635] but 20 years is inadequate for development of average service lives in the same depreciation study. The Commission should find that 20 years is indeed sufficient for purposes of setting average service lives in this GRC, consistent with the outcome recently adopted in the test year 2023 PG&E GRC.

[1632] Ex. SCE-18, Vol. 3, p. 33. SCE's rebuttal testimony refers to the data in the "2002-2021 experience band" as reflecting either 19 years or 22 years of data. *Id.*, pp. 34 (19 years) and 33 and 37 (22 years). The 19-year figure is a miscalculation – the period 2002-2021 encompasses 20 years, consistent with how PG&E's rebuttal testimony in its test year 2023 GRC calculated the 1999-2020 experience band as representing 22 years of data. The 22 years figure as it appears in the SCE GRC rebuttal appears to be a failure on the part of SCE's witness to make that correction when he cut-and-paste material from his PG&E GRC rebuttal for purposes here. *See, for example,* Ex. SCE-18, Vol. 3, p. 37, lines 1-19, and Ex. TURN-105 (Excerpt from PG&E Rebuttal Testimony from test year 2023 GRC), pp. 12-74, l. 22 to 12-75, l. 22.

[1633] D.23-11-069 (PG&E TY 2023 GRC), p. 669.

[1634] Ex. TURN-16, p. 16.

[1635] Ex. SCE-07, Vol. 3, p. 19.

40.2.2.3 The Role of Gradualism in Setting ASLs

SCE's rebuttal testimony argued that TURN had failed to apply the concept of "gradualism" to its service lives recommendations, whereas the utility had limited its proposed average service lives "more than five years in either direction."[1636] This portion of SCE's argument is, largely a "cut-and-paste" from PG&E's rebuttal testimony in that utility's test year 2023 GRC, where PG&E had the same witness addressing its service life proposals.[1637] If SCE saw fit to repeat here its argument from the prior GRC, the utility should also have indicated how the Commission resolved the disputed issue there. As noted earlier, in the 2023 GRC, the Commission adopted TURN's proposed average service life figures for twelve of fourteen accounts. And it did so even as it "confirm[ed] its interest in maintaining a gradual approach to changes in depreciation, which must be driven by specific aging analyses."[1638] The 2023 GRC decision includes a table comparing the then-current curve and the TURN-proposed curve the Commission adopted as reasonable.[1639] For the eight electric plant accounts, half reflect increased lives of more than 5 years, and seven reflect increased lives of 9-16% when calculated as a percentage of the then-current life. The Commission should find SCE's argument as lacking in support as it did in the PG&E GRC, and instead find again that TURN's proposed service lives are consistent with maintaining a gradual approach to changes in depreciation.

[1636] Ex. SCE-18, Vol. 3, pp. 29-30.

[1637] Ex. TURN-105 (Excerpt from PG&E Rebuttal Testimony from test year 2023 GRC), pp. 12-25 to 12-27.

[1638] D.23-11-069 (PG&E TY 2023 GRC), pp. 669-670 [citations omitted].

[1639] *Id.*, p. 670, Table 10-C.

40.2.2.4 SCE's General References to Electrification Policies Are Not Compelling.

SCE's direct testimony in support of its depreciation recommendations describes as an emerging issue the impact that California's "Net Zero by 2045" goal will have on the appropriate service lives for utility plant. SCE's witness described how the focus to date has been on how the natural gas industry and power generation will be impacted, but stated the expectation that there will be impacts on the electric industry as well. While he cited only impacts that would result service lives being shorter in the future than they have been in the past, "all else equal," SCE made no specific recommendations to shorten any service life due to these factors.[1640]

The Commission should recognize this element of SCE's depreciation showing as a marginally revised version of the analysis the same witness sponsored in PG&E's Test Year 2023 GRC when that utility sought to adopt a "Units of Production" method of depreciation to replace the straight-line method for gas distribution plant accounts. In D.23-11-069, the Commission determined the approach focused on gas assets was not "a solution ready for adoption in this GRC," and noted a series of "fundamental questions to consider before deciding upon its implementation."[1641]

The Commission should reach a similar conclusion here, and reject SCE's suggestion that the potential impacts of achieving the Net Zero by 2045 goal warrants adopting lower average service lives for electric plant at this time. This is particularly appropriate where the utility has again sought to re-purpose the rebuttal testimony its witness sponsored in the PG&E GRC as rebuttal testimony here. For example, SCE criticizes TURN's testimony because the "proposals

[1640] Ex. SCE-07, Vol. 3, pp 73-74.

[1641] D.23-11-069, pp. 658-661.

are instead primarily, if not entirely, based on the experience of the Company's assets in the past and do not give sufficient consideration of how the electric and gas industries of the future will be different from the past."[1642] This is word-for-word the same critique the same witness raised in rebuttal testimony submitted on behalf of PG&E.[1643] In light of the similarity of the underlying issues and the utility arguments regarding those issues, the Commission should not hesitate to reach an outcome identical to that adopted in the recent PG&E GRC, and adopt TURN's proposed service lives.

40.3 Small Hydro Decommissioning

SCE proposes small hydro decommissioning accruals based on a probability-weighted calculation that assigns each facility a likelihood of being decommissioned, a future year in which the decommissioning would commence, and an estimated decommissioning cost.[1644] SCE then escalates the probability-adjusted decommissioning cost estimate to the year's dollars in which the decommissioning is assumed to begin and determines annual accruals beginning in 2025.[1645] Under this approach, SCE would accrue $52.8 million in 2025 and beyond.[1646]

TURN recommends that the Commission deny decommissioning accruals for any facility that has less than a 90% of being decommissioned, an approach that would limit accruals to three specific facilities that have a 90-100% chance of commencing decommissioning during the GRC

[1642] Ex. SCE-18, Vol. 3, p. 16.

[1643] Ex. TURN-105 (Excerpt from PG&E Rebuttal Testimony from test year 2023 GRC), p. 12-13. And while SCE has edited the portion of rebuttal that appears under the heading "Forces Impacting the Service Lives of the Companies [*sic*] Assets," the argument is very similar to that included in PG&E's rebuttal under the heading "Factors Influencing PG&E's Future Service Lives." *Compare*, Ex. SCE-18, Vol. 3, pp. 18-23, with Ex. TURN-105, pp. 12-67 to 12-69.

[1644] Ex. SCE-07v3, pp.86-88.
[1645] Ex. TURN-13-E, p.111.
[1646] Ex. SCE-07v3, p.86.

cycle (San Gorgonio, Borel, Rush Creek/Agnew + Rush Meadows). This approach would result in annual accruals of $30.8 million, or a $22 million reduction relative to SCE's proposal.[1647]

In the 2021 GRC, SCE made an identical proposal that was rejected by the Commission. After reviewing the arguments offered by SCE in favor of beginning accruals for facilities assigned 50% and 10% probabilities of decommissioning, the Decision found that, "given the degree of uncertainty regarding when SCE may initiate decommissioning of these plants, the Commission finds that SCE does not present sufficient justification to begin recovery of decommissioning costs for these plants at this time."[1648] The final Decision limits decommissioning accruals to facilities with at least a 90 percent probability of being decommissioned, the same position TURN takes in this GRC.

In this GRC, SCE repeats the same arguments rejected by the Commission in the last GRC. For example, SCE explains that, for the three facilities assigned a 50% probability, the economic analysis of whether to continue operation "does not point strongly in either direction."[1649] For facilities assigned a 10% probability, SCE "generally anticipates that relicensing will be economically preferable to decommissioning."[1650] These characterizations are, almost word for word, identical to the rationales provided in the last GRC and rejected in D.21-08-036.[1651] The only new argument provided in this GRC is the unremarkable claim that all

[1647] Ex. TURN-13-E, p.113, Table 35. TURN's calculation includes the impact of several recommendations: (1) delaying assumed decommissioning for Borel, (2) using $2028 instead of nominal dollars, and (3) excluding projects that have less than a 90% probability of occurrence.
[1648] D.21-08-036, p.525.
[1649] Ex. SCE-05v1, p.142.
[1650] Ex. SCE-05v1, p.143.
[1651] D.21-08-036, p.525 ("With regard to the plants assigned a 50 percent probability, SCE explains that the financial and economic analyses of the costs to decommission versus the costs to continue operations do not point strongly in either direction. With regard to the plants assigned a 10 percent probability, 'SCE generally anticipates that relicensing will be economically preferable to decommissioning.")

small hydro assets "will at some point reach the end of their respective useful lives and require retirement."[1652]

The Commission should take note of the fact that several of the facilities included in SCE's probability matrix for decommissioning are currently undergoing federal license renewal. For example, Kaweah 3 has been assigned a 50% probability of beginning decommissioning in 2026 and Kaweah 1-2 has been assigned a 10% probability of beginning decommissioning in 2026.[1653] These probabilities are puzzling given SCE's insistence on seeking O&M costs driven by the relicensing of Kaweah expected to be completed in 2025.[1654] It is not reasonable for the Commission to approve O&M costs based on the assumption that the plant will be relicensed in 2025 and decommissioning accruals based on the assumption that the plant will be permanently retired in 2026. Similarly, SCE assigns a 10% probability of retirement to Bishop Creek in 2024 despite the fact that the plant is still operating in 2024 and is expected to receive a renewed federal license in 2026.[1655]

In rebuttal testimony, SCE expresses concern that failure to begin accruals for low probability plants in this GRC could require larger accruals in the 2029 GRC cycle (and cause "rate shock") if the economics of operating these plants becomes unfavorable.[1656] This claim is misleading and overblown. Using SCE's own accrual estimates, only $19.2 million (or 31%) out of $62.1 million in annual collections sought in this GRC involve projects with a decommissioning probability of 50% or lower.[1657] Moreover, one facility (Rush Creek Gem)

[1652] Ex. SCE-05v1, p.143.
[1653] Ex. SCE-05v1, p.141, Table II-26.
[1654] Ex. TURN-13-E, p.28; Ex. TURN-13-Atch1, SCE response to TURN Data Request 52, Q2a; Ex. SCE-16, p.25
[1655] Ex. SCE-05v1, p.141, Table II-26; Ex. TURN-13-E, p.28.
[1656] Ex. SCE-16, p.46.
[1657] Ex. TURN-13-E, p.110, Table V-30.

assigned a 50% probability of decommissioning in 2030 accounts for $8.4 million of the $19.2 million associated with lower probability facilities.[1658] SCE also expects that facility to receive a new federal license in 2029 that would enable many years of future operation.[1659]

Missing from SCE's analysis is any consideration of the impacts on current ratepayers who are facing a crisis of affordability due to high electricity rates. Given the highly speculative nature of future decommissioning dates and probabilities, the Commission should favor proposals that minimize the burdens placed on current ratepayers. Adopting TURN's proposal to limit accruals to projects with at least a 90% probability of decommissioning, which mirrors the outcome adopted in D.21-08-036, strikes the correct balance.

40.4 Generation Decommissioning Escalation

SCE's proposal for accruing decommissioning costs for all generation units uses nominal dollars rather than constant dollars for the remaining years of plant life prior to decommissioning.[1660] This proposal was rejected by the Commission in the prior two GRCs in favor of an approach that calculates future decommissioning expense in constant dollars tied to the final year of the GRC cycle.[1661] TURN's proposal in the current GRC mirrors the approach adopted by the Commission in these prior two cases by calculating accruals in this cycle based on constant $2028.[1662]

Although this issue has been litigated in two successive GRCs, SCE presses the Commission to reconsider its precedents by offering the same arguments that were used in the

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[1658] Ex. TURN-13-E, p.110, Table V-30.
[1659] Ex. TURN-13-E, p.28.
[1660] Ex. SCE-18v3, pp.55-58.
[1661] D.19-05-020, pp.324-325; D.21-08-036, pp.525-528.
[1662] Ex. TURN-13-E, pp.111, 115.

prior cases. The primary argument relied upon by SCE is the claim that TURN's proposal "results in much lower accruals early in the asset's life that are made up for with much higher accruals at the end of the asset's life."[1663] Additionally, SCE argues that TURN's approach would result in accrual escalation growing "at many times the rate of inflation" in the final years prior to asset retirement.[1664] The Commission previously addressed these arguments.

In D.21-08-036, the Commission explained that the use of inflation-adjusted accruals "appropriately accounts for the time value of money and avoids the result of current ratepayers paying on a vastly overinflated expense."[1665] By SCE's own admission, its preferred approach would result in front-loaded customer contributions that decline (in real dollars) throughout the collection period.[1666] TURN's alternative is designed to adjust the burden on customers over time and reduce the real dollar total obligations to ratepayers over the entire period. In D.21-08-036, the Commission explained that, due to differences in real dollar impacts, "SCE incorrectly assumes that the total amount to be collected over a 20-year period under TURN's method would be the same as under the straight-line method."[1667] SCE's comparison of proposals in this case ignores the fact that different methods of collecting the same amount of nominal dollars over an extended period do not result in the same real dollar impacts on customers.[1668] Conversely,

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[1663] Ex. SCE-18v3, p.58.
[1664] Ex. SCE-18v3, p.57.
[1665] D.21-08-036, page 526.
[1666] Ex. TURN-712, SCE response to TURN Data Request 117, Q62(e).
[1667] D.21-08-036, p.527.
[1668] Ex. SCE-18v3, p.57. Table V-10 claims to show that the same amount of nominal dollars would be collected under the SCE and TURN proposals but does not adjust the annual contributions to constant dollars to reflect the time value of money. This failure renders the comparison flawed. Applying a 7% discount rate to the annual values on that table, which approximates the utility cost of capital, results in a 7.8% reduction in real dollar obligations between 2022-2040 under the TURN approach. The use of a discount rate that exceeds inflation appropriately reflects the increased value that residential customers place on current year dollars.

SCE's approach would allow SCE to overcollect (in real dollars) and retain the time value benefits for its shareholders.

SCE's rebuttal testimony points out that TURN's proposal to use 2028 dollars for calculation of the accrual would result in an accrual for SCE's hydro that is $2 million higher than proposed by SCE.[1669] This result is not surprising since SCE's proposed revenue requirement assumed that the San Gorgonio project would be fully decommissioned by the end of 2025[1670] and that Bishop Creek 2-6 would start decommissioning in 2024 and complete it in 2027. Both assumptions are flawed and result in an understatement of the decommissioning accrual for small hydro using SCE's nominal dollar approach.

SCE admits that decommissioning efforts for San Gorgonio have not yet commenced.[1671] During cross examination, SCE witness Allen noted that major storms in 2023 and early 2024 left some areas inaccessible and, as of May 2024, prevented the development of damage assessments that could inform expectations of what projects could be completed in the coming years.[1672] It is therefore unreasonable to assume that SCE could complete the decommissioning of San Gorgonio on the schedule assumed by SCE when it calculated its decommissioning accrual for that plant. Delay would result in increased nominal dollar costs for the decommissioning of San Gorgonio, which would increase SCE's assumed accrual for hydro.

SCE's assumption that Bishop Creek would be decommissioned by 2027 is also unreasonable since Bishop Creek is still operating in 2024 and is expected to receive a renewed federal license in 2026.[1673]

[1669] Ex. SCE-18v3, Table V-9, p.55.
[1670] Ex. SCE-07v3WP, p.111.
[1671] Ex. SCE-16, p.40.
[1672] Transcript, May 15, pp.1039-1040.
[1673] Ex. SCE-05v1, p.141, Table II-26; Ex. TURN-13-E, p.28.

When more reasonable assumptions are used for the decommissioning dates for these two plants, the difference between TURN and SCE's accrual for small hydro becomes *de minimus*.

TURN urges the Commission to affirm the treatment adopted in the prior two GRCs and require that decommissioning accruals be collected using constant dollars. This approach correctly balances the interests of current and future ratepayers and prevents overcollections (in real dollars) that benefit utility shareholders.

40.5 Solar PY

TURN addresses decommissioning cost issues relating to the SPVP projects in Section 24.4.2.3 since this topic was included in the main body of SCE's generation rebuttal testimony (Ex. SCE-16).

40.6 Fuel Cell Generation

TURN addresses cost recovery issues relating to the Fuel Cell projects in Section 24.3 since this topic was primarily included in the main body of SCE's generation rebuttal testimony (Ex. SCE-16).

40.7 Miscellaneous/Other

41. POST TEST YEAR RATEMAKING

SCE and TURN both propose a two-part post-test year ratemaking (or "attrition") mechanism with separate annual revenue requirement adjustments for expense and capital during the 2026-2028 post-test years. The disputes between TURN and SCE boil down to four issues: (1) the index to use for escalating authorized test year O&M expense; (2) whether to use a trended historical average of capital additions for capital attrition or to escalate test year capital additions for the "basic" capital attrition mechanism; (3) how to calculate test year capital additions for purposes of determining attrition year capital additions; and (4) whether to exclude any cost categories from the general capital attrition mechanism, beyond wildfire mitigation, and instead to authorize post-test year budgets for those activities.

SCE proposes to escalate O&M expense using S&P Global Market Intelligence's (formerly IHS Markit's and before that, Global Insight's) proprietary utility-specific indices. TURN would escalate all O&M expense based on general inflation using CPI-U. SCE seeks to escalate test year capital additions using S&P Global Market Intelligence indices to determine basic capital attrition, while TURN would use a trended 7-year average of recorded capital additions for 2016-2022, excluding recorded additions for wildfire mitigation. SCE would modify the calculation of test year capital additions (that would then be escalated in its basic capital attrition mechanism) by adding an adjustment for the lag in some capital expenditures closing to plant, while TURN opposes this adjustment. And SCE would add attrition year budgets for four specific capital projects and wildfire mitigation, while TURN proposes budget-based attrition only for wildfire mitigation capital (specifically, Targeted Undergrounding and Covered Conductor).[1674]

For the reasons explained below, the Commission should find that TURN's two-part attrition mechanism meets the objectives of attrition and more reasonably balances the interests of ratepayers and shareholders during the post-test year period than SCE's proposal.

[1674] *See, e.g.,* Ex. SCE-07V04, pp. 26 (overall mechanism), 34 (adjusted calculation of test year capital additions); Ex. TURN-17 (Yap), pp. 1-2.

41.1 Attrition Is Intended to Provide Some Reasonable Relief to Shareholders Between General Rate Cases, Not Guarantee Company Earnings.

Attrition is a mechanism that the Commission has used to offset the financial risk experienced by the utilities between general rate cases.[1675] The Commission adopted the original attrition mechanism in 1980 during a period of very high inflation.[1676] By 1996, the Commission still characterized attrition mechanisms as an exception to the general strategy of examining one test year out of every three years and providing the utility an incentive to improve its productivity; the Commission only allowed attrition adjustments in years when inflation was high.[1677] Since that time, the Commission has continued to affirm its discretion to grant or deny attrition requests, and has maintained that the utilities are not automatically entitled to an attrition mechanism between rate cases.[1678]

Moreover, the Commission has made it quite clear over the years that attrition does not provide a guarantee of earnings but rather a reasonable offset to increasing costs:

> Attrition is the year-to-year decline in a utility's earnings caused by increased costs that are not offset by increased rates or sales. In order to protect utility-shareholders from the effects of attrition to some extent, the Commission has-adopted a ratemaking mechanism called the Attrition Rate Adjustment (ARA). The ARA mechanism was designed to 'provide utilities with the reasonable opportunity of achieving their authorized rates of return during years in which they are not permitted under the Commission's rate case plan procedures to file for general rate relief but in which they still face volatile economic conditions.'[1679]

Similarly, attrition allowances "are not intended to insulate utilities from economic pressures that

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[1675] D.92497, Cal. PUC LEXIS 1024; 4 CPUC2d 725 (December 5, 1980) at *101.

[1676] *Id.*

[1677] D.00-02-046, p. 428 (discussing Re Pacific Gas and Electric Company (1996) 69 CPUC2d 691, 695).

[1678] *See, e.g.,* D.21-08-036, p. 546.

[1679] D.04-05-055, p. 26 (citing D.85-12-076, Finding of Fact 1, 9 CPUC 2d 453,476).

all businesses experience."[1680] Unlike a test year cost of service analysis, an attrition mechanism serves "merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity."[1681]

In a number of cases the Commission has specifically found that a utility's attrition proposal placed too great a burden on ratepayers and significantly reduced the authorized attrition amount.[1682] While TURN is not proposing that the Commission deny attrition relief to SCE in the pending case, nonetheless the utility's need for increased funds to offset rising costs should be balanced against the burden that higher rates place on ratepayers.

41.1.1 SCE Confuses Attrition with Cost of Service Ratemaking.

SCE claims its proposed attrition mechanism is "based on the principles of cost-of-service ratemaking" and asserts that adopting anything other than SCE's "cost-of-service PTYR mechanism" would be "inconsistent with SCE providing safe and reliable operations while maintaining financial integrity."[1683] Yet the Commission has stated previously that the attrition rate adjustment "is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee…rate of return."[1684]

[1680] D.04-07-022, p. 270.

[1681] D.14-08-032, pp. 652-653. *See also* D.20-01-002, p. 41 (affirming this language and accordingly rejecting SCE's request for assurance that under the new four-year rate case plan adopted in that decision, utilities would receive an attrition mechanism that "fully compensates the utility for its costs of service in the attrition years").

[1682] *See, e.g.,* D.09-03-025, pp. 305-306 and D.13-05-010, pp. 1009-1010.

[1683] Ex. SCE-18V04, pp. 2-3.

[1684] D.14-08-032, p. 652.

SCE asserts that it would be "unreasonable for the Commission to adopt a post-test year mechanism that does not allow the utility to continue operations" at the standard established by the Commission.[1685] SCE then presents a table illustrating the extent to which TURN's (and Cal Advocates') attrition proposals fall short of SCE's requests in terms of attrition year revenue requirements, O&M escalation, and capital additions.[1686] SCE warns of the consequences to SCE and its customers if SCE's attrition proposals are not adopted.[1687]

It is important to recognize that SCE's table compares TURN's proposals to SCE's *requested* attrition adjustments, not SCE's post-test year *spending needs*. SCE's overall post-test year spending needs have not been vetted in this proceeding. On the other hand, SCE's test year needs have been vetted, and intervenors have recommended adjustments to many of the utility's O&M and capital proposals. TURN cannot recall a litigated GRC decision in which the Commission authorized the utility to proceed with 100% of its proposed O&M and capital investments over the rate case period. The Commission should not presume that the utility's post-test year O&M and capital investment plans are reasonable for the purpose of evaluating attrition mechanism proposals.

Moreover, while the Commission may establish performance standards and determine reasonable GRC revenue requirements, the Commission leaves it to SCE to determine how best to operate within the established parameters, subject to spending accountability oversight. SCE routinely claims it cannot operate safely and reliably without its proposed test year (or attrition year) revenue requirement, which reflects SCE's belief in its own claims about the need for

[1685] Ex. SCE-18V04, p. 3.

[1686] Ex. SCE-18V04, p. 4.

[1687] Ex. SCE-18V04, p. 5, Table I-1.

greater and greater amounts of revenue requirement. However, the Commission has previously granted SCE less revenue requirement than it had requested[1688] and has even reduced SCE's test year revenue requirement,[1689] despite SCE's claims that it could not operate safely and reliably at lower revenue requirements. SCE has nonetheless been able to operate successfully. GRC cost of service ratemaking does not prescribe a particular revenue requirement level in a specific post-test year period, but rather dictates a level of increase that balances concerns about the utility's financial health against other important factors, such as the need to encourage the utility to stretch into greater productivity and the need to consider whether ratepayers can absorb the corresponding rate increases.[1690]

Finally, SCE points specifically to TURN's proposed attrition year budgets for wildfire mitigation capital, warning that TURN's proposal "is barely one-half of the amounts that SCE has proposed."[1691] SCE states that TURN's attrition recommendations "would cause SCE to contemplate reductions in service to customers and significant reductions in system improvements and wildfire mitigation activities."[1692] This argument is a red herring. TURN supports SCE's proposal to establish attrition year capital budgets for wildfire mitigation, as discussed below. To the extent the Commission finds TURN's proposed budgets more reasonable than SCE's, the "shortfall" would not be the fault of TURN's proposed attrition

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[1688] *See, e.g.,* D.09-03-025, pp. 5, 6.

[1689] In SCE's 2018 GRC, the Commission adopted a test year revenue requirement that was 7.53% ($417 million) lower than SCE's request, where SCE had already requested a $22 million revenue requirement *decrease*, and attrition increases that were approximately $100 million lower than requested by SCE for each attrition year. D.19-05-020, pp. 2-3.

[1690] *See e.g.,* D.14-08-032, p. 652 ("[W]e seek to promote [the utility's] incentive to stretch to achieve productivity between test years.").

[1691] Ex. SCE-18V04, p. 3.

[1692] Ex. SCE-18V04, p. 4.

mechanism. Rather, the shortfall would reflect the Commission's determination of the appropriate level of spending on wildfire mitigation in this GRC cycle.

41.2 O&M Attrition Should Be Based on General Inflation (CPI-U).

As noted above, SCE proposes to escalate authorized Test Year O&M expense in each year of the post-test year period on a highly tailored basis using S&P Global Market Intelligence's proprietary utility-specific indices.[1693] This is the same approach to forecasting escalation that SCE proposes for establishing test year expense levels.[1694]

While SCE's utility-specific indices may be appropriate for projecting test-year expenses, which the Commission now establishes every four years, the complex and utility-specific indices are not the best choice for the attrition period. These complex indices simply pass along the costs of business-as-usual activities during the attrition period, providing little incentive for SCE to keep its costs down. Indeed, SCE acknowledges that its proposals are "based on the actual impact of inflation on the costs of providing utility service in the attrition years."[1695]

However, as the Commission most recently recounted in D.20-01-002, an attrition mechanism

> is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [the utility's] rate of return [during the attrition years]," but "is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity."[1696]

[1693] Ex. SCE-07V04, p. 26.

[1694] *Id.*

[1695] Ex. SCE-18V04, p. 1.

[1696] D.20-01-002, p. 41 (quoting TURN's comments which quoted and cited D.14-08-032, pp. 652-653).

Similarly in SCE's 2015 GRC decision, the Commission authorized an attrition mechanism to, in pertinent part, "give SCE an opportunity to offset *some* inflationary price increases," not to make SCE indifferent to inflation.[1697] The Commission similarly explained in D.14-08-032, "[W]e seek to promote [the utility's] incentive to stretch to achieve productivity between test years."[1698] Thus, SCE's proposal to incorporate each of the complex and proprietary indices used to establish test year expense levels is not the best choice to increase expense levels for the attrition period.

For the reasons provided below, the Commission should reject the utility's request and instead incorporate broad indices for all O&M escalation in the attrition years to provide the proper incentives to utility management to manage costs.

41.2.1 Using a Broad Index for O&M Escalation Reasonably Addresses Inflation-Related Cost Pressures While Providing the Utility an Incentive to Manage its Operations as Efficiently as Possible.

In D.04-05-055, the Commission summarized the attributes of the historical attrition mechanism:

> The traditional attrition mechanism provides for an advice letter filing, just prior to the attrition year, by the utility seeking increased rates based on the escalation of adopted TY GRC expense and rate base. A seven-year average of plant additions is used to account for rate base growth during the attrition period. The escalation rates are conventional indices such as the U.S. Department of Labor, Bureau of Labor Statistics' CPI, and DRI.[1699]

[1697] D.15-11-021, p. 389.

[1698] D.14-08-032, p 652.

[1699] D.04-05-055, p. 27.

In this GRC, TURN recommends that the Commission apply the traditional attrition mechanism and base O&M escalation on a broad inflation index.[1700] TURN specifically proposes to escalate SCE's authorized test year 2025 O&M expenses by CPI-U to determine the appropriate amount for O&M expenses in attrition year (AY) 2026. SCE's AY 2026 O&M expense levels would similarly be escalated by CPI-U to determine AY 2027 O&M levels, with the same approach used to escalate AY 2027 O&M levels for AY 2028.

The choice of how to estimate inflationary effects for purposes of utility ratemaking is a policy matter. TURN's position is that use of S&P Global Market Intelligence's indices is generally not objectionable for setting test year cost of service revenue requirements (exceptions may apply). On the other hand, attrition year adjustments are not updates to cost of service; such updates occur with the next GRC. The Commission must consider whether SCE's proposed attrition mechanism, with its myriad of account specific escalators, best serves the Commission's purpose of promoting SCE to "stretch to achieve productivity" in attrition years 2026-2028. TURN submits that the PTY escalation index that SCE requests using, S&P Global Market Intelligence's various utility cost forecasts, is simply too protective of SCE to properly incent it to manage operations productively before its next GRC. Use of a broad index like CPI as a measure of inflation during the PTYs, rather than an index that more precisely tracks the escalation in utility costs (like S&P Global Market Intelligence), is a reasonable method of achieving the Commission's purpose in providing attrition adjustments.

TURN understands that the Commission has, on a number of recent occasions, relied on forecasts of escalation that are specific to utility sector costs for purposes of attrition instead of

[1700] Ex. TURN-17 (Yap), p. 14.

the CPI-U, while expressing its concern that CPI-U "does not specifically cover the prices of the typical goods [the utility] purchases."[1701] The Commission reached this conclusion in many recent SCE GRCs.[1702] However, such an approach is not required to fulfill the purpose of attrition. As noted above, an attrition mechanism "is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [the utility's] rate of return [during the attrition years]," but "is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity."[1703]

The Commission should not shy away from recognizing the utility's own responsibility to manage costs and improve efficiencies during the rate case cycle. Adopting an attrition approach that mimics test year cost of service ratemaking undermines the utility's incentive to do so. The Commission made this clear in its decision in the Sempra Utilities' Test Year 2012 GRC, D.13-05-010:

> Having reviewed all of the testimony and arguments of the parties concerning the PTY proposals, we hesitate to adopt the proposal of SDG&E and SoCalGas to adopt their PTY ratemaking mechanisms. Their proposed mechanisms seek to include the use of two formulas which lean in their favor. These are the use of Global Insight's utility-specific cost index, and a California-specific health care cost index. Although these utility-specific indexes may be a better reflection of the PTY costs in a "business as usual" setting, such indexes, if adopted, will not provide the Applicants with an incentive to manage and reduce their costs during the PTY period.[1704]

[1701] *See, e.g.,* D.04-07-022, p. 278.

[1702] D.21-08-036, p. 547.

[1703] D.14-08-032, pp. 652-653. *See also* D.20-01-002, p. 41 (affirming this language and accordingly rejecting SCE's request for assurance that under the new four-year rate case plan adopted in that decision, utilities would receive an attrition mechanism that "fully compensates the utility for its costs of service in the attrition years").

1704 D.13-05-010, p. 1008.

The Commission further clarified that use of Global Insight's utility specific cost index in setting the test year revenue requirement "does not mean we should automatically use those same indexes for the PTY period."[1705] The Commission accordingly chose to replace the utility specific indices proposed by SoCalGas and SDG&E with an index based on CPI-U plus 75 basis points.[1706]

Here, too, the Commission should weigh the importance of proper incentives for the utility during the PTY period more highly than the need to compensate the company exactly for any change in its expenses between test years.

Moreover, it is appropriate for the Commission to adopt an attrition mechanism that protects ratepayers from the "cumulative adverse burdens on customers of absorbing such large attrition increases on top of significant test year increases," as the Commission recognized in D.14-08-032 (quoted above).[1707] In SCE's 2018 GRC decision, the Commission concluded that "limiting the annual increase in SCE's revenue requirements during this GRC period to" the rate of growth in customer income is necessary to "begin to strive for greater affordability."[1708] Given that CPI-U is the index used by the Social Security Administration to adjust retirement benefits and Supplemental Security Income payment amounts each year, its use in escalating O&M expense in the post test years supports the Commission's intention to strive for greater affordability.[1709]

1705 D.13-05-010, p. 1009.

[1706] D.13-05-010, p. 1010.

[1707] D.14-08-032, p. 657.

[1708] D.19-05-020, p. 20.

[1709] Ex. TURN-17 (Yap), p. 15.

For all of these reasons, the Commission should conclude that the use of CPI-U to escalate O&M expense in the attrition years best balances the interests of shareholders and ratepayers in this GRC period.

41.3 Capital Attrition Should Be Based on Seven Years of Recorded Capital Additions With an Exception for Wildfire Mitigation.

TURN recommends that the Commission apply the time-tested "traditional" approach to capital attrition in this GRC for non-wildfire mitigation capital, despite that the Commission has not adopted this approach for SCE in the past 20 years.[1710] That traditional approach involves trending a seven-year average of recorded plant additions.[1711] TURN excluded recorded additions for wildfire mitigation in calculating the seven-year average, as TURN recommends budget-based attrition for wildfire mitigation.[1712]

The Commission has adopted a modified version of this traditional capital attrition mechanism for PG&E, SDG&E, and SoCalGas in recent years. In the PG&E 2014 GRC, the Commission adopted a seven-year average combining recorded data with forecasted data (2008-2014). The Commission highlighted the value of incorporating an historical average:

> Use of an historical average is consistent with the approach applied in the past, and normalizes actual utility spending variations over time. Without conducting full-scale review of 2015 and 2016 capital spending requirements, reliance on historical averages offers a reasonable outcome.
>
> We find insufficient basis to rely on PG&E's assumption that 100% of test year additions should also constitute the basis for trending each of the attrition years.[1713]

[1710] Ex. TURN-17 (Yap), p. 11, Table 1.

[1711] D.04-05-055, p. 27.

[1712] Ex. TURN-17 (Yap), pp. 15-16.

[1713] D.14-08-032, p. 657.

Similarly, in the SDG&E/SoCalGas 2019 GRC, the Commission adopted a seven-year average combining five years of recorded data with two years of forecasted capital additions (2013-2019). The Commission asserted that incorporating historical capital additions provides an important counterbalance to the utility forecast of capital additions.[1714] The Commission extended that same mechanism for another two years in D.21-05-003 after conducting a detailed review.[1715] Furthermore, SDG&E and SoCalGas have proposed trended capital additions as the basis for capital attrition in their currently pending 2024 GRC, A.22-05-015 et al.[1716]

While the Commission has most recently adopted trended capital additions combining recorded and forecast data, TURN urges the Commission to reconsider the use of forecasted capital additions in this GRC. Using the higher forecasted test year capital in the averaging formula instead of the lower recorded capital may bias the projected attrition-year capital values upward if the after-the-fact recorded figures do not match the forecast.[1717] This bias could cut either way, as the authorized test year forecast will still be a forecast. For example, SCE's actual 2023 capital expenditures were $262 million lower than its 2023 capital forecast in this GRC.[1718] Using recorded values for all seven years avoids introducing this uncertainty and the associated risk to ratepayers.

[1714] Ex. TURN-17 (Yap), p. 13; D.19-09-051, p. 709.

[1715] D.21-05-003, Ordering Paragraph 2.

[1716] Ex. TURN-17 (Yap), p. 13.

[1717] See Ex. TURN-17 (Yap), p. 17, Figure 1.

[1718] Ex. SCE-18V01, p. 114.

41.3.1 SCE's Critiques of TURN's Capital Attrition Mechanism for Non-Wildfire Should Be Dismissed.

First, SCE asserts that TURN "mispresents historical Commission decisions that address the capital portion of the major energy utility attrition mechanisms."[1719] SCE compares TURN's statement that "the great majority of PTY decisions that adopted a two-part mechanism have determined the capital portion based on trending of recorded capital additions" with the decisions shown in Table 1 in TURN's testimony.[1720] SCE misunderstands TURN's statement.

When one reads the entire sentence from which SCE's excerpt is taken, it becomes clear that TURN was discussing the full history of attrition decisions since 1980 in referring to the "great majority" of decisions, not simply the decisions since 2004 included in Table 1.[1721] TURN agrees that the Commission has adopted a capital attrition approach using trended recorded capital additions in 3 of the most recent 12 litigated GRC decisions, while escalating test year capital additions in 5 GRC decisions. Both are contemporary approaches to attrition, while using trended recorded capital additions is also the traditional approach generally applied by the Commission from 1980 until 2004.[1722]

Next, SCE criticizes TURN's non-wildfire capital attrition mechanism because it relies on 2016-2022 recorded additions and thus "bears no relationship to Test Year authorized capital expenditures."[1723] SCE argues that historical data is important in GRCs "as it guides the

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[1719] SCE-18V04, pp. 2, 11-12.

[1720] SCE-18V04, p. 11.

[1721] Ex. TURN-17 (Yap), p. 11 ("Furthermore, if we consider the full history of the PTY (attrition) mechanism as characterized in the excerpt from D.04-05-055 [which describes the "traditional" attrition mechanism], the great majority of PTY decisions that adopted a two-part mechanism have determined the capital portion based on trending of recorded capital additions.").

[1722] D.04-05-055, pp. 27, 30-32.

[1723] Ex. SCE-18V04, pp. 2, 12.

development of a Test Year forecast, but the authorized revenue requirements should be established based on reasonable expectations of SCE's future cost of service, not its past."[1724] However, the Commission has made clear that a capital attrition adjustment mechanism need not cover all attrition year capital expenditures – either projected by the utility or actual.

In PG&E's 2014 GRC, PG&E argued that capital attrition based on a 7-year average would be inadequate because PG&E's projected attrition year capital investment levels would be "much higher than a seven-year historic average."[1725] The Commission dismissed PG&E's concern, noting that PG&E's criticisms mistakenly presupposed that its attrition year spending forecasts were reasonable, when those spending plans had not received close scrutiny (unlike test year spending).[1726] The Commission further acknowledged that a 7-year average would "not necessarily cover all attrition year capital expenditures that PG&E may ultimately find prudent."[1727] Even so, the Commission noted, "the Commission historically has not closely covered projected revenue requirement through an attrition mechanism," yet rate base has grown.[1728] The Commission also explained that a 7-year average would provide PG&E "a stronger incentive to find ways to curb the rate of spending growth."[1729] The Commission ultimately concluded that "use of a seven year average better balances the interests of both ratepayers as well as shareholders than does PG&E's methodology."[1730]

[1724] Ex. SCE-18V04, p. 12.

[1725] D.14-08-032, p. 657. In that case, PG&E proposed to escalate authorized test year capital additions. (D.14-08-032, p. 656).

[1726] D.14-08-032, pp. 657-658.

[1727] D.14-08-032, pp. 658-659.

[1728] D.14-08-032, pp. 658-659.

[1729] D.14-08-032, p. 657.

[1730] D.14-08-032, p. 657.

41.3.2 Wildfire Capital Attrition Should Be Based on Attrition Year Budgets.

TURN supports SCE's proposal to use a budget-based forecast for wildfire mitigation capital additions during the attrition period. As TURN acknowledged in testimony, it would not be appropriate to simply trend recorded capital addition amounts for wildfire mitigation because the rate of change for wildfire mitigation capital additions is very different now than the rate of change in the previous GRC.[1731] TURN witness Yap explained:

> As shown previously, the magnitude of those wildfire mitigation capital expenditures are truly staggering. They are too large to be handled on a trended test year capital additions basis. Furthermore, the risk spend ratios for each wildfire mitigation activity need to be taken into account when determining the appropriate priority for the use of ratepayer dollars. Hence, careful consideration of the appropriate mix of wildfire mitigation capital programs as well as the proper level of wildfire mitigation capital expenditures is warranted for each year of the GRC cycle. TURN has provided such an evaluation of the appropriate capital expenditure levels for each year of the GRC cycle in TURN's testimony regarding wildfire capital expenditures [citing Ex. TURN-12 (Borden)].[1732]

SCE takes issue with TURN's proposed budgets for wildfire mitigation, claiming TURN's proposal "would result in insufficient funds to mitigate wildfire safety risks."[1733] TURN addresses the appropriate attrition year capital budgets for wildfire mitigation in Section 15 of this brief.

41.3.3 SCE's Other Budget Based Attrition Proposals Should Be Denied.

SCE proposes that four additional specific projects be added on a budget basis to the trended capital additions and wildfire budgeted capital additions because these specific projects

[1731] Ex. TURN-17 (Yap), p. 7.

[1732] Ex. TURN-17 (Yap), p. 7.

[1733] Ex. SCE-18V04, p. 10.

have "uneven capital additions" over the PTY period.[1734] SCE points to the Commission's special treatment of SoCalGas' Pipeline Safety Enhancement Plan (PSEP) projects in D.19-09-051 as justification for this budget based treatment.[1735] The Commission should reject SCE's proposal for this budget based treatment of these specific projects for several reasons.

First, the bulk of the projects ($660 million) are scheduled as capital additions in 2028, which is the last year of the GRC cycle, although a few of them ($225 million) are scheduled for 2027.[1736] SCE is making a long term capital forecast based on information available in 2022 and early 2023 for activities that will occur four to five years later. Yet there is a very real possibility for delays in construction schedules due to problems with permitting or construction activities (unforeseen events, weather, etc.).[1737] In fact, TURN has opposed funding for one of these projects, the T&D Training Center (aka Edison Training Academy), because of persistent delays during the 2018 and 2021 GRC cycles, despite authorized funding in both cases for this project.[1738] These projects could miss the entire PTY period due to delays, but under SCE's proposal, ratepayers would have to pay anyway for the phantom capital additions.

Second, SCE attempts to draw a parallel between these non-wildfire related projects and the PSEP projects that the Commission considered in D.19-09-051, claiming that the Commission was focused somehow on uneven or insufficient capital investment. However, that comparison is completely faulty. If any comparison should be made to the PSEP projects, it

[1734] Ex. SCE-07V04, p. 37.

[1735] Ex. SCE-07V04, p. 37.

[1736] Ex. SCE-07V04, p. 37, Table III-18.

[1737] Ex. TURN-17 (Yap), p. 8.

[1738] Ex. TURN-11 (Defever), pp. 6-8. TURN addresses funding for the T&D Training Center / Edison Training Academy in Section 36 of this brief.

should be made with SCE's wildfire mitigation projects. Each of the proposed PSEP projects were subject to detailed project review.[1739] The flexibility that the Commission adopted for "PSEP capital-related costs not fully reflected in the TY2019 revenue requirement" by permitting them to "be included as part of the PTYs" was directed at a safety program for which the utility was for the first time receiving base rate treatment.[1740] Similarly, D.19-09-051 provided a memorandum account for PSEP, which was directed at ensuring that the safety programs were completed in a timely fashion and subject to reasonableness review.[1741]

This is not the same situation that SCE is facing with its proposals to enhance buildings or augment substations. SCE is simply looking for an opportunity to beef up its attrition earnings in the later years of the GRC cycle. The Commission has historically frowned upon budget-based attrition. It rejected SCE's request for budget-based capital attrition in every GRC from the 2006 GRC through the 2018 GRC and permitted only narrow exceptions in the 2021 GRC.[1742] The Commission has adopted budget-based attrition in limited circumstances where the costs at issue are truly extraordinary.[1743] The Commission should deny SCE's inappropriate request to augment its capital attrition mechanism with budgeted amounts for non-wildfire mitigation projects.

[1739] D.19-09-051, pp. 198-207, 209-216.

[1740] D.19-09-051, pp. 215-216.

[1741] D.19-09-051, pp. 218-219.

[1742] D.19-05-020, pp. 283-285; D.21-08-036, pp. 548-549.

[1743] D.21-08-036, pp. 547-550.

41.4 If the Commission Adopts SCE's Basic Capital Attrition Mechanism, the Commission Should Apply the National Version of Capital Escalation Indices and Reject SCE's Test Year Capital Additions "Lag" Adjustment.

TURN understands that the Commission may conclude that test year capital additions should be escalated to determine attrition year capital revenue requirements, as SCE proposes. In that case, TURN recommends that the Commission reject two elements of SCE proposal.

41.4.1 Test Year Capital Additions Should Be Escalated Using Nationally-Based Rather Than Regionally-Based Capital Indices.

SCE proposes to tie its capital additions levels in the PTY period to an escalation of test year capital additions (except for wildfire and some other selected projects, as noted above). SCE proposes to escalate capital additions with an SCE-specific weighting of regional construction cost indices provided by S&P Global Market Intelligence, rather than the national version of capital indices.[1744] This is in contrast to the nationally based indices that SCE proposes to use for O&M escalation.[1745]

If the Commission is inclined to adopt a capital index based on SCE specific weighting combined with S&P Global Market Intelligence indices, TURN strongly recommends that the Commission incorporate the national rather than regional basis for the capital indices that are applied to the weighting.[1746] Using regional indices makes the escalation too tailored to SCE's behavior. SCE is a large enough utility to influence the level of the regional indices.[1747]

Comparing the utility to itself or to similarly situated businesses reduces the pressure on the utility to stretch. In fact, if the indices are fashioned too narrowly, the attrition simply

[1744] Ex. SCE-07V01, p. 114.

[1745] Ex. TURN-17 (Yap), p. 4.

[1746] Ex. SCE-07V01, p. 110.

[1747] Ex. TURN-17 (Yap), p. 4.

becomes a self-fulfilling prophecy where the more the utility expends, the more will be passed along in the future. As the Commission previously explained, "although these utility-specific indexes may be a better reflection of the PTY costs in a 'business as usual' setting, such indexes, if adopted, will not provide the Applicants with an incentive to manage and reduce their costs during the PTY period."[1748]

The Commission has previously addressed this issue in depth. In designing performance based regulation ("PBR") mechanisms in the 1990s, the Commission reflected on the fact that the use of narrow escalators might reduce the incentive for utility efficiency:

> To make this update of utility rates independent of the utility's costs, the price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its own cost and productivity. In contrast, traditional regulation often updates rates through a review of the utility's own costs and productivity.[1749]

TURN submits that incentivizing efficient utility behavior during the PTY period is critical. As discussed in TURN's affordability testimony (Ex. TURN-02), SCE's customers are already struggling to keep up with rapidly increasing electricity bills, and SCE's GRC request will likely further exacerbate those affordability challenges. Thus, if the Commission is inclined to adopt a capital index based on SCE-specific weighting combined with S&P Global Market Intelligence indices, TURN strongly recommends that the Commission incorporate the national version of these indices rather than the regional version when applying them to the SCE-based weighting factors.[1750]

[1748] D.13-05-010 (SDG&E/SoCalGas 2012 GRC), p. 1008.

[1749] D.97-07-054, 1997 Cal. PUC LEXIS 751; 179 P.U.R.4th 237 (July 16, 1997) at *30.

[1750] Ex. SCE-07V01, p. 110.

41.4.2 SCE's Proposed Adjustment to Mitigate the "Lag" in Capital Expenditures Closing to Plant is Inappropriate.

On top of its request to escalate capital additions from the test year to be adopted as capital additions in during the PTY period, SCE asks to have its capital additions for the test year calculated in a more complex fashion where the lag in some capital expenditures closing to plant is reflected in the capital additions amount. SCE proposes to continue this lagging calculation into the PTY period. The Commission should reject SCE's proposal to calculate capital additions during the PTY period on a more complex basis.

An examination of the history of capital expenditures closing to capital additions demonstrates that SCE's projected 55 percent figure for plant closings in the test year may be somewhat low.[1751] In any case, SCE's RO model already reflects the lag in capital expenditures when it calculates capital additions for the test year; the test year 2025 capital additions calculated by the model already include construction work in progress carried over from 2024 and earlier years. As TURN witness Yap explained:

> Capital additions, which are generally referred to in Commission decisions, are derived from projected construction work in progress ("CWIP") at the end of the previous year, combined with proposed capital expenditures plus cost of retirement, overheads, and allowance for funds used during construction ("AFUDC"). Weighted average capital additions net of retirements are then added to the previous year's end of year plant in service to determine the current year's weighted average plant in service, which is the largest component of rate base.[1752]

SCE has used this same approach to develop the test year capital additions for decades.[1753] There is no reason to further adjust post-test year capital additions to account for a lag in capital

[1751] Ex. TURN-17 (Yap), p. 5.

[1752] Ex. TURN-17 (Yap), pp. 3-4 (citing SCE RO Model).

[1753] Ex. TURN-17 (Yap), pp. 6.

expenditures closing to capital additions or to add this “lag” adjustment to escalated test year additions to determine attrition year capital costs.

While SCE points to the “lag” in capital expenditures closing to capital additions to justify its proposed methodology, the real culprit appears to be SCE’s proposal to dramatically increase capital expenditures in test year 2025 over the prior year (from $6.149 billion in 2024 to $7.393 billion in test year 2025).[1754] This is a much larger increase than has been experienced in prior cases. For example, in the previous GRC, SCE proposed to increase the $5.110 billion in 2020 capital expenditures to $5.601 billion for the test year 2021.[1755] Thus, SCE is worried that the weighted average of capital additions based on 2024’s lower capital expenditures and 2025’s much high capital expenditures will not be large enough to accommodate SCE’s extremely high budget projections that range from $7.9 to $8.4 billion during the attrition years.[1756] The Commission can eliminate this “problem” by adopting more moderate capital expenditure forecasts for the test year and tempering spending growth during the post-test year period, based on the robust record developed by TURN, Cal Advocates, and other intervenors in this proceeding.

In sum, the Commission should find that TURN’s two-part attrition mechanism meets the objectives of attrition and more reasonably balances the interests of ratepayers and shareholders during the post-test year period than SCE’s. Nonetheless, if the Commission adopts SCE’s approach to capital attrition, the Commission should order the use of national rather than

[1754] Ex. TURN-17 (Yap), p. 6.
[1755] Ex. TURN-17 (Yap), p. 6.
[1756] Ex. TURN-17 (Yap), p. 6.

regional capital escalation indices and should reject SCE's proposed adjustment to test year capital additions to address the "lag".

41.5 The Z-Factor Threshold and Deductible Should Be Increased to Reflect Inflation Since Its Initial Adoption for SCE.

SCE's current post-test year ratemaking (PTYR) mechanism includes a "Z-Factor" mechanism that creates an opportunity for the utility to recovery in rates cost changes associated with exogenous events.[1757] The Z-Factor is subject to both a $10 million "threshold" and a $10 million deductible that applies on a one-time basis to the first year's revenue requirement associated with any approved Z-Factor.[1758]

The Commission should increase the $10 million threshold and deductible figures for Z-Factor purposes to reflect inflation that has occurred since the Z-Factor was first adopted for SCE.[1759] TURN submits that whatever incentive or ratepayer protection was created by $10 million figures in the late 1990s, or even in 2004, when SCE sought to retain the Z-Factor as it shifted from performance-based ratemaking back to cost-of-service ratemaking, is significantly dampened when the same $10 million figures are calculated in 2025 dollars. TURN proposes an increase of 80% (to $18 million) to reflect general inflation since 2000, based on data reported by the Federal Reserve Bank of Saint Louis.[1760] If the Commission instead saw fit to tie the increase to inflation since SCE first sought to have the Z-Factor mechanism applied to cost-of-service ratemaking, it could adopt a slightly lower increase to reflect cumulative inflation since

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[1757] Ex. SCE-07, Vol. 4, pp. 37-38.

[1758] D.04-07-022 (SCE Test Year 2023 GRC), pp. 278-279.

[1759] Ex. TURN-15-E2, pp. 25-26.

[1760] The Federal Reserve Economic Data indicate a cumulative Consumer Price Index increase of approximately 83% for the period from 1/1/2000 through the end of 2023.

2004. The point is that twenty-plus years of inflation may reasonably be expected to dampen any incentive and risk-sharing effect the deductible is intended to serve, and the Commission should take action to remedy that.

The Commission should dismiss SCE's contention that TURN's proposal is "punitive."[1761] The contention would seem to apply equally to SCE's escalation adjustments and post-test year ratemaking proposals and any of the numerous other ratemaking adjustments made to reflect the effect of cumulative inflation. Similarly baseless is SCE's suggestion that the Z Factor should be treated as an outdated element of performance-based ratemaking;[1762] the Z-Factor has been part of SCE's GRC ratemaking since the utility first proposed to include it in the test year 2003 GRC.[1763]

[1761] Ex. SCE-18, Vol. 1, p. 24.

[1762] *Id.*

[1763] D.04-07-022 (SCE Test Year 2023 GRC), pp. 278-279.

42. RESIDENTIAL DISCONNECTIONS AND ARREARAGES

43. COMPLIANCE REQUIREMENTS

44. ACCESSIBILITY ISSUES

45. RESULTS OF FINANCIAL EXAMINATION BY CAL ADVOCATES

46. GRC UPDATE PHASE

47. CONCLUSION

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