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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 2021, among other things, and to Reflect that Increase in Rates.	Application 19-08-013 (Filed August 30, 2019)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

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2.2 AB 1054 Ratemaking Issues

- The provisions of AB 1054 do not change the Commission's obligation to review all wildfire mitigation costs included in this application to determine whether they meet the just and reasonable standard.

3. POLICY

4. AFFORDABILITY

4.1 - Affordability:

- SCE is requesting a 20% increase over 2019 authorized GRC base rates for test year 2021, which is far from affordable, and even SCE acknowledges that its requested rate increases exceed the average rate of income growth in California over the same period. The Commission must, now more than ever before, carefully weigh the value of every dollar requested in this GRC.

4.2 - Disconnections Compliance Report:

- The analysis performed and offered by SCE is inadequate to meet the requirements of D 19-09-020, which directed SCE to analyze the relationship between rate increases, arrearages, and disconnections as part of its 2021 GRC showing, nor does it satisfy SB 598, which required SCE to conduct an assessment of and properly identify the impact of any proposed rate increase in rates on disconnections for nonpayment.
- All other things being equal, the 20% revenue increase requested by SCE is likely to negatively impact affordability for residential customers, and also likely to increase overall disconnections absent specific action by the Commission to protect customers.

4.3 - COVID-19 Issues

- Economic uncertainty driven by the COVID-19 pandemic makes it all the more critical that the Commission ensure that rate increases are only granted when tied to those programs the utility has shown to be strictly necessary and consistent with safe, reliable and affordable service.

5. RISK-INFORMED STRATEGY AND BUSINESS PLAN

- For the next RAMP and GRC, the Commission should require SCE to transparently address affordability and cost-effectiveness, identifying how these principles are incorporated in SCE's proposals.

- For the next RAMP and GRC, to the extent SCE continues to rely on different models for the GRC and RAMP risk analysis, the Commission should require SCE to explain and justify any divergence between the two models.
- For the next RAMP and GRC, the Commission should direct SCE to calculate likelihood of risk events using a specified period of time.
- For the next RAMP and GRC, the Commission should direct SCE to include egress in risk consequence calculations.

6. DISTRIBUTION GRID

7. METER ACTIVITIES

8. TRANSMISSION GRID

9. SUBSTATION

10. GRID MODERNIZATION, GRID TECHNOLOGY, ENERGY STORAGE

10.2.1 - Engineering and Planning Software Tools:

- TURN supports the analysis and recommendation by Public Advocates Office that the Commission authorize $0 for Engineering and Planning Software Tools for both 2020 and 2021, which reflects a reduction of $25.145 million in 2020 and $27.213 million in 2021.

10.2.2 - Grid Management System:

- SCE seeks an additional $60 million for the same project that the Commission approved in the 2018 GRC. SCE has not established why it is reasonable to increase the forecast by 42% for the same work. TURN supports the recommendation of the Public Advocates Office, which reflects a reduction of $0 million in 2020 and $10.155 million in 2021.

10.2.3 - Automation:

- TURN recommends reductions in spending by deploying remote controlled switches ("RCS") and remote fault indicators ("RFI") on circuits instead of remote intelligent switches ("RSI") and/or more circuit ties as proposed by SCE, which would achieve similar functionalities and benefits more cost-effectively. TURN's recommendation represents a reduction of $24.918 million in 2020 and $15.154 in 2021.

10.2.5 - Alleged Benefits of Grid Modernization:

- The Commission should be cautious about the alleged benefits of Grid Modernization investments. Any benefits from a future "Marketplace for DERs" are entire speculative, and reliability benefits of Grid Modernization are likely inflated. The Commission should require a more robust benefits showing in future GRCs.

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11. LOAD GROWTH, TRANSMISSION PROJECTS, AND ENGINEERING

12. NEW SERVICE CONNECTIONS AND CUSTOMER REQUESTED SYSTEM MODIFICATIONS

12.1 - New Meter Connections:

- The Commission should find that SCE has failed to demonstrate the reasonableness of its forecast of residential new meter connections, which is driven by Moody's overly optimistic forecast of housing starts. The Commission should instead adopt TURN's forecast, which is lower than SCE's by 5,883 meters in 2021, 8,438 meters in 2022, and 9,159 meters in 2023. Using TURN's forecast of new meter connections would reduce associated capital expenditures by $76,711 million (Nominal $) over the three-year period. The Commission should adopt TURN's proposed capital budgets for 2021, 2022, and 2023.

- The Commission should adopt TURN's forecast of commercial new meter connections, agreed to by SCE in rebuttal testimony, and associated capital expenditure budgets for 2021, 2022, and 2023. TURN's forecast is lower than SCE's original forecast by 2,092 meters across the 2021-2023 period and reduces associated capital expenditures during that time by $40,144 million (Nominal $).

- The Commission should adopt TURN's recommendation, agreed to by SCE, that SCE develop a new methodology for forecasting commercial new meter connections for the next GRC

12.2 - Rule 20A Conversions:

- TURN recommends a reduction of $31.1 million for this GRC cycle because there is a balance of $31.1 million in the Rule 20A Balancing Account. SCE has accepted TURN's recommendation in its rebuttal testimony.

- TURN supports SCE's proposal to maintain the one-way balancing account for Rule 20A.

13. POLES

14. VEGETATION MANAGEMENT

14.3 - Wildfire Vegetation Management (a.k.a. Hazard Tree Management Program)

- SCE's forecast for removal of green, living trees under HTMP should be reduced by 80% to an average of 5,000 removals in 2021-2023 – and 4,000 removals in 2021. This reduces SCE's 2021 forecast for this program by $35.45 million to $20.74 million. In addition, SCE should be directed to include the impact of lost greenhouse gas reduction benefits in its risk assessment model that determines whether green, living trees should be removed under HTMP. TURN does not take a position in this brief on SCE's pre-Update forecasts for its other three vegetation management programs. TURN presents its position on SCE's vegetation management Update testimony in Section 45.

15. WILDFIRE MANAGEMENT

15.1 Wildfire Mitigation: Overview

- Effective wildfire mitigation requires a diverse portfolio of mitigations. TURN does not oppose the SCE forecasts for Enhanced Overhead Inspections and Remediations, Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.
- TURN recommends that the Commission direct SCE to study how costs can be reduced while maintaining a consistent level of safety in locations where multiple wildfire mitigations are deployed.

15.2 Wildfire Management, Covered Conductor

- The Commission should reject the SCE-proposed scope and pace of covered conductor and adopt the TURN proposed scope for covered conductor deployment. TURN proposes deployment of 2,500 miles of covered conductor at a total budget of $642.796 million over the rate case period.
- For the purposes of the pole replacement budget, the Commission should adopt TURN's assumption that in only 25% of cases SCE will need to install a composite pole and otherwise replacement poles can use pole wrap.
- The Commission should reduce the proposed scope of tree attachment replacement consistent with TURN's proposed scope of covered conductor deployment.

15.4 Wildfire Management, Distribution Fault Anticipation

- The Commission should reject the full deployment of a Distribution Fault Anticipation program, without prejudice, pending a report on the results of SCE's pilot program.

15.5.1 Wildfire Management, Vertical Switches

- SCE's request to replace all vertical switches on its system is unjustified, and the Commission should reject SCE's proposal. SCE should instead replace vertical switches based on the results of inspections.

15.10 Wildfire Management, Retirement of Assets Due to Wildfire Mitigation Work

- To protect ratepayers from the adverse rate impacts resulting from the early retirement of assets, the Commission should remove the replaced asset from ratebase or, at a minimum, set the return associated with the replaced asset at no higher than the cost of debt.
- The Commission should require SCE to track and report on prematurely removed assets annually.

16. T&D OTHER COSTS AND OTHER OPERATING REVENUE

17. CUSTOMER INTERACTIONS

17.2.1 - Billing Services:

- SCE does not need an increase in FTEs for Billing because SCE expects to perform 42% less, not more, manual billings in 2021 compared to 2018. TURN recommends a reduction of $1.878 million for bundled accounts and a reduction of $2.843 million for CCA Accounts, totaling $4.721 million.
- SCE's repeated arguments for policy adjustments funding should be rejected because SCE once again fails to demonstrate why ratepayers should pay for SCE's errors. TURN recommends a reduction of $0.242 million.

17.2.3 - Credit and Payment Services:

- Given the undisputable facts that the mix of electronic payments has been increasing since 2014 and average cost per payment has been steadily decreasing every year since 2014, the Commission should reject SCE's unsupported and unreasonable request to increase the labor expense by 7.5%. TURN recommends using base year recorded as the expense, which results in a reduction of $0.637 million.
- In its rebuttal testimony, SCE agreed with TURN and Cal Advocates that its forecast should be reduced by $0.200 million to account for the closure of the Rural Offices. SCE further agreed to correct an error with regards to CheckFreePay services and reduce its forecast by $0.668 million. TURN supports both revisions.

17.2.4 - Uncollectible Expense:

- SCE originally requested an uncollectible expense rate of 0.191%, and TURN noted that the estimate was unrealistic and exaggerated. However, through discovery later conducted by TURN, SCE identified an error in its analysis and updated its uncollectible forecast to 0.180%. TURN agrees and supports SCE's updated uncollectible rate of 0.180%.

17.3.1 - Customer Communications, Education, and Outreach:

- SCE's request to add $5.2 million in O&M costs for its AIM effort should be rejected because the project is not cost effective, and SCE has not demonstrated how the effort would provide tangible benefits to ratepayers. SCE also does not identify any cost reductions for its existing analytics and marketing labor costs as a result purchasing additional capability. TURN recommends a reduction of $5.2 million for this program.
- SCE requests an increase of $1.047 million to provide education and communication to business service accounts and mass media buys for increasing awareness for building electrification. TURN recommends a reduction of $1.047 million because SCE has not supported a need to further increase its funding for media buys, and it is able to shift existing media buys to new campaigns.

17.5.1 - Business Account Management:

- SCE requests an increase of $5.161 million labor O&M costs for Business Account Management. SCE's request should be rejected because SCE does not provide any justification for why emerging technologies today require more account manager resources than emerging technologies three years ago. Also, adding resources when overall activities are flattening or declining is unreasonable and not justifiable. TURN recommends a reduction of $5.161 million.

17.5.2 - Digital Operations and Management:

- SCE requests an increase of $0.865 million non-labor O&M expense to support evolving digital channels and optimize digital customer experience. By every possible measure, SCE's digital operations and management has greatly improved customer engagement. The current funding level is working well, and SCE does not justify why it is not able to perform any needed improvements using the current non-labor funding level. TURN recommends a reduction of $0.865 million.

17.5.3 - Customer Contact Center Capital:

- In its rebuttal testimony, SCE for the first time seeks authorization for $5.193 million of capital expenses to upgrade its Interactive Voice Response platform, claiming that the costs were inadvertently not included in its direct testimony. Not only did SCE have plenty of time to update its testimony but failed to do so, SCE also readily admits that it did not perform a cost benefit analysis for the project. Ratepayers should not fund a project that even SCE has not determined the benefits would outweigh the cost. TURN recommends a reduction of $5.193 million for this project.

17.6.1 - Customer Experience Management:

- SCE requests an increase of $0.659 million of O&M expense for Customer Experience Improvement. SCE's request should be rejected because it is already conducting these activities currently, and it has not supported the need for an increase. TURN recommends a reduction of $0.659 million.

17.6.2 - Business Account Management Services:

- SCE requests an increase of $1.151 million for Hydraulic Services. The Commission should reject this reasoning because GRC funding should not be increased because SCE plans to reduce spending in EE. SCE later reveals, for the first time, that these activities can no longer qualify for EE funding due to the lack of EE savings attributable to Hydraulic Services. Lastly, an examination of historical pump test numbers reveals that activity levels have not increased and therefore increased funding would be unreasonable. TURN recommends a reduction of $1.151 million.

17.6.3 - Customer Programs Management:

- SCE requests an increase of $0.458 million in labor O&M to support the increased NEM application volume. The Commission should reject SCE's unrealistic forecasts for NEM because SCE similarly produced unrealistic forecasts in the 2018 GRC. In fact, the recorded NEM applications turned out to be less than half of what SCE forecasted. The Commission should reject SCE's similar attempt here and adopt a reduction of $0.458 million.

17.6.4 - Transportation Electrification:

- SCE requests an increase of $3.566 million for Transportation Electrification ("TE"). SCE's request should be rejected in its entirety because SCE already receives funding in other TE proceedings, and the activities described in SCE's testimony are very similar to activities in other TE proceedings. Furthermore, SCE engages in these activities today, and the existing level of funding already led to tremendous growth in TE. SCE has not justified why an increase is necessary. TURN recommends a reduction of $3.566 million.

17.7.1 - Service Guarantees:

- The Commission has denied ratepayer funding for this program in five consecutive GRCs, yet SCE continues to repeat the same arguments that have been rejected. Things have not changed, and having ratepayers fund this compensation to customers would diminish SCE's incentive to meet its service goals. Therefore, the Commission should once again reject ratepayer funding for this program. TURN recommends a reduction of $0.985 million.

18. BUSINESS CONTINUATION

18.1 - Seismic Assessment and Mitigation Program:

- The Commission should reduce SCE's forecast for Business Continuation capital expenditures for the Seismic Assessment and Mitigation Program by $26.511 million to address SCE's over-forecasting of costs for capital projects related to seismic mitigation projects in the transmission substation mitigation and at non-electric facilities categories.

19. EMERGENCY MANAGEMENT

20. CYBERSECURITY

21. PHYSICAL SECURITY

22. GENERATION

22.2.1 - Borel Hydro O&M:

- TURN recommends an adjustment to SCE's O&M forecast to reflect the latest year of recorded cost data (2018) rather than using a five-year average, resulting in a reduction of $0.242 million for non-labor costs. SCE accepted this recommendation.

22.2.2 - San Gorgonio decommissioning costs:

- TURN recommends removing the forecasted $6.565 million in costs from hydro capital and permanently disallowing the recovery of costs associated with decommissioning the San Gorgonio hydroelectric project based on the fact that SCE has requested, and received, funding for this project in four prior GRCs without performing the identified scope of work.

- If the Commission does not adopt TURN's proposed disallowance of San Gorgonio decommissioning costs, it should decline to approve the current forecast because there is an extremely low likelihood that the specific scope of work described in SCE's application will be performed during the current GRC cycle.

22.3 – Mountainview:

- TURN recommends removing a $54 million capital expenditure for turbine rotor replacement that SCE deems "highly unlikely". SCE does not oppose this recommendation.

- TURN recommends an O&M reduction of $0.822 million to account for lower expected payments under the Contract Service Agreement. SCE does oppose this recommendation.

- • TURN recommends an O&M reduction of $0.158 million to incorporate the correct escalation rate for Contract Service Agreement. SCE adopted this recommendation.

22.5 - Fuel Cells:

- TURN recommends reducing O&M by $0.018 million to prevent double counting of 2014-2017 facilities charges for interconnections. SCE does oppose this recommendation.

22.6 – Catalina:

- TURN recommends an O&M reduction of $0.103 million to remove an atypical outage that occurred in 2016. SCE does oppose this recommendation.
- TURN urges the Commission to decline to authorize $34.3 million in capital spending ($25.486 million between 2019-2021) for the Catalina repower project given the low likelihood that any new generation will be in service by the end of 2021 and the importance of considering alternatives that would reduce the need for new diesel generation.
- TURN proposes that SCE be required to submit proposals for Catalina repowering in the Integrated Resources Planning docket and affirmatively demonstrate, in its next GRC, the full consideration of alternatives to diesel generation and the pursuit of a repowering strategy that minimizes both costs and environmental impacts.

22.7 - Palo Verde:

- TURN recommends reducing O&M by $1.516 million to ensure consistency with the most recent budget forecast provided by owner-operator Arizona Public Service.
- TURN recommends reducing O&M by $0.139 million by assigning 50% of Nuclear Energy Institute membership dues to shareholders consistent with prior Commission Decisions.
- TURN proposes crediting ratepayers with $0.474 million of Other Operating Revenues and urges the Commission to reject SCE's proposal to reclassify longstanding water sales revenues as Non-Tariff Products and Services.

23. ENERGY PROCUREMENT

24. ENTERPRISE TECHNOLOGY

25. OU CAPITALIZED SOFTWARE

26. ENTERPRISE PLANNING & GOVERNANCE (NON-INSURANCE)

26.1.2 – Participant Charges and Credits:

- TURN endorses the Cal Advocates recommendation to use a 5-year historical average of participant charges relating to pensions and benefits. TURN recommends an additional $0.255 million reduction to participant charges relating to Administrative and General costs based on a lower level of proposed O&M spending at Palo Verde (see Section 22.7).

27. INSURANCE

27.1 - Liability Insurance (Wildfire):

- The Commission should authorize rate recovery of 50% of the wildfire liability insurance costs found reasonable for the 2021 test year, based on allocating SCE's insurance costs equally between the utility's ratepayers and shareholders.
- The Commission should adopt a forecast of $410.6 million for the costs of obtaining $1 billion of wildfire liability insurance for 2021, while retaining SCE's existing opportunity to seek rate recovery of above-authorized costs through the WEMA and a future showing of reasonableness.
- The Commission should decline to take any position on catastrophe bonds, self-insurance, or any other "alternative risk transfer instruments," as SCE's showing on such topics is inadequate to establish reasonableness.

27.4 - Proposed Accelerated Recovery of Wildfire Insurance-Related Regulatory Asset:

- The Commission should deny SCE's request to increase its test year 2021 revenue requirement by $19 million to accelerate recovery of capitalized wildfire insurance costs in order to comply with a FERC ruling that makes clear no such action is necessary.

28. EMPLOYEE BENEFITS

28.2 & 28.3 - Executive Benefits:

- The Commission should remove Executive Benefits for all employees in positions of Vice President or higher from the GRC forecast, resulting in a reduction of $2.376 million from SCE's executive benefits forecast, corresponding to a recommended forecast of $13.166 million.

28.4 - Executive Compensation:

- Consistent with the direction in Senate Bill 901, prohibiting IOUs from recovering "any annual salary, bonus, benefits, or other considerations for any value, paid to an *officer* of an electrical corporation," the Commission should adopt TURN's primary recommendation, to remove most of the labor forecast, $8.224 million, and the portion of non-labor expense, $5.105 million, that is composed of the Shared and EIX officers forecast. The Commission should reduce SCE's Executive Compensation forecast of $18.113 million by a total of $13.329 million.

- 28.4.4 Executive Incentive Compensation: To the extent that the Commission does not adopt TURN's primary recommendation, TURN's secondary recommendation regarding the Executive Incentive Program (EIC) program for executives is addressed in Section 28.4.4, and recommends a reduction to the target cost of the EIC's financial goal and of lobbying goals on the basis that achievement of the goals primarily benefits shareholders. The Commission should reduce SCE's EIC request by 50%, for a total reduction of $1.133 million.

28.5 - Long-Term Incentives:

- Consistent with its longstanding practice, the Commission should deny rate recovery of the costs of long-term incentives in the form of stock options and remove SCE's $11.602 million LTIP forecast.

28.6 - Short-Term Incentive Compensation:

- The Commission should reject SCE's proposal to increase its STIP to labor cost ratio by 70%. Instead, the Commission should adopt the same ratio of 12.11%, which results in a reduction of $77.4 million. In addition, ratepayers should not pay for metrics and goals that primarily benefit shareholders, and the Commission should adopt a reduction for metrics and goals that primarily benefit shareholders, including the financial measure metrics and the lobbying related metrics, which total $51.8 million. Thus, TURN recommends a total reduction of $129.1 million.

- The Commission has repeatedly noted that benefits from incentive compensation accrue to both shareholders and ratepayers. TURN recommends that the Commission consider a formal policy of sharing STIP costs between shareholders and ratepayers for measures that benefit them both.

29. EMPLOYEE TRAINING & SUPPORT

29.1 - OU Support Services:

- The Commission should reduce SCE's forecast by $3.493 million and adopt an O&M forecast of $29.323 million (i.e., $21.591 million, labor; $7.732 million, non-labor) to correct SCE's double counting of escalation in the labor forecast and to remove the speculative non-labor cost increases ($2.204 million) that SCE has admitted will not materialize.

30. TOTAL COMPENSATION STUDY

31. ENVIRONMENTAL SERVICES, AUDITS, ETHICS & COMPLIANCE, AND SAFETY PROGRAMS

32. ENTERPRISE OPERATIONS

32.1 - Facility & Land Operations

- The Commission should adopt TURN recommendation to reduce SCE's capital forecast for Infrastructure Upgrades by $82.874 million by reducing SCE's forecast for the Blythe Service Center, and disallowing SCE's request for the following three Infrastructure Upgrade projects: (1) Santa Barbara Service Center, (2) T&D Training Center, and (3) Vehicle Maintenance Facilities, as SCE has failed to establish the reasonableness of the proposed projects.

- The Commission should reduce SCE's capital forecast of $15.005 million for substation reliability upgrades to remove the Devers and Rector Maintenance and Test Building projects as SCE failed to spend the authorized amounts for these projects in the last GRC and SCE has failed to substantiate the costs of the projects.

33. POLICY, EXTERNAL ENGAGEMENT AND RATEMAKING

34. GRC-RELATED BALANCING AND MEMORANDUM ACCOUNT PROPOSALS

34.1 - Wildfire Risk Management Balancing Account (WRMBA):

- The Commission should reject SCE's proposal for a new WRMBA in favor of maintaining existing ratemaking mechanisms. If the Commission adopts a new balancing account, it should make it a one-way balancing account, and adopt a companion memorandum account for the purpose of recording any above-authorized spending.

34.2 - Vegetation Management Balancing Account (VMBA):

- The Commission should reject SCE's proposal for a new VMBA in favor of maintaining existing ratemaking mechanisms and practices. If the Commission adopts a new balancing account, it should make it a one-way balancing account, and adopt a companion memorandum account for the purpose of recording any above-authorized spending.

34.3 - Risk Management Balancing Account (RMBA):

- The Commission should reject SCE's proposal for a new RMBA in favor of continuing to have wildfire liability insurance costs recorded in the Wildfire Expense Memorandum Account (WEMA). If the Commission adopts a new balancing account, it should make it a one-way balancing account, and adopt a companion memorandum account for the purpose of recording any above-authorized spending.

35. OTHER RATEMAKING PROPOSALS

36. OTHER OPERATING REVENUE

36.1 Non-Tariffed Products and Services:

- The Commission should order SCE to keep a record of each of the "but for" tests that it conducts for its NTP&S offerings that includes sufficient detail to enable the Commission to meaningfully review the logic and calculations supporting SCE's determination. SCE shall also include the test records as workpapers as part of its next GRC application.

- The Commission should order SCE to keep time logs and other appropriate records of its NTP&S offerings' use of ratepayer funded utility resources that includes sufficient detail to enable the Commission to meaningfully review the use of those resources. SCE shall also include time logs and other records as workpapers as part of its next GRC application.

- The Commission should order that, in SCE's next GRC, the Commission intends to review the "but for" tests and SCE's use of ratepayer funded utility resources for its NTP&S offerings. If the Commission determines that costs were inappropriately treated as not "incremental" or otherwise borne by ratepayers, the Commission should disallow those costs. The Commission should also make clear that it will consider modification of the revenue sharing mechanism in the next GRC.

37. RATE BASE

37.2 - Electric Plant, Reserve and Depreciation Expense:
37.2.1 - Aged Poles:

- The Aged Pole disallowance, first adopted in the 2015 GRC and maintained in the 2018 GRC, should remain in effect through this GRC cycle, as the prematurely replaced poles would likely have remained in service through 2024-2025.

37.3.1 – Working Capital - Lead Lag Study

37.3.1.3 - Goods and Services:

- The Commission should adopt a 2021 PO payment lag forecast of 45-days and adjust SCE's working cash downward by $15.391 million because the timing of when payments are released to vendors is entirely in SCE's control, and SCE's standard payment term is 60 days, not 45 days.

37.3.1.4 - Depreciation Expense:

- TURN recommends a reduction of $89.149 million in SCE's working capital request based on increasing the depreciation expense payment lag days from zero to 15.2 days, consistent with the fact that depreciation is recognized and "paid" monthly. A lag of zero days would unnecessarily increase revenue requirements by nearly $90 million, which enriches shareholders at the expense of ratepayers.

37.3.1.6 - Taxes Based on Income:

- TURN recommends a working cash requirement reduction of $265.945 million based on increasing the income tax payment lag days to align with the reality that SCE has not paid federal or state taxes since before the last 2018 GRC cycle, and is unlikely to have any actual tax burden during the 2021 rate case cycle.

37.3.2 - Customer Deposits:

- The Commission should continue to require SCE to offset rate base by customer deposits because SCE's customer deposits remain a permanent source of low-cost capital. Even SCE itself forecasts a customer deposit balance of $222 million by 2023, but it is seeking a ratemaking treatment that pretends SCE would hold $0 of customer deposits beginning 2021. Not only would this ratemaking treatment be unrealistic, it would also unreasonably and unjustly increase costs to ratepayers.

37.3.3.1 – Palo Verde Materials and Supplies:

- TURN recommends reducing materials and supplies inventory by $2.934 million to reflect the 13-month average inventory included in the budget provided by APS to Palo Verde co-owners. SCE does not oppose this recommendation.

38. DEPRECIATION AND DECOMMISSIONING

38.1 - Overview:

- The Commission should not adopt an increase of any amount to SCE's depreciation or decommissioning expenses in this GRC as a step toward mitigating the overall revenue requirement increase that is likely to result for test year 2021 and remain in place for each of the attrition years to follow.

38.2 - T&D Net Salvage:

- TURN's primary recommendation is that the Commission adopt no change to existing net salvage rates as a step toward mitigating the revenue requirement impact of SCE's overall GRC request. In the alternative, TURN's depreciation analysis relied on the Commission's past commitment to "gradualism" and recommended smaller changes to the currently authorized net salvage rates, resulting in a $50 million increase to the annual depreciation accrual, rather than the $199 million increase SCE proposed.

38.3 - T&D Average Service Life:

- The Commission should adopt TURN's proposed service life adjustments to eight of SCE's transmission and distribution accounts.

38.4 - Small Hydro Decommissioning:

- The Commission should adopt TURN's proposed accrual amount for purposes of initiating accrual of decommissioning costs for small hydroelectric generation facilities.

38.5 – Decommissioning Escalation:

- The Commission should calculate generation decommissioning expense in 2023 dollars, consistent with the outcome adopted in SCE's test year 2018 GRC.

38.6 - Perris Decommissioning:

- TURN recommends limiting decommissioning cost recovery to $3.81 million based on costs incurred through the end of June and the absence of any support for additional expenses.
- TURN proposes removing Perris from mass property treatment and, consistent with precedents governing abandoned plant, authorizing the recovery of remaining net plant over six years with no return on equity or debt.
- TURN recommends that the Commission direct SCE to pursue any legitimate damage claims against the facility owner with 95% of the proceeds credited to ratepayers.

38.7 - Palo Verde Interim Retirements:

- TURN recommends reducing forecasted interim retirements by $1.767 million based on the use of a 7-year historical average that excludes an unusually large capital project in 2011.

38.8 - Fuel Cell Generation:

- TURN recommends that the Commission approve a 15% contingency factor for decommissioning costs rather than the 25% used by SCE, thereby reducing the forecasted cost from $3.0 million to $2.72 million (a difference of $0.283 million).

- TURN recommends a reduction of expected decommissioning costs by 50% (to $1.36 million) based on the absence of any demonstration that the facilities are likely to be decommissioned in the near future. In combination with TURN's first recommendation, this proposal would reduce SCE's annual revenue requirement from $1 million to $0.453 million.

38.10 – Other Issues:

- SCE should be directed to conduct updated decommissioning studies for its next GRC.

39. TAXES

40. OTHER RESULTS OF OPERATIONS ISSUES

41. POST TEST YEAR RATEMAKING

- The Commission should deny SCE's proposed post-test year ratemaking mechanism as it is too generous to shareholders, and instead adopt TURN's approach, which more appropriately balances shareholder need for relief and ratepayer need for moderation in the growth of rates. TURN's approach includes (1) escalating expense during the attrition period using CPI-U, or alternatively, CPI-U plus 50 basis points; (2) determining capital additions for wildfire mitigation and residential and commercial new service connections based on a specific capital budget adopted for the test year and each attrition year; and (3) basing all other non-wildfire-related capital additions on adopted test year non-wildfire related capital additions with zero escalation in each of the attrition years.

42. COMPLIANCE REQUIREMENTS

43. ACCESSIBILITY ISSUES

44. RESULTS OF FINANCIAL EXAMINATION BY CAL ADVOCATES

45. GRC UPDATE PHASE

45.1 Vegetation Management Update Testimony

- The Commission should conclude that: (1) SCE's testimony exceeds the scope of proper Update testimony and should not be addressed in this GRC proceeding; and (2) SCE may seek to recover costs for its VM programs in excess of the forecasts adopted in this case -- based on the pre-Update record -- via the memorandum account and processes set forth in Public Utilities Code Section 8386.4b). Alternatively, if the Commission (incorrectly) determines that SCE's Update testimony is appropriate for consideration and decision based on the truncated Update record in this case, then, for the reasons provided in Section 14.3, SCE's 2021 Update forecast for HTMP should be reduced to reflect removal of 4,000 (not 20,000) living trees. Under this alternative recommendation, SCE's 2021 Update forecast would be reduced from $77.125 million to $32.818 million, a reduction of $44.306 million.

46. STIPULATIONS AND POST-FILING CONCESSIONS

47. MISCELLANEOUS/OTHER ISSUES

48. REQUEST FOR ORAL ARGUMENT

49. CONCLUSION

OPENING BRIEF OF THE UTILITY REFORM NETWORK

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 2021 General Rate Case (GRC) of Southern California Edison Company (SCE).

1. SUMMARY OF ISSUES AND ARGUMENT

TURN's summary of issues and argument is as presented in the Summary of Recommendations that is included as a preface to this brief.

2. LEGAL ISSUES

2.1 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.[1] 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, [the utility] must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. [The utility] 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 [the utility's] showing. As the applicant in this rate case, [the utility] has the burden of proving that each of its proposals is reasonable.[2]

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

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

Thus, the Applicants have the burden of affirmatively establishing the reasonableness of all aspects of their application. 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.[3]

The Commission must be attentive to important corollaries of the fundamental point that the utility bears the burden of proof. First and foremost, "[t]he presumption is that the existing rates are reasonable and lawful."[4] If the utility does not provide adequate support for its requested increase with regard to any element of its revenue requirement, the current amount should remain in effect. 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.

Second, in placing the burden of proof on utilities with respect to reasonableness issues, the Commission is mindful of the huge information advantage they enjoyed in such proceedings:

> There is a natural litigation advantage enjoyed by utilities in that we must rely in significant part on their evidence and experts; this advantage reinforces the importance of placing the burden of proof in ratemaking applications on the applicant utilities.[5]

As is usually the case in utility rate cases, SCE enjoys an overwhelming advantage compared to the other parties concerning knowledge of its utility system operations, including the efficiency – or lack thereof – of its operations. As the Commission has recognized, this "litigation

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

[4] D.00-02-046 (PG&E test year 1999 GRC), 2000 Cal. PUC LEXIS, *57, citing *Southern Counties Gas Company* (1952) 51 CPUC 533; *Citizens Utilities Company* (1953) 52 CPUC 637; *Park Water Company* (1955) 54 CPUC 498.

[5] D.05-12-020, p. 5.

advantage" underscores the fairness of imposing and strictly enforcing the burden of proof on SCE.

Finally, the Commission currently requires utilities to meet the "preponderance of the evidence" standard of proof in rate cases.[6] Under that standard, 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."[7]

2.2 AB 1054 Ratemaking Issues

Assembly Bill (AB) 1054, enacted in 2019, creates the possibility that some portion of the capital expenditures reviewed and authorized in this proceeding may be the subject of a future securitization application. The statute "prohibits large electrical corporations from including in equity rate base their share of the first $5 billion spent statewide on fire risk mitigation capital expenditures."[8] If the Commission determines that certain conditions are met, the utility may be permitted to securitize the capital expenditures for which an equity return is prohibited. SCE's share of the $5 billion figure is $1.575 billion,[9] and it expects to reach this "statutory cap" by early 2021.[10] SCE also states that "there is no revenue requirement associated with the $1.575 billion included in SCE's requested revenue requirement in this GRC."[11]

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

[7] D.08-12-058, p. 19 (citing Witkin, Calif. Evidence, 4th, Vol. 1, 187).

[8] Ex. SCE-7, Vol. 1 (Tessler), p. 3:7-9.

[9] Ex. SCE-7, Vol. 1 (Tessler), p. 3:11-12.

[10] Ex. SCE-12, Vol. 1 (Payne Rebuttal), p. 6, fn. 7.

[11] Ex. SCE-7, Vol. 1 (Tessler), p. 4:8-10.

The Commission must recognize that the enactment of AB 1054 does not alter in any way the need for it to review SCE's proposed spending and authorize only those portions the utility demonstrates to meet the "just and reasonable" standard. Nothing in AB 1054 suggests otherwise; in fact, the new statute specifically reiterates the need for a Commission finding that costs are "just and reasonable pursuant to Section 451" as a predicate to any utility securitization application.[12] Whether or not the capital expenditures fall within SCE's $1.575 billion "cap" or might be financed through securitization is irrelevant to the Commission's obligations here. By authorizing only those wildfire mitigation costs that meet the just and reasonable standard, the Commission will ensure that ratepayers receive the full benefit of the new statute.

3. POLICY

The Commission certainly has its work cut out for it in the test year 2021 GRC for SCE. For starters, there is the magnitude of SCE's requested increase – even excluding related increases waiting in the wing, SCE seeks an increased revenue requirement of $1.288 billion, which would represent a more than 20% increase to the utility's base rates.[13] Such a request would challenge the Commission's ability to achieve affordable rates for many of SCE's customers even if the utility's service territory were in the midst of an economic boom; instead, the request coincides with a pandemic that has caused public health and economic distress of unparalleled proportions. And a substantial portion of SCE's requested increase is tied to

[12] Cal. Pub. Util. Code § 850(a)(2).

[13] Ex. SCE-52A 2E (SCE Update Testimony), p. 1. This figure excludes the $500 million associated with "Track 2" of the GRC, representing recorded costs from 2018-2019 that SCE also seeks to recover in its 2021 revenue requirement.

activities and programs that are among California's highest priorities, mitigating the risks associated with wildfires.

TURN submits that the circumstances call for heightened attention to certain characteristics of SCE's request. The Commission must recognize that a very substantial portion of SCE's overall request is the product of SCE having chosen to include increases for activities or costs that the utility could have and perhaps should have excluded or removed from the request.

- Approximately $200 million of SCE's total requested increase is tied to changed net salvage rates used to calculate depreciation expense. In the test year 2009 GRC, the Commission acknowledged the Division of Ratepayer Advocates (DRA) point that net salvage is an area where the overall requested rate increase may be mitigated with no risk or adverse impact to the utility and its shareholders, and opted to do just that, choosing to retain the previously adopted net salvage rates.[14]
- Had SCE respected the outcomes from a long line of GRC decisions, it would have sought ratepayer funding of no more than 60% rather than 100% of its forecast for Short Term Incentive Compensation Program (STIP), and omitted its request for Long Term Incentive compensation for executives (that is, stock options), lowering its GRC request by approximately $83 million.[15]

[14] D.09-03-025 (SCE test year 2009 GRC), pp. 179-180.

[15] In D.19-05-020, the Commission permitted ratepayer funding of 40% of the amount found reasonable for STIP (p. 186). Here, SCE seeks ratepayer funding of $178.3 million. 40% * $178 million = $71 million. The Commission has denied ratepayer funding of any amount for Long

- SCE insists that its initial recovery of future decommissioning costs must start at $30 million per year, rather than the lower figures proposed by TURN and the Public Advocates Office (CalAdvocates) that would reduce the 2021 revenue requirement by approximately $20 million.
- SCE proposes to accelerate in three years certain capitalized wildfire insurance costs that were incurred in past years and, under the *status quo*, will be fully recovered over a longer period, a change that adds $19 million to SCE's 2021 revenue requirement.
- By seeking an early end to the Aged Poles disallowance adopted and maintained in the prior to GRCs, SCE would add approximately $15 million to its 2021 revenue requirement.[16]

Thus, the Commission could reduce SCE's requested increase by nearly $340 million simply by maintaining the *status quo* (or, for hydro decommissioning, starting recovery at a lower but still reasonable figure) in areas that would not in any way jeopardize the funding available to provide safe and reliable utility service.

A different set of challenges arises with regard to SCE's proposed funding for its programs and operations with a stronger nexus to its ability to provide safe and reliable service. In those areas,

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Term Incentives since before anyone can remember; SCE is seeking $11.6 million of rate recovery here.

[16] Each of these examples, as well as TURN's recommendation for the specific topic, is more fully discussed in later sections of TURN's Opening Brief. *See* Sections 27.4 (Accelerated Recovery of Wildfire Insurance), 28.4-28.6 (in Employee Benefits), 37.2.1 (Aged Poles), 38.2 (Net Salvage), and 38.4 (Small Hydro Decommissioning).

> The burden is on SCE to not only establish that the proposed work activities are necessary, but also that SCE has prudently examined alternatives before coming to ratepayers to fund the chosen action. The Commission reviews SCE's showing to ensure that SCE is addressing the work in a cost-effective manner.[17]

In SCE's recent GRCs, the Commission has described at some length the importance of SCE meeting this burden in order to obtain approval of its proposals. A recurring theme is the need for a "balancing of interests" that permits rate recovery of only those just and reasonable costs necessary for safe and reliable service.[18] Of late, the Commission has sharpened its focus on the task of balancing safety and reliability risks with minimizing cost impacts, and the challenge of "reaching an outcome consistent with these twin objectives."[19] Thus, for each and every program, SCE must demonstrate:

1) The program is necessary for the provision of safe and reliable service;
2) SCE has considered all available alternatives; and
3) SCE's proposal is cost-effective.

To this end, the Commission has overseen the development of tools to enable the comparison of different programs and their impact on the utility's risk profile. For example, in D.18-12-014 issued in A.15-05-002, the Safety Model Assessment Proceeding, the Commission adopted a settlement that adopts minimum guidelines for a utility risk-based decision-making framework. While this SCE rate case was not subject to the terms of the settlement, the Commission's adoption of this framework and continuing effort to refine it demonstrates the agency's growing

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[17] D.19-11-050 (SCE test year 2018 GRC), pp. 9-10, *quoting* D.12-11-051 (SCE test year 2012 GRC), p. 16.

[18] *Id.*, pp. 9-11, *quoting* D.12-11-051 (SCE test year 2012 GRC) and D.15-11-021 (SCE test year 2015 GRC).

[19] *Id.*, *quoting* D.15-11-021, p. 11.

commitment to achieving outcomes that balance safety and reliability improvements with the cost impacts borne by SCE's ratepayers.

Determining what is truly necessary to achieve an appropriate level of safety and reliability is a difficult task at best, and is made more difficult by the fact that "virtually everything a utility does [has] some nexus to safety and can be deemed to have some safety impact." Therefore, "[i]t is not enough to merely assert that safety would be compromised absent approval of a particular work effort. … [T]he emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent."[20]

An example of a program that presents such balancing of interest challenges is SCE's proposed spending on its covered conductor program, a central element of the utility's wildfire mitigation programs and activities. As demonstrated in Section 15.2 of this brief, SCE's request fails to demonstrate that its proposed covered conductor spending, with a price tag in excess of $3 billion, is appropriately sized to provide safe and reliable service at a reasonable cost. TURN does not dispute that an appropriate level of covered conductor deployment is consistent with achieving the goal of providing safe and reliable service. But the utility failed to size the program in a manner consistent with achieving cost-effectiveness, and has not demonstrated that less costly alternatives would not also achieve that goal, but in a manner that better serves the reasonable rates goal that the Commission has long-recognized is part of the balance it must seek to achieve here.

4. AFFORDABILITY

4.1 Overview

[20] D.14-08-032 (PG&E test year 2014 GRC) , p. 28.

Access to dependable, continuous electric service is foundational to modern American life. Accordingly, the Commission has recognized that "Californians rely on utility services, including electricity, gas, water, and telecommunications, to live and work."[21] The California Legislature declared in SB 598 that living without basic gas or electric utility service "causes tremendous hardship and undue stress, including increased health risks to vulnerable populations."[22] Without energy utility services, families cannot refrigerate groceries, cook regular meals, bathe in warm water, or study at night with the lights on. Access to these essential services is predicated on affordable utility bills.

In Decision 19-05-020 (SCE 2018 GRC), the Commission recognized the importance of affordable bills:

> "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."[23]

The Commission explained the approach it would take in scrutinizing the utility's requests:

> "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

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

[22] SB 598, Sec. 1(c).

[23] D.19-05-020, pp. 18-19 (quoting TURN's Opening Brief).

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."[24]

D.19-05-020 is "the third consecutive SCE GRC where the Commission has emphasized the importance of affordability as a metric for evaluating funding request[s],"[25] stating in SCE's 2012 GRC decision:

"The burden is on SCE to not only establish that the proposed work activities are necessary, but also that SCE has prudently examined alternatives before coming to ratepayers to fund the chosen action."[26]

> "We confirm that the Commission's mandate is specific and requires a balancing of interests to authorize rate recovery only for those just and reasonable costs necessary for safe and reliable service. This requires a hard look at each proposed expense, including whether it is necessary during the coming rate cycle and is appropriately calculated."[27] For this Commission, a key element of finding a charge or rate just and reasonable is whether that charge or rate is affordable.[28]

Beyond addressing the level of rates in the GRC process, the Commission also opened two proceedings to address energy insecurity: 1) Rulemaking 18-07-006, *Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service,* to examine affordability; and 2) Rulemaking 18-07-005, *Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs*, to consider how credit and collections policies can be used to reduce

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24 D.19-05-020, p. 20.

25 D.19-05-020, p. 9.

26 D.19-05-020, p.10 and D.12-11-051, p. 16.

27 D.12-11-051, p. 9.

28 D.19-05-020, p. 11.

customer disconnections for non-payment.[29] These proceedings in conjunction with this GRC allow the Commission to ensure, along with safety and reliability, the widest level of access and affordability for SCE's customers.

However, SCE's GRC request is far from affordable. SCE is requesting a 20% increase over 2019 authorized GRC base rates for test year 2021.[30] Taken together with two attrition years of more than $384 million and $538 million in 2022 and 2023 respectively,[31] this request would require that its ratepayers pay at least $5.225 billion more for electric service over the three years 2021-2023 than if currently authorized base revenue requirements were unchanged.[32] As was the case in its 2018 GRC, SCE is requesting "authority to make significant capital investments during the three-year GRC period, not only for basic maintenance and replacement of equipment on its distribution system, but also additional investments to modernize that system,"[33] including a request for budgeted non-wildfire-related capital spending of $9.7 billion over three years.[34]

The resulting bill impacts are significant for customers. If SCE's full request is granted, customers will face more than 18% of the nearly 20% requested rate increase all in one year,

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[29] *See, e.g.* D.18-12-013 (adopting interim rules to reduce residential disconnections for customers of the large California-jurisdictional energy utilities while the Commission considers longer term solutions).

[30] Ex. SCE-52A 2E (SCE Update Testimony), p. 1. This figure excludes the $500 million associated with "Track 2" of the GRC, representing recorded costs from 2018-2019 that SCE also seeks to recover in its 2021 revenue requirement.

[31] Ex. TURN-03, p. 2, citing SCE Amended Application, p. 4, Table 1.

[32] Ex. TURN-03, p. 2, citing SCE Amended Application, p. 4, Table 1. Calculation: ($1,319 million) x 3 years + ($367 million) x 2 years + ($534 million) x 1 year =$5,225 million.

[33] Ex. TURN-03, p. 2, citing D19-05-020, p. 8.

[34] Ex. TURN-03, p. 2, citing Ex. SCE-07, Vol. 4, p. 32, Table III-5.

2020-2021. In 2021, an "average" residential customer (not taking service on the California Alternate Rates for Energy (CARE) program) would face a $14 increase in their electric bill compared to July 2019.[35] By 2023, the same customer would be paying $24 more per month, or nearly $300 more per year.[36] CARE customers will pay less, but their bills will still increase by almost $200 per year by 2023,[37] due solely to increases in this GRC. Estimated bill impacts for residential customers across different climate zones are summarized below. These electric bills are unaffordable for many Californians.

Estimated Bill Impacts by Climate Zone for Residential Customers[38]

Non-CARE Customer Bills	**2020**	**2021**	**2022**	**2023**
Hot Climate	$149.00	$164.00	$168.30	$174.90
Moderate Climate	$136.80	$150.60	$154.50	$160.60
Cool Climate	$107.70	$118.60	$121.70	$126.50
Non-Care Customers	$124.00	$136.50	$140.00	$145.60

CARE Customer bills	**2020**	**2021**	**2022**	**2023**
Hot Climate	$101.50	$111.90	$114.90	$119.50
Moderate Climate	$87.50	$96.50	$99.00	$103.00
Cool Climate	$64.00	$70.60	$72.40	$75.40
Care Customers	$81.70	$90.10	$92.50	$96.20

Commission's sharp eye and consideration of other options before committing their hard-earned cash."[39]

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[35] Ex. TURN-03, p. 3, citing Notice of Public Forums for Southern California Edison's Request to Increase Electric Rates, p. 1.

[36] Ibid.

[37] Ibid.

[38] Ex. TURN-03, p. 11, citing TURN DR 017, Question 4, parts a-b.

[39] Ex. TURN-03, p. 20, citing D.12-11-051, at 10.

4.2 Disconnections Compliance Report

The California Legislature recognized that the negative impacts of disconnections and energy insecurity are so dire that the Legislature enacted SB 598 in 2017. SB 598 requires the Commission in each GRC to "conduct an assessment of and properly identify the impact of any proposed rate increase in rates on disconnections for nonpayment."[40] SCE's 2018 GRC Decision also directed SCE to analyze the relationship between rate increases, arrearages, and disconnections as part of its 2021 GRC showing.[41] In addition, the Commission specifically directed SCE to include an analysis of the relationship between the agreed-upon metrics to localities and customer class of service.[42] The Commission also directed SCE to engage in a stakeholder process to review its proposed methodology with stakeholders and incorporate their input prior to beginning its analysis.[43]

TURN participated in a number of stakeholder calls and provided written comments to SCE regarding suggestions for their analysis. In both written comments and calls, TURN stated that the analysis should be performed using actual (nominal) rates and bills, not inflation-adjusted rates. Despite TURN's repeated attempts, SCE has refused to conduct an analysis using actual rates.

Based on its analysis using inflation-adjusted rates and bills, SCE asserts, among other things, that: 1) "there is no correlation between disconnections and average rates"; 2) "bill

[40] Ex. TURN-03, p. 20, citing SB 598, Sec. 2, adding Section 718 (b) to the California Public Utilities Code.

[41] Ex. TURN-03, p. 20, citing D.19-05-020, p. 22.

[42] Ex. TURN-03, p. 20, citing D.19-05-020, p. 5.

[43] Ex. TURN-02, p. 22, citing Ex. SCE-07 V05, pp. 1-2.

increases do not cause disconnections over the long term;"[44] and 3) "when performing regressions by climate zone, there is no correlation between disconnections and average bills."[45] In other words, SCE claims that the level of electricity rates and electricity bills is unrelated to the number of disconnections for non-payment in any associated period; rather, disconnections "result mostly from monthly and seasonal fluctuations which bear no relationship to the average bills or rates over time."[46] SCE's purported result is counter-intuitive, a fact which alone should suggest further analysis is warranted.

SCE asserts that it simply did not understand TURN's comments when TURN asked SCE to perform the regression analysis using actual rates.[47] While TURN agrees that SCE's choice to perform only inflation-adjusted analysis is not contrary to any specific requirements in D.19-05-020,[48] it is incomplete given the Commission order to determine if there is a correlation between disconnections and rates. PG&E's disconnections analysis, which was produced prior to SCE's, used actual bill data and demonstrated a correlation between bills and disconnections for CARE/FERA customers. TURN finds the vehemence of SCE's opposition to performing its analysis using nominal data somewhat curious. It is not TURN's role or responsibility to perform SCE's SB 598 analysis.

TURN disagrees with SCE's conclusions on disconnections, and TURN finds that these conclusions are not credible. Graphs presented in SCE's own analysis indicate a clear

[44] Ex. TURN-03, p. 22, citing Ex. SCE-07 V05, p. 9.

[45] Ex. TURN-03, p. 22, citing Ex. SCE-07 V05, p. 13.

[46] Ibid. p. 14.

[47] Ex. SCE-18 Vol. 05 p. 6.

[48] Ex. SCE-18 Vol. 05 p. 6.

relationship between nominal rates and disconnections, which SCE has refused to examine. In addition, since the apparent relationship between nominal rates and disconnections contradict SCE's conclusions that disconnections are wholly unrelated to the level of rates, TURN finds SCE's adamant resistance to this analysis unreasonable.

SCE states in its rebuttal testimony that PG&E found no correlation between rates and disconnection using monthly data.[49] This statement is incorrect and TURN fears that SCE has again mistaken TURN's meaning. TURN stands by its statement. SCE's assertion that residential rates and disconnections are unrelated is inconsistent with the results of PG&E's SB 598 disconnections analysis performed in PG&E's 2020 GRC. In that analysis, PG&E's data showed a strong correlation between the level of monthly bills and the number of disconnections,[50] as seen below. However, SCE chose not to examine the correlation in its own data using nominal rates, and has continued to resist doing so.

For data series: 1) 2010-2017, 2) 2014-2017, and 3) 2015-2017, PG&E's data showed moderate to high correlations in CARE customers. The R^2 values were 0.89, 0.86, and 0.84 for the 2010, 2014, and 2017 data series respectively.[51] In fact, PG&E's data showed a moderate to high correlation between bills and disconnections for CARE/FERA customers in every scenario. The following table summarizes the results of PG&E's data.[52]

[49] Ex. SCE-18 Vol 3, p. 9.

[50] Ex. TURN-03, p. 25 citing PG&E 2020 GRC TURN DR_011, Question 1, Attachment 1.

[51] Ex. TURN-03, p. 25 citing PG&E 2020 GRC TURN DR_011, Question 1, Attachment 1.

[52] Ex. TURN-03-Atch-1, PG&E 2020 GRC TURN DR_011, Question 1, Attachment 1.

Series	PG&E Conclusion	R^2
2014 to 2017 -- Gas Bill vs. Month Avg Gas Total Disconnects	Moderate correlation	0.65837
2014 to 2017 -- Electric Bill vs. Month Avg Electric Total Disconnects	High correlation	0.90984
2014 to 2017 -- Total Bill vs. Month Avg Total Disconnects	High correlation	0.86311
2015 to 2017 -- Total Bill vs. Month Avg Total Disconnects	High correlation	0.84027
2010 to 2017 -- Total Bill vs. Month Avg Total Disconnects	Moderate correlation	0.59221

The correlation between electric bills and electric disconnections for CARE/FERA customers from 2014-2017 is what TURN would consider extremely high. It indicates that more than 90% of the variability in disconnection rates is explained by the level of bills and that the level of bills is a primary driver of disconnections.

TURN finds it unlikely that the relationship between rates and disconnections among PG&E's customers is completely different from SCE's. These results for PG&E, another California electric utility of comparable size, are inconsistent with SCE's assertion that rates/bills and disconnections are unrelated. For PG&E's data to show this level of correlation among the most economically vulnerable customers (whose energy security is most reasonably expected to be tied to rate increases), and SCE to find no relationship at all, defies reason. Certainly, such an anomaly invites the inquiry to which SCE seems most strenuously opposed.

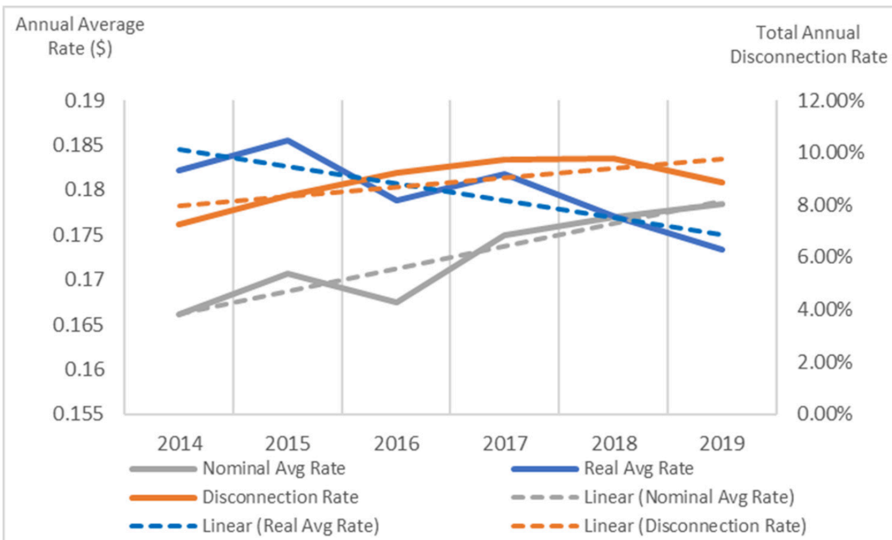
TURN performed its own reality check using annual disconnections for all residential customers over the last 10 years (2009-2019 inclusive) and system average residential rates, as reported by SCE, and found an R^2 value of 0.52.[53] While SCE dismisses TURN's analysis in its

[53] Ex. TURN-03, p. 29, citing Southern California Edison Co, SB 695 Report to the Energy Division Year: 2019, p.5, Table 1.

rebuttal,[54] TURN notes that in the figure SCE itself produced (shown below), the Nominal (Actual) Average Rate and the Disconnection Rate both show upward trends with similar slopes from 2014 through 2018. This is precisely the graphical result one would expect if residential electric rates were indeed correlated with disconnections.[55]

Graph of SCE's Disconnections and Nominal Rates 2014-2018[56]

Figure III-1
Annual Residential Disconnections vs. Real Avg. Rates



Relative to PG&E, SCE's credit and payment practices have resulted in an increasing percentage of disconnections among customers eligible for disconnection.[57] In 2016 (a historic high point for the number of disconnections by all California IOUs), SCE's ratio of total shutoffs

[54] Ex. SCE-18, p. 11.

[55] Ex. TURN-03, p. 23.

[56] Ex. TURN-03, p. 23 citing Ex. SCE-07 V05, p. 8, Figure III-1, Annual Residential Disconnections vs. Real Average Rates.

[57] Ex. TURN-03, p. 19.

to customers with arrearages greater than 60-days was more than 80%, while PG&E's was roughly 60%; SDG&E's was less than 20%.[58]

While TURN does not have the resources (nor the responsibility) to reperform SCE's SB 598 analysis, it believes that SCE's methodology and conclusions are not credible and for that reason do not satisfy the requirements of SB 598. Specifically, SB 598 requires the Commission in each general rate case to "conduct an assessment of and *properly* identify the impact of any proposed rate increase in rates on disconnections for nonpayment."[59] SCE's analysis studiously ignores the obvious comparison of actual rates to disconnections, and its results are both counter-intuitive and different from what PG&E's analysis demonstrates for CARE/FERA customers.

With respect to the impact of this GRC request on disconnects and arrearages, the Commission should find that:

- The analysis performed and offered by SCE is inadequate to meet the requirements of D 19-09-020, which directed SCE to analyze the relationship between rate increases, arrearages, and disconnections as part of its 2021 GRC showing, nor does it satisfy SB 598, which required SCE to conduct an assessment of and properly identify the impact of any proposed rate increase in rates on disconnections for nonpayment.

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[58] Ex. TURN-03, p. 19, citing Living Without Power, Health Impacts of Utility Shutoffs in California, p.9. Customers 60+ days in arrears in Dec. 2016 for SCE, PG&E, and SDG&E are 495,726, 528,230, and 255,240 respectively. The corresponding total disconnections are 402,761, 312,007, and 40,067. Dividing total disconnections by arrearages greater than 60 days results in 81.2% for SCE, 59.1% for PG&E, and 15.7% for SDG&E.

[59] SB 598, Sec. 2, adding Section 718 (b) to the California Public Utilities Code. (Emphasis added).

- That all other things being equal, the 20% revenue increase requested by SCE is likely to negatively impact affordability for residential customers, and also likely to increase overall disconnections absent specific action by the Commission to protect customers.

4.3 COVID Issues

The already profound challenges of maintaining rate affordability are further compounded by the impacts of the COVID-19 pandemic. While the state of the economy in 2021 is not yet known, credible forecasts suggest that significant economic strain resulting from the pandemic will continue well into the rate case period. The Commission cannot rest on the laurels of its work to date to better achieve affordability of utility rates, but must redouble its efforts in the face of Covid-19. One element of such effort must be to ensure that rate increases are only granted where tied to those programs the utility has shown to be strictly necessary and consistent with the need to achieve safe, reliable and affordable service.

In March 2020, approximately six months after SCE filed its rate case application, due to the spread of COVID-19 "much of the world essentially forced all but the most essential economic activities to temporarily grind to a halt."[60] The impacts on California and its residents have been severe. The COVID-19 pandemic and the efforts required to address its spread have put the physical and economic health of SCE ratepayers in peril. The full impact of the COVID-19 pandemic remains uncertain, and "no stakeholder knows to any reasonable degree what the

[60] Ex. SCE-12, Vol 1(Payne), p. 12:17-18.

ultimate impacts of the COVID-19 pandemic will be on SCE's costs, or what will be the timing associated with these impacts."[61]

The Commission has already taken initial steps in response to the economic uncertainty caused by the ongoing pandemic, such as making mandatory a variety of voluntary consumer protection measures, including a moratorium on disconnections for nonpayment, and suspension of late fees and deposits.[62] These programs address the impact of SCE's current high rates, and their need is exacerbated in light of the uncertainty of the California, national and worldwide economic outlook. While such steps are invaluable in helping SCE customers facing the greatest economic distress, they are insufficient to help many others struggling with their energy burden in light of the added pressures brought by COVID-19. Under these circumstances, the regulated utilities and the Commission must seek all reasonable opportunities to avoid making a difficult situation worse. In a GRC, this means finding and making additional adjustments to SCE's forecasts as necessary to ensure SCE is only spending on the most necessary projects. SCE, however, has made no adjustments to its proposed forecasts or the associated rate increases to account for the economic impact of the global pandemic.[63] SCE's failure to make any other adjustments to reflect changed economic circumstances ignores the realities of California's economy and the harsh conditions faced by many of its customers.

SCE may seek to rationalize its choice to treat its GRC forecast as immune from the impacts of COVID-19 by claiming the pandemic's impacts are expected to be of limited duration. During hearings, SCE's Chief Executive Officer Kevin Payne offered his opinion that

[61] Ex. SCE-12, Vol. 1, (Payne) p. 11:8-10.

[62] Ex. SCE-12, Vol. 1 (Payne), p. 12:5-8.

[63] 3 TR 379:17-380:4 (SCE/Payne).

"what we're experiencing right now is not a fundamental economic downturn or things that are fundamental to the operation of the economy."[64] Mr. Payne, however, acknowledges that he "is not an economist."[65] The record evidence makes clear that the economists are less optimistic than Mr. Payne. The June 2020 Economic Forecast produced by the UCLA Anderson School, described as "[t]he leading independent economic forecast providing insight to decision makers in business, academia and government," is more concerned about the extended impact of COVID-19 on the economy.[66] Regarding national recovery, the forecast states: "Despite all of the stimulus being poured into the economy, we anticipate a moderate recovery." When addressing the future of the California economy, the forecast states: "this is a question without a definitive answer."[67] In its view, predicting the recovery of our economy requires "epidemiologists and psychologists more than macroeconomists."[68] Simply put, not even the "leading economic forecast" can currently chart the path of recovery from COVID-19.

While the future is uncertain, the impact of COVID-19 over the last six months is known, and it is substantial. California has already experienced a dramatic downturn in the short term, with unemployment claim numbers of 16.3% in May 2020 as compared to 4.1% in May 2019.[69] Mr. Payne sought to attribute these higher numbers to the "temporary government imposed restrictions on the operation of certain types of businesses."[70] Unfortunately, the forecasts for

[64] 3 TR 337:2-12 (SCE/Payne).

[65] 3 TR 337:2-12 (SCE/Payne).

[66] Ex. TURN 24, p. 7 (UCLA Anderson Forecast, June 2020, p. 1).

[67] Ex. TURN-24, p. 87 (UCLA Anderson Forecast, June 2020, p. California-83).

[68] Ex. TURN-24, p. 28 (UCLA Anderson Forecast, June 2020, p. Nation-24).

[69] Ex. TURN-27, p. 1 (California Labor Market Review).

[70] 3 TR. 335:14-22 (SCE/Payne).

unemployment rates in California demonstrate something more than "temporary." According to the UCLA Anderson Forecast, "The unemployment rate for the 2nd quarter of this year is expected to be 14.6%, and it is expected to decline the balance of 2021. For the entire years 2020, 2021, and 2022 we expect average unemployment rates of 10.5%, 8.2%, and 6.8% respectively."[71] The forecast suggests that nationally, "recovery…won't return [to] the level of output to prior fourth quarter of 2019 peak until early 2023."[72]

The Commission needs to ensure that the outcomes of this GRC serve as much as possible to mitigate the impacts of the COVID-19 pandemic, rather than add to those impacts. It can do so by making every effort to ensure that SCE's requests for increased spending and expanded utility programs focus on work and efforts that are truly essential to the utility's ability to provide safe and reliable service. The 20% rate increase that represents only the partial impact of SCE's proposals for 2021 would only serve to make matters worse for those SCE customers who are already struggling to make ends meet during the pandemic. SCE did not see fit to adjust its request accordingly. It is therefore up to the Commission.

5. RISK-INFORMED STRATEGY AND BUSINESS PLAN

Pursuant to D.14-12-025, SCE includes a discussion of how risk is incorporated in and informs its request. Beginning with the adoption of D.14-12-025 the Commission has sought to encourage additional transparency, accountability, and participation in how the utilities use risk based decision making when developing their proposals.[73] Specifically, large Investor Owned

[71] Ex. TURN-24, p. 90 (UCLA Anderson Forecast, June 2020, p. California-86).

[72] Ex. TURN-24, p. 17 (UCLA Anderson Forecast, June 2020, p. Nation-13).

[73] D.14-12-025, p. 3: "It is our intent that the adoption of these additional procedures will result in additional transparency and participation on how the safety risks for energy utilities are

Utilities are directed to file a Risk Assessment and Mitigation Phase (RAMP) report "describing how it plans to assess, mitigate, and minimize its risks."[74] After stakeholders have an opportunity to provide feedback, the results of the RAMP analysis are to be folded into the utility's GRC filing.[75]

TURN's testimony offers specific recommendations to ensure that SCE's next RAMP and GRC better utilize available risk-based decision-making tools to develop and support its proposal. Specifically, TURN recommends:

- "The utility should transparently address in its RAMP and GRC risk analyses the issues of affordability and cost-effectiveness and identify how the utility has incorporated cost-effectiveness into its proposals.

- SCE's 'top-down' and 'bottoms-up' risk analyses should be validated against each other to ensure consistent and verifiable risk modeling.

- SCE's probability calculations must be calculated over a specific period of time rather than reflect an instantaneous probability.

- SCE's consequence calculations should explicitly score and incorporate egress, or the ability of populations to evacuate in the event of a wildfire."[76]

SCE's failure to propose its programs based on sound and transparent risk-management undermine the ability of the utility to demonstrate that it has provided a forecast that is just and reasonable and will lead to safe, reliable and affordable service.

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prioritized by the Commission and the energy utilities, and provide accountability for how these safety risks are managed, mitigated and minimized."

[74] D.18-12-024, p. 4-5.

[75] D.18-12-024, p. 5.

[76] Ex. TURN-02 (Borden), p.31:11-19.

5.1 TURN's Findings Related to Cost-Efficiency of the Proposed Program are Consistent with the Commission's Conclusions Regarding SCE's Wildfire Mitigation Plan.

As illustrated by SCE's wildfire management proposal (Section 15), SCE has not used risk management tools to demonstrate their rate case proposal is cost-efficient. SCE has not used the risk profile of each of its circuits to tailor its covered conductor proposal to target the highest risk segments (Section 15.2), nor has it provided Risk Spend Efficiencies (RSEs) for all of the proposed programs (Section 15.4). SCE CEO Kevin Payne acknowledges that the utility has not provided RSE calculations for many of its proposed mitigations: "In fact, for many of the things that are in our wildfire mitigation plan, our risk spend efficiency just doesn't really make sense to calculate."[77] Combined, these failures leave the utility unable to demonstrate that its program will result in a cost-efficient use of customer resources.

The issues identified by TURN are consistent with the feedback provided in the Commission's Resolutions adopting the 2020 Wildfire Mitigation Plans (WMP).

- WSD-002 finds that the utilities failures to utilize RSE leave the utilities unable to demonstrate that they "are effectively allocating resources to initiatives that provide the greatest risk reduction for dollar spent."[78] Specifically, WSD-004 finds that SCE's "2020 WMP is lacking in this regard."[79]

- WSD-004 states that "SCE does not show that it is targeting deployment of initiatives to the highest-risk areas."[80]

SCE's failure to calculate RSEs correctly or to develop RSEs for all proposed mitigations undermines the utility's arguments that its proposal is cost-efficient and affordable.

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77 3 TR 346:11-14 (Payne).

78 WSD-002, R.18-10-007, p. 20.

79 WSD-004, R.18-10-007, p. 27.

80 WSD-004, R.18-10-007, p. 27.

5.2 The Commission Should Direct SCE to Implement the Improvements Identified by TURN in its Next RAMP and GRC.

TURN provided feedback to SCE on its RAMP filing, SCE however, chose not to incorporate TURN's feedback.[81] Similarly, SCE has not made adjustments to its GRC proposal given the testimony provided by TURN.[82] In addition to providing correct RSEs on a comprehensive basis, as described above, the Commission should direct SCE to incorporate TURN's other recommendations in its next RAMP and GRC.

The risk analysis underlying SCE's RAMP report and its GRC request are inconsistent. TURN notes: "the RAMP analysis finds that covered conductor and other mitigation measures are expected to reduce[] wildfire risk by 42%, while the GRC analysis assumes covered conductor and other mitigations provide a 60% reduction to wildfire risk."[83] The divergence of the two models undermines the reliability of SCE's risk management approach. TURN acknowledges that the two methods are each used for different purposes,[84] but still argues that rather than contradict one another, the two models should validate one another and the proposed risk mitigation approach. SCE states that "it will continue to seek opportunities to improve the consistency of these analyses."[85] To the extent the utility continues to rely on two different models with two different results, it should be directed to provide testimony in the RAMP and GRC that explains any divergence between the two models, the reasons for the divergence and why the results support, and do not undermine, their proposed programs.

[81] Ex. SCE-01, Vol. 2 (LeMoine), pp. 10:23-11:2.

[82] Ex. SCE-12, Vol. 2 (LeMoine), pp. 10:1-14:10.

[83] Ex. TURN-02 (Borden), pp. 32:15-33:1.

[84] Ex. TURN-02 (Borden), p. 32:11-13.

[85] Ex. SCE-54, p. 89.

SCE uses a "timeless unconditional probability calculation for the Wildfire Risk model" arguing that this is consistent with the SMAP Settlement definition of likelihood.[86] TURN proposed that rather than a timeless probability, the utility should calculate probability on an annual basis, as this better reflects that the likelihood of a circuit to fail varies based on external circumstances (for example, a catastrophic wildfire is less likely during a rainstorm).[87] While SCE accurately characterizes the settlement's definition of likelihood. TURN notes that the Settlement language directing the "Determination of Pre-Mitigation [Likelihood of Risk Event (LoRE)] by Tranche" specifies that "the pre-mitigation LoRE is the probability that a given Risk Event will occur with respect to a single element of a specified Tranche over a specified period of time (typically a year) in the planning period, before a future mitigation is in place."[88]

Finally, TURN recommended that the utility include egress in its calculation of risk consequence in order to help target certain mitigations, like undergrounding, in those areas with less ability to quickly evacuate in a fire.[89] While SCE states it will explore this issue in the future, it does not commit to including egress in the calculation of consequence.[90] TURN continues to believe this is a valuable input to understand the consequences of wildfire which should be included in SCE's consequence score.

6. DISTRIBUTION GRID

6.1 Overview

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[86] Ex. SCE-12, Vol. 2 (LeMoine), pp. 12:11-12, 16-19.

[87] Ex. TURN-02 (Borden), p. 35:4-11.

[88] D.18-12-024, Attachment A, Appendix A, p. A-12, Line 17.

[89] Ex. TURN-02 (Borden), p. 35:20-22.

[90] Ex. SCE-12, Vol. 2 (LeMoine), p.14:6-8.

6.2 Infrastructure Replacement

6.3 Inspection and Maintenance & Capital Related Expenses

7. METER ACTIVITIES

8. TRANSMISSION GRID

9. SUBSTATION

10. GRID MODERNIZATION, GRID TECHNOLOGY, ENERGY STORAGE

10.1 Overview

10.2 Grid Modernization

TURN recommends a total reduction of $102.586 million in reduction of Grid Modernization, including reductions for Engineering and Planning Software Tools, Grid Management System, and Automation, summarized as follows:

Grid Modernization Summary (Capital Expense $000)

	2020 Reduction	2021 Reduction	Total
Engineering and Planning Software Tools	($25,145)	($27,213)	($52,358)
Grid Management System	$0	($10,155)	($10,155)
Automation	($24,918)	($15,155)	($40,073)
Total Grid Modernization Reduction	**($50,063)**	**($52,523)**	**($102,586)**

10.2.1 Engineering and Planning Software Tools: The Commission Should Reject Additional Funding for both 2020 and 2021.

TURN supports the analysis and recommendation by Public Advocates Office that the Commission authorize $0 for Engineering and Planning ("E&P") Software Tools for both 2020 and 2021,[91] which reflects a reduction of $25.145 million in 2020 and $27.213 million in 2021.[92]

[91] Ex. TURN-04, pp. 4-5.

[92] Ex. SCE-54, p. 40.

10.2.2 Grid Management System: The Commission Should Not Authorize an Increase of 42% for the Same Work that It Already Authorized In the 2018 GRC and was Paid for by Ratepayers.

The Commission authorized $135 million in the 2018 GRC for the Grid Management System ("GMS").[93] SCE now seeks an additional $60 million for the same project.[94] Furthermore, SCE expects the entire project that it has scoped so far will cost $247 million,[95] and SCE has indicated that it is already studying further capabilities which will entail further scope and cost. Even if the Commission re-authorizes the GMS, it should not allow SCE to come back with a forecast for the same work that is 42% higher than the previously authorized forecast. TURN thus supports the recommendation of the Public Advocates that the Commission should only authorize $35.724 million and $37.456 million in 2020 and 2021, which reflects a reduction of $0 million in 2020 and $10.155 million in 2021.

The Commission should deny funding on the grounds that these projects were already authorized in prior GRCs. The Commission has established that when a utility requests to charge ratepayers twice for the same work, the utility has the burden to demonstrate that the additional costs are reasonable.[96] SCE concedes that its current proposal includes the same business functionality as outlined in its previous GRC.[97] Thus, ratepayers would not be receiving additional benefits. Furthermore, SCE's choice to move toward a five-year deployment instead

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[93] D.19-04-020, p. 115.

[94] Ex. SCE-02 V4 P1, p. 79, Figure II-21.

[95] Ex. TURN-04, p. 6. This value includes costs for 2016-2023 ($220.796 million) in addition to costs of $26.204 million in 2024 for the scoped Distributed Energy Management System (DERMS). (TURN DR 51-5, Attachment TURN-SCE-051-Q5 Breakdown of ADMS—DERMS Costs.xlsx)

[96] D.19-09-025, p. 101.

[97] Ex. SCE-13 V04 P1, p. 32.

of the previously planned three-year deployment was within its control and therefore not a valid justification for increased costs.[98] Thus, SCE has failed to demonstrate that the additional costs for the same work are reasonable.

10.2.3 Automation: The Commission Should Authorize $8.718 Million for Grid Distribution Automation in both 2019 and 2020.

SCE's proposal for Grid Distribution Automation ("DA") is smaller than it was in the last GRC, but SCE explains that its planned investment is lower due to its focus on wildfire mitigation, and it plans to increase distribution automation spending in future years, forecasting between $245 million and $970 million for distribution automation in 2014-2018.[99] TURN recommends reductions in spending by deploying remote controlled switches ("RCS") and remote fault indicators ("RFI") on circuits instead of remote intelligent switches ("RSI") and/or more circuit ties, and therefore achieving similar functionalities and benefits more cost-effectively.

The following table presents TURN's recommended forecast reduction for Grid DA:

[98] Ex. SCE-13 V04 P1, p. 32.

[99] Ex. SCE-02 V04 P1, p. A-32.

Recommended Reductions for Grid DA Components (1,000s of Nominal$)[100]

Grid DA Equipment	2018	2020 Forecast			2021 Forecast		
		SCE	TURN	SCE > TURN	SCE	TURN	SCE > TURN
Automated Swtiches	N/A	$ 17,545	$ 4,455	$ 13,089	$ 12,032	$ 4,455	$ 7,577
Circuit Tie Upgrades	N/A	$ 13,530	$ 1,701	$ 11,829	$ 9,279	$ 1,701	$ 7,578
RFIs	N/A	$ 3,735	$ 3,735	$ -	$ 2,561	$ 2,561	$ -
Total	**$40,073**	**$34,809**	**$ 9,891**	**$24,918**	**$23,872**	**$ 8,718**	**$15,154**

Given that SCE does not forecast the individual components of Grid DA, these forecasts are representative of the program that SCE proposes to deploy during 2021-2023.

<u>SCE Should Deploy Remote Control Switches and Remote Fault Indicators Instead of Remote Intelligent Switches</u>

A switch is a device that allows load to be transferred from one circuit to another, or allows a circuit segment to be isolated from the rest of the circuit. Using switches to segment circuits and transfer load is the first and primary tool used to reduce the impact of outages. There are two primary types of switches. The RCS can be controlled remotely by system operators but do not collect circuit data (known as telemetry) or allow for automated switching (not to be confused with remote switching) of circuit load. The RIS, or smart switch, can collect real-time circuit information (e.g., current strength and direction, etc.) for use by the GMS and allow for

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[100] Ex. TURN-04, p. 9. The values in the table are based on the costs included for Option 3- +1&+1 Costs in the Reliability DA BCA (‘Option 3- +1&+1 Costs’ tab) (see TURN DR 6-11i, Attachment Reliability Driven DA_BCA_2021GRC.xlsx), scaled for SCE’s forecast set forth in Figure II-25 on p. 104 of Ex. SCE-02V4P1. 2020 values are scaled based on 2021 values from the BCA, and TURN recommends that amount that is indicated for RFIs in 2020 be authorized.

point-to-point communication and computing power to allow the GMS to essentially make and execute a switching plan in real time.

There are two interrelated aspects of switch-derived reliability. First, reliability from switching is derived from the fact that a switch is present and able to transfer load to an adjacent circuit, whether in emergency or non-emergency conditions. More switches per circuit increase reliability because more customers can be switched off the affected circuit, thus reducing the customer minutes of interruption, regardless of whether the switch is "smart" (e.g., RIS) or not (e.g., RCS).

The second aspect of a switch's ability to impact reliability comes from how fast it can be deployed to divert load to an unfaulted circuit. The speed at which a switching plan can be created and deployed is affected by both the type of switch (e.g., RCS or RIS) and the technology (e.g., manual calculations, GMS, etc.) used to create the switching plan. Although the switching-time reduction with RCSs is less than it is with RISs, an RIS costs more than twice as much as an RCS,[101] and SCE would also incur costs to retrofit RCSs with telemetering when existing units are in suitable locations for the Grid DA program. Therefore, given the number of switches that SCE plans to install now and in the future, it is important to consider the benefits and costs of each type of switch.

TURN has rerun SCE's Benefit Cost Analysis (BCA) for Manual Switching by replacing the cost of intelligent switches (including RISs) with the cost of remote switches (including

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[101] Ex. TURN-04, p. 11. O/H units cost $110,000 (Fault Interrupting Switch) and $51,696 (O/H Break Switch); U/G units cost $100,000 (Fault Interrupting Switch) and $110,000 (U/G Load Switch) (see Reliability DA BCA, attached to TURN 6-11-i, 'Cost Summary' tab. RCSs, on the other hand cost about $33,989 for O/H (2018 GRC, TURN DR 54-2 (revised)), after estimating escalation at 2.5% for four years; U/G is about $49,303 after accounting for escalation at 2.5% per year.

RCSs), given that Manual Switching can be achieved by either an RCS or RIS, and crediting the time-saving impacts to Manual Switching procedures from the GMS as a result of process improvement.[102] The results of the Manual Switching procedure with RCS costs, along with the results for Assisted and Automated Switching with RIS cost, are shown below.

BCA Comparison, Manual Switching Solution (Assumes RCS Cost and Functionality) vs. Assisted and Automated Switching (Assumes RIS Cost and Functionality)[103]

	NetComm & Manual FLISR			B			C		
	Remote Switching			Assisted Switching			Automated Switching		
	Benefits	Costs	B/C	Benefits	Costs	B/C	Benefits	Costs	B/C
Option 1: All Load Break Switches (Mids and Ties)									
1:1	**$584**	**$73**	7.98	**$640**	**$87**	7.35	**$666**	**$87**	7.65
2:2	**$816**	**$150**	5.46	**$929**	**$172**	5.39	**$952**	**$172**	5.52
3:3	**$1,002**	**$238**	4.21	**$1,161**	**$273**	4.25	**$1,181**	**$273**	4.33
+1:+1	**$664**	**$84**	7.95	**$754**	**$107**	7.03	**$763**	**$107**	7.12
Option 2: Middle Midpoint Switch is Fault Interrupting (Other Mids and Ties are Load Break)									
1:1	**N/A**	**N/A**	N/A	**$641**	**$99**	6.47	**$667**	**$99**	6.74
2:2	**N/A**	**N/A**	N/A	**$935**	**$183**	5.10	**$971**	**$183**	5.30
3:3	**N/A**	**N/A**	N/A	**$1,170**	**$282**	4.15	**$1,213**	**$282**	4.31
Option 3: All Fault Interrupting Switches (Mids and Ties)									
1:1	**N/A**	**N/A**	N/A	**$641**	**$108**	5.92	**$667**	**$108**	6.17
2:2	**N/A**	**N/A**	N/A	**$935**	**$222**	4.21	**$972**	**$222**	4.38
3:3	**N/A**	**N/A**	N/A	**$1,170**	**$346**	3.38	**$1,351**	**$346**	3.91
+1:+1	**N/A**	**N/A**	N/A	**$760**	**$110**	6.93	**$775**	**$110**	7.06

[102] Ex. TURN-04, p. 11. SCE's Reliability DA BCA does not provide any credit to manual, remote switching for the process improvements that are possible through the GMS. Instead, the company applies an attenuation factor of 0.62 to the reliability benefit it expects from automated decision making in order to estimate the reliability improvement of remote, un-assisted switching, which does not account for the process benefits related to replacing the legacy DMS and its multitude of platforms and systems. (See responses to TURN DRs 48-5a-i (and Attachment TURN-SCE-048 Q5.a-i DA Benefits as a Function of Restoration Time.xlsx, 'Summary' tab) and -13e. Indeed, the 'Summary' tab indicates attenuation factors for Automated Switching (100%), Assisted Switching (95%), and Manual (62%), and indicates for manual switching that it includes no benefit of a GMS – in other words the assumption for Manual Switching is that all of the benefit comes from the presence of more switches and circuit ties.

[103] Ex. TURN-04, p. 12. In this chart, Column A (Remote Switching) assumes the cost and functionality of an RCS, which includes faster switching related to the replacement of the DMS

In the table above, Column A represents the cost and functionality of an RCS-based Manual Switching procedure, which includes the improved functionality of a GMS which provides faster switching. Columns B and C represent the costs and functionality of an RIS-based Assisted Switching and Automated Switching procedure (SCE proposes +1:+1 in Option 3).[104] The results show that 1) the absolute benefits of column A are somewhat lower (by about 9% - 25%) than the absolute benefits of columns B or C, for any option or number of switches; but 2) the B/C ratio for Column A is almost always higher (by about 1% to 40%) due to the lower cost of the RCS.

Given the above, TURN recommends that the Commission should set a forecast that is comparable to the cost of RCS switches at the switch count that SCE forecasts in this case. This amount is $4.455 million, which results in a test year reduction of $7.577 million in capital.

<u>SCE Should Deploy More RFIs Instead of RISs Because RFIs Are Vastly More Cost-Effective</u>

In addition to providing planners and operators with visibility through telemetering, remote fault indicators (RFIs) improve reliability by allowing operators to remotely direct troublemen closer to the location of the fault—this is a critical feature that allows for inexpensive

and all of the disparate supporting platforms and systems. Columns B and C present the costs, including the costs for intelligent switches, and benefits of respectively, the Assisted Switching and Automated functionalities of the GMS.

[104] Ex. SCE-02 V4 P1 WP, p. 171.

reliability improvement without the use of expensive switches and new circuit ties and circuit-tie upgrades.

RFIs are vastly cheaper than smart switches (i.e., $6,798 per unit versus $110,000 for RISs).[105] Indeed, five RFIs cost about a third as much as just one smart switch. Furthermore, the smart switch requires a circuit tie to provide switching-related functionality. The following is a table that compares the BCA of an RFI-only program (Column A) against the Assisted Switching and Automated Switching-supported Grid DA programs that SCE proposes (Columns B and C), which require an RIS and a circuit tie;[106] RFIs are excluded from Assisted Switching and Automated Switching in order to isolate the effect of RFIs on reliability and cost.

[105] Ex. TURN-04, p. 15. Reliability Driven DA BCA, 'Cost Summary' tab.

[106] Ex. TURN-04, p. 15. Within SCE's Reliability DA model, TURN uses the ratio of CMI reduction from switching to those from RFIs (i.e., 1.7376), as is used in the analysis included in TURN 48-8b, Attachment TURN-SCE-048_Q08_a-b_Reliability_Improvement_DA_2021 GRC, Tab 'No Meds' (Cell:AX22), to adjust the CMI reported in the Reliability DA BCA for the amount that is attributable to RFIs. Additionally, TURN used only the RFI costs (and zeroed out the rest).

BCA Comparison, RFIs-Only Assumption vs. SCE's Full Assisted and Automated Switching Approach[107]

225 Circuits Automated from 2021 - 2023; $ in millions

	A NetComm & Manual FLISR			B NetComm & C-FLISR			C FAN & C-FLISR		
	RFIs-Only			Assisted Switching			Automated Switching		
	Benefits	Costs	B/C	Benefits	Costs	B/C	Benefits	Costs	B/C
Option 1: All Load Break Switches (Mids and Ties)									
1:1	**$304**	**$16**	19.55	**$340**	**$72**	4.75	**$366**	**$72**	5.12
2:2	**$304**	**$16**	19.55	**$631**	**$157**	4.02	**$653**	**$157**	4.17
3:3	**$304**	**$16**	19.55	**$863**	**$257**	3.35	**$884**	**$257**	3.43
+1:+1	**$304**	**$16**	19.55	**$454**	**$92**	4.96	**$463**	**$92**	5.05
Option 2: Middle Midpoint Switch is Fault Interrupting (Other Mids and Ties are Load Break)									
1:1	**$304**	**$16**	19.55	**$341**	**$83**	4.08	**$367**	**$83**	4.40
2:2	**$304**	**$16**	19.55	**$636**	**$168**	3.79	**$672**	**$168**	4.01
3:3	**$304**	**$16**	19.55	**$872**	**$266**	3.28	**$915**	**$266**	3.44
Option 3: All Fault Interrupting Switches (Mids and Ties)									
1:1	**$304**	**$16**	19.55	**$341**	**$93**	3.68	**$367**	**$93**	3.96
2:2	**$304**	**$16**	19.55	**$636**	**$206**	3.08	**$674**	**$206**	3.26
3:3	**$304**	**$16**	19.55	**$872**	**$330**	2.64	**$1,053**	**$330**	3.19
+1:+1	**$304**	**$16**	19.55	**$460**	**$94**	4.89	**$475**	**$94**	5.04

Even more glaring than the RCS vs. RIS comparison discussed previously, the results of this analysis show that: 1) while the benefits of the RFI-only option (Column A) are generally lower than the benefits of the RIS plus circuit tie option, 2) the B/C ratio of Column A is much higher—by an average of about 5 times—owing to both the effectiveness and low cost of the RFI.

In its rebuttal, SCE claims that TURN overstates the benefits of its proposal and reproduced its own BCA with drastically lower values for TURN's recommended scenario.[108]

[107] Ex. TURN-04, p. 16. In this table, Column A (RFIs-Only) requires only RFIs as assumed in the Reliability DA BCA, while columns B and C reflect the BCA's assumptions for full deployment of the Grid Modernization proposal on 225 circuits, including intelligent switches, RFIs, circuit-tie upgrades, etc. The values include supporting O&M and are stated in terms of Present Value of Revenue Requirement (PVRR).

[108] Ex. SCE-13 V04 P1, p. 52.

At the same time, SCE concedes that its revised BCA for the RFI-only scenario does not account for any benefits associated with faster switching by operators.[109] Yet, this benefit of faster switching is well documented by other utilities, including by PG&E, who implemented the same line sensor technology and achieved an 18% reduction in customer minutes interrupted.[110] SCE further erroneously asserts, in its rebuttal, that SCE would need a GMS with Fault Location, Isolation, and Restoration ("FLISR") to realize any reliability benefits using RFIs.[111] Again, PG&E demonstrated that it was able to improve fault location by 10% or more without FLISR.[112] SCE also claims that ungrounded RFIs are unable to detect phase to ground faults sometimes.[113] Yet, SCE concedes that it has not conducted analysis to show the extent or what percentage of ground fault exhibit currents low enough to escape the detection of RFI.[114] These exclusion and errors make SCE's revised BCA inaccurate and of no decision-making value.

Thus, TURN recommends that SCE deploy more RFIs instead of RISs because RFIs are vastly more cost-effective.

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[109] Ex. SCE-51, DR TURN-SCE-103, Question 3.

[110] Ex. TURN-53, PG&E Advice Letter 4990-E Excerpt, Line Sensors Smart Grid Pilot Program Final Report, p. 3; Ex. TURN-54, Sentient Case Study for PG&E, p. 5. SCE asserts that PG&E's program was not continued after the pilot, but provides no evidence to support its assertion. TURN has doubts regarding SCE's assertion because it would be counter-intuitive and illogical for PG&E to submit an advice letter at the end of its pilot touting significant benefits and then discontinue the program.

[111] Ex. SCE-13 V04 P1, p. 51.

[112] Ex. TURN-53, PG&E Advice Letter 4990-E Excerpt, Fault Detection and Location Smart Grid Pilot Program Final Report, p. 22.

[113] Ex. SCE-13 V04 P1, p. 51; Ex. TURN-51, DR TURN-SCE-101, Question 3.

[114] 06 RT 754:21-755:12 (Gueorguiev/SCE).

SCE Should Also Limit the Number of Circuit Tie Upgrades (CTUs) that It Deploys

There are two types of circuit connection work that are generally involved with Grid DA,[115] -- new and upgraded circuit ties, which can include choker-tie upgrades and vault replacements.[116] Circuit ties are very expensive ways of achieving reliability, as TURN explained in the 2018 GRC. There, TURN demonstrated that it could cost $313 for every minute of CMI saved, or $1.6 billion for every minute of SAIDI saved[117] in the case of choker ties, which generally only restrict load transfer during peak times, meaning that the chance that they will be required during emergency conditions is low. Building new ties in order to achieve reliability is likewise very expensive.

TURN understands that the program comprises replacement vaults for certain circuit ties for which the existing vault is not sufficient to accommodate the new Grid DA switches. Regardless, TURN continues to maintain that circuit-tie work, whether for new ties or upgrades, including vault replacement at $369,413 per circuit tie,[118] is an expensive way to increase

[115] Ex. TURN-04, p. 13. Note that switching requires that two circuits be connected via conductor.

[116] Ex. TURN-04, p. 13. In the 2018 GRC, SCE stated, "SCE states: "The circuit choking condition occurs only during a peak load period. For this condition, it is assumed that the period in a year is: 1. Three months in a year, 2. Five working days in a week, 3. Six hours (12pm – 6pm) in a day." (Attachment S-55-7 Benefit of Replacing Circuit Tie Chokers to Supplemental Response to TURN-SCE-026-55 (2018 GRC)) . Additionally, "Chokers are a symptom of asymmetrical distribution system designs where smaller wire has been installed on mainline circuitry in locations originally serving small amounts of load/customers. Over many years, permanent system reconfigurations have taken place that have resulted in the creation of "chokers," or portions of wire serving more load than originally designed for or at risk of being overloaded during abnormal conditions such as emergency restoration or fault-related transfers. For new construction, SCE uses standard sizing for mainline circuitry to help avoid the creation of chokers at future reconfigurations." (2018 GRC, TURN-SCE-085-01.b)

[117] Ex. TURN-04, p. 13. 2018 GRC, Ex. TURN-03, p. 63:1-3.

[118] Ex. SCE-02 V4 P1 WP, p. 173.

reliability. SCE requests about $9.28 million per year, or a total of $27.32 million for 2021-2023,[119] to upgrade ties with vault replacements on 225 circuits.[120] In the last GRC, SCE requested $100 million for new ties and choker ties in order to automate 600 circuits, although in that case SCE was proposing a program with up to three circuit ties, rather than up to one proposed in this case.[121] TURN recommended against funding choker ties at all, and further recommended that the Commission authorize funding to deploy new circuit ties on only the 110 circuits, out of the 600 circuits proposed, that had no circuit ties at the time. The Commission adopted this approach.

Given that SCE is planning to vastly expand its Grid DA in the years to come, TURN recommends that the Commission continue to minimize expensive reliability projects. For simplicity, TURN recommends that the Commission authorize a forecast in this rate case that is commensurate with the ratio in the last GRC—i.e., 110 circuits out of the 600 planned. The result of this recommendation is a test-year forecast of about $1.815 million for circuit ties, a test year reduction of $7.578 million in capital.

TURN also recommends that if SCE proposes a larger program in the next rate case, the Commission should require SCE to identify each specific circuit tie that it intends to upgrade or install and demonstrate the cost-effectiveness of each, including reasonable alternatives.

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[119] Ex. TURN-04, p. 14. Reliability DA BCA, 'Option 3- +1&+1 Costs', scaled for SCE's forecast set forth in Figure II-25 on p. 104 of Ex. SCE-02V4P1.

[120] Ex. SCE-02 V4 P1 WP, p. 173.

[121] Ex. TURN-04, p. 14. 2018 GRC, TURN DR SCE reliability technology BCA ('3. Key Assumptions' tab) attached to TURN DR 26-55 in that proceeding.

10.2.4 IT Project Support

TURN is not addressing this issue in its opening brief but reserves the right to respond to other parties in TURN's reply brief.

10.2.5 Alleged Benefits of GM: The Commission Should be Cautious about the Alleged Benefits of Grid Modernization Investments and Provide Guidance to SCE for Future Rate Cases

<u>Any Benefits from a Future "Marketplace for DERs" Are Entirely Speculative</u>

SCE opines that it needs to be able to optimize DERs—dispatch them at the right locations and times with the most value to the grid—in order to be able to defer traditional grid investments.[122] SCE indicates that the E&P software tool investments in conjunction with the GMS would provide the real-time operational visibility and control needed to depend on DERs to provide distribution services on-demand.[123]

SCE has not attempted to quantify the value that DER may provide to the grid through a future marketplace.[124] TURN understands that there is a Distributed Resources Plan (DRP) framework that is intended to defer traditional wires- and substations-based investments into the future, but SCE has not offered evidence that has attempted to quantify or prioritize different levels of automation against engineering or smart inverter-enabled solutions that may assist in integrating traditional-grid-deferral DER solutions, and has not compared incremental capability of the Grid Modernization proposal to push traditional grid investments out into the future versus a scaled down version.

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[122] Ex. SCE-02 V4 P1, p. A-5:13-14.

[123] Id., p. 18.

[124] Ex. TURN-04, p. 6, citing TURN DR 22-17.

Perhaps even more importantly, there is absolutely no indication that even if all wholesale "values" of DERs (meaning the values they provide beyond individual customer bill reductions) including distribution value, ancillary service, and any energy and capacity value, are summed together, they would actually be worth more than the approximately $2 billion forecast for grid modernization. There is a huge underlying problem. The CAISO has developed real-time visibility and control over the transmission system. Through grid modernization SCE seeks similar control over the distribution system. However, given the relative sizes (i.e. mileage of distribution lines versus transmission), the number of actors (i.e. individual customers versus wholesale generators), it is simply unlikely that achieving the same control over the distribution system will be cost effective.

<u>Reliability Benefits of Grid Modernization Are Likely Overstated</u>

SCE expects its Grid Modernization proposal to improve reliability in the following ways:[125]

- Apply more switches to the targeted circuits: The more switches there are on a given circuit, the fewer customers will be affected when a fault occurs. This is true whether the switches are Remote Controlled Switches (RCSs) or Remote Intelligent Switches (RISs).
- Increase the speed at which faults can be located and isolated in the field: SCE plans to improve the field response with the addition of Remote Fault Indicators (RFIs), which help the grid operator remotely direct troublemen in further isolating the fault with additional manual switching.

[125] Ex. TURN-04, p. 18. An excerpt of TURN's testimony is included in Ex. TURN-04-Atch-1.

- Increase speed of the switching during a sustained outage: The faster the fault is isolated, the faster those customers whose service can be restored through switching will see their service restored. SCE plans to improve switching speed with (1) an integrated platform, which improves workflow; (2) assisted decision making through the GMS; and (3) automated improved communications, which will allow faster data transfer to and from the operations center, in addition to waiving human validation. The improved communications would be achieved through the FAN, WAN, and CSP.
- Increase the capacity of existing circuit ties so that circuits will not "choke" load.

The first two functionalities are achieved primarily with distribution automation, while the GMS and FAN are primarily intended to achieve the faster switching time.

The monetization of all reliability benefits (i.e. lower customer minutes of interruption) is based on the VOS study, which surveys customers to calculate a "dollar/minute of interruption" number. SCE's 2019 VOS study was based on surveys conducted in the first half of 2019.[126] While TURN accepts the need to use a VOS to monetize reliability benefits, there are several shortcomings in the VOS itself and in the way SCE uses the VOS results to perform the BCA for the discretionary grid modernization reliability project. These shortcomings include:

- Survey bias in the VOS itself.
- Lack of distinction in using VOS results between different customer classes. The VOS used in SCE's BCA analysis averages responses from different customer classes, and thus obscures the fact that residential customers value reliability by a factor of one

[126] Ex. SCE-02 V04 Pt01ChIIBkA WP, pp. 13- 109.

hundred to ten thousand times less than small business (SMB) or large commercial and industrial (C&I) customers.

- An overestimate of the benefits of the system-wide grid modernization program if other reliability investments are targeted to higher value circuits that contain more C&I customers.
- Lack of consideration of customer-owned generation and storage as reliability back-up methods that reduce the value of utility reliability to some C&I customers.

The VOS study has the potential for survey-response bias. Given that the survey was explicitly and exclusively about reliability and the cost of outages,[127] the potential bias comes from the fact that the very customers who are more likely to have a higher VOS are the ones who would more likely participate in the survey. This would lead to an upward bias in the measured values, a bias that Nexant does not adjust for. Nexant had a difficult time securing survey participants, obtaining far fewer responses per request than PG&E did in 2012, even after reaching out many times and expanding the size of the targeted customer count on an ad hoc basis just to obtain the desired sample size. Even having increased the targeted customer count, Nexant was only able to cajole enough responses to obtain about 50% of the desired sample size for both SMB and C&I customers.[128] As for Residential customers, it is unclear from the evidence what the response rate was.

[127] Ex. SCE-02 V4 P1 ChIIBkA, pp. 70-109.

[128] *Id.*, pp. 26, 29-30. SMB: 51.6% = 413 ÷ 800; C&I: 48.0% = 72 ÷ 150.

Another problem with the VOS is that the VOS is a blunt instrument. It takes the weighted average of the value that all customers ascribe to reliability (i.e., $2.63)[129] and applies it equally to each CMI. However, the value per CMI that C&I customers ascribe to service (i.e., $714), is orders of magnitude larger than the value ascribed by the Residential class (i.e., $0.07) or even the SMB class (i.e., $21).[130]

The following table presents a comparison of the BCA (both Net Present Value (NPV) and BCR) results assuming an all-Residential VOS as compared to the weighted-average VOS:

Comparison of the NPV and BCR for a Weighted Average Assumption and Residential-Only Assumption[131]

VOS Assumption	Present Values ($ in millions)					Benefit/Cost Ratios			
	GMS					GMS			
	Benefits								
	Assisted Decision Making	Automated Decision Making	Avoided DER Impairment	Costs	NPV	Assisted Decision Making	Automated Decision Making	Avoided DER Impairment	Total
Weighted Average VOS ($2.63/CMI)	$887.0	$ -	$ 349.5	$265.0	$971.5	3.3	0.0	1.3	4.7
Residential-only VOS ($0.07/CMI)	$23.6	$ -	$ 9.3	$265.0	$ (232.13)	0.1	0.0	0.0	0.1

The table shows that applying the Residential VOS reduces the NPV of the GMS component from a positive $971.5 million to a negative $232 million, and reduces the Benefit/Cost ratio from 4.7 to 0.1. An expensive, centralized and systemic reliability project, such as the GMS, looks much less appealing from the Residential ratepayer's perspective as shown in the table, which does not even include the $500-$600 million cost of the FAN system.

129 *Id.*, p. 59 (Table 8-6 of Nexant VOS study).

130 *Id.*

131 Ex. TURN-04, p. 21. The Residential VOS calculation uses GMS BCA_2021GRC_REVISED model, which SCE attached to its response to TURN DR 6-11.i (revised).

It may be more VOS-effective to target the installation of more switches to areas that benefit more from increased reliability, than it is to install an expensive, systemic solution.[132]

Finally, the BCA as applied using the average VOS from across all customer classes and sizes for systemic reliability proposal, such as GMS and FAN, has the potential to overstate the benefits insofar as the company might already focus reliability efforts such as historical substation and line SCADA or infrastructure replacement and/or reinforcement on sections of the grid that have higher than average densities of large customers. This is because SCE bases the reliability improvement that it expects with the Grid Modernization program by modeling the CMI reduction of the Grid Modernization proposal using actual historical outage data. If the estimated benefits that are calculated this way are spread evenly across a grid, and if automation, replacements and reinforcements are focused on circuits with large customers, the BCA will be biased on the high side.[133]

Furthermore, this bias is exacerbated given that Nexant does not include whether the customer has backup power to mitigate outages in the damage function that supports the VOS for any of the customer-class/size designations. It is reasonable to expect that large customers with backup power have self-insured against outages and that such measures are more common with

[132] TURN is not endorsing through this statement any particular targeted-reliability program or even the concept of targeted reliability at this time—TURN is providing these values and observations simply as points of reference for the Commission to use when contemplating the merits of SCE's Grid Modernization program. TURN would require further study and possible revenue allocation carveouts for large customers in Phase II to support a targeted solution. Such a solution is more akin to the installation of "special facilities" to support large individual customers.

[133] TURN understands that some outages, such as cars knocking perfectly fine poles over are beyond the utility's control and would not be impact the BCA in the same way as a program that focuses infrastructure replacement and reinforcement on areas of high large-customer density.

large than small and medium customers. Such customers, while clearly valuing reliability highly, would likely value any reliability improvements provided by the utility less than other customers, given the insurance policy they've already invested in.

In its rebuttal, SCE claims that to the extent a customer has backup generator, uninterruptible power supply or other devices that would help to mitigate a power interruption, the backup generator should be reflected in the customer responses.[134] Yet, it did not provide a citation to support this assertion, nor was it able to provide one during cross examination. Similarly, SCE asserts that "[s]ince the Nexant survey properly accounts for customer-owned backup power and energy storage, there should be no upward bias in the VOS results or the BCAs that use the VOS results."[135] Again, SCE did not provide a citation to support its assertion that if a customer provides a cost to run back-up generation equipment as a result of the survey, Nexant would remove or adjust the value from the VOS study, nor was SCE able to provide support during cross examination. After evidentiary hearings, SCE provided an exhibit that contains multiple layers of inferences in an attempt to demonstrate its assertion,[136] but the exhibit was unable to show conclusively that the VOS does not contain upward bias.

Hence, the Commission should be mindful that the reliability benefits of Grid Modernization are likely overstated.

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[134] Ex. SCE-13 V04 P1, p. 45.

[135] Ex. SCE-13 V04 P1, p. 45.

[136] Ex. SCE-101, pp. 1-2.

<u>The Commission Should Be Cautious About Grid Modernization and Require a More Robust Showing in Future Rate Cases</u>

As discussed above, TURN does not oppose the replacement of legacy equipment in this case, but we have serious concerns that the primary benefit of the grid modernization solution that SCE has proposed—which focuses on the reduction in system SAIDI due to faster switching times—may be overvalued due to inaccurate estimates of switching time benefits, and the inherent flaws of using aggregate value of service survey data. However, TURN recommends that the Commission provide guidance to SCE in this case regarding the type of showing that must be made in the future to justify the additional $1.4 billion estimated by SCE for 2024-2028 to complete grid modernization. That amount is primarily for additional distribution automation and to complete the FAN installation. Most importantly, SCE should be encouraged to invest in RFIs over more switches and circuit ties in order to improve reliability.

TURN opposed the addition of multi-switch and -circuit-tie solutions in the last rate case, based on the declining marginal benefits of additional switches and circuit ties on a circuit. SCE's analysis in this case support our concern. If SCE does return with a proposal for additional distribution automation in future cases, the Commission should make clear that SCE must:

- Show that the incremental benefits of adding more switches and ties to a circuit are greater than the incremental costs of the investments;
- Compare the costs and benefits of using remote intelligent switches to improve reliability against costs and benefits of using remote controlled switches; and

- Identify each specific circuit tie that it intends to upgrade or install, rather than use simple average costs and unit counts, and demonstrate the cost-effectiveness of each against reasonable alternatives.

10.3 Energy Storage

11. LOAD GROWTH, TRANSMISSION PROJECTS, AND ENGINEERING

11.1 Overview

11.2 Load Growth

11.3 Engineering

11.3.1 Load Side Support

11.4 Other Issues

12. NEW SERVICE CONNECTIONS AND CUSTOMER REQUESTED SYSTEM MODIFICATIONS

12.1 New Meter Connections

SCE forecasts new meter connections, which then form the basis for its forecast of new service connection capital expenditures.[137] Residential and commercial new service connections comprise the largest area of non-wildfire capital spending proposed by SCE in this GRC.[138] SCE proposes $1.417 billion in capital expenditures from 2019-2023 for new service connections, including $284 million in the test year.[139]

TURN recommends a lower forecast of residential and commercial new meter connections than SCE for reasons unrelated to the COVID-19 pandemic, as explained below. This adjustment results in a reduction in the forecast for new service connection capital

[137] Ex. SCE-02V4P3, p. 4.

[138] Ex. TURN-07, p. 10.

[139] Ex. SCE-02V4P3, p. 2.

expenditures. TURN does not oppose SCE's methodology for translating the gross meter set forecast to the forecast of new service connection work activities.[140]

In rebuttal testimony, SCE accepted TURN's forecast for commercial new meter connections and pledged to investigate an alternative forecast methodology, as proposed by TURN.[141] SCE agreed with TURN that "residential meter sets no longer appear to have robust explanatory power in forecasting commercial/industrial meter sets, as they have in earlier periods," and relying on residential meter sets "likely over forecasts commercial/industrial meter set additions."[142] As this issue is no longer in dispute, TURN recommends that the Commission adopt TURN's forecast for commercial new service conditions and the associated reductions to SCE's capital expenditures.[143]

TURN's forecasts of residential and commercial new meter connections and associated capital expenditures, as compared to SCE's original forecasts, are as follows.[144]

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[140] *See* Ex. SCE-02V4P3, pp. 4-5.

[141] Ex. SCE-18V1, pp. 39, 40-41.

[142] Ex. SCE-18V1, p. 39.

[143] *See* Ex. SCE-54, Joint Comparison Exhibit, p. 69.

[144] *See* Ex. SCE-57, Joint Comparison Exhibit, Issue TURN-30, p. 137 (Residential) and Issue SCE-001, p. 69 (Commercial). TURN's testimony presents capital expenditures in 2018 Constant $. *See* Ex. TURN-02, p. 47 (Tables 12 and 13). SCE converted TURN's forecast to Nominal $ in Rebuttal Testimony and the Comparison Exhibit. TURN uses SCE's figures here to avoid confusion but has not verified SCE's conversion calculation.

Table 12-1

	Residential Meters		
	SCE	TURN	TURN-SCE
2021	36,443	30,560	(5,883)
2022	38,545	30,107	(8,438)
2023	40,653	31,495	(9,158)
TOTAL	115,641	92,162	(23,479)

Table 12-2

	Residential New Service Connections - Capital Expenditures (Nominal - $000)		
	SCE	TURN	TURN-SCE
2021	$ 149,787	$ 118,520	$ (31,267)
2022	$ 162,737	$ 125,937	$ (36,800)
2023	$ 166,412	$ 157,768	$ (8,644)
TOTAL	$ 478,936	$ 402,225	$ (76,711)

Table 12-3

	Commercial Meters		
	SCE	TURN	TURN-SCE
2021	5,433	4,751	(682)
2022	5,440	4,751	(689)
2023	5,472	4,751	(721)
TOTAL	16,345	14,253	(2,092)

Table 12-4

	Commercial New Service Connections - Capital Expenditures (Nominal - $000)		
	SCE (original)	TURN	TURN-SCE
2021	$ 101,244	$ 88,533	$ (12,711)
2022	$ 104,300	$ 91,094	$ (13,206)
2023	$ 107,941	$ 93,714	$ (14,227)
TOTAL	$ 313,485	$ 273,341	$ (40,144)

The Commission should adopt TURN's forecasts for the reasons provided in TURN's testimony and below. In the sections that follow, TURN focuses on residential meters because that is the only issue in dispute between TURN and SCE.

12.1.1 SCE Has Consistently Over-Forecast New Meter Sets, Despite Changes to the Explanatory Variable Inputs Used In Its Regression Model.

SCE used different explanatory variables in forecast model for new meters sets in each of the last four GRCs (including this GRC).[145] For the 2012 GRC, SCE used Global Insight's Base Case forecast of building permits as the primary explanatory variable to forecast new meter sets. For the 2015 GRC, SCE switched from building permits to housing starts and used the average of Global Insight's and Moody's Base Case housing starts forecasts. For the 2018 GRC, SCE dropped IHS Global Insight's forecast because it was "more optimistic" than Moody's, and instead used only Moody's Base Case housing starts forecast. Despite these changes, SCE has consistently over-forecast residential new meters, as shown in the following table.[146]

[145] Ex. SCE-28, TURN-SCE-084, Response to Question 6.

[146] SCE forecasts from Ex. TURN-02-Atch 1, SCE Meter Set Forecasts from 2012, 2015, and 2018 GRCs; 2012-2018 Recorded from Ex. SCE-02V4P3, Table II-2; 2019 Recorded from Ex. TURN-02-Atch 1, TURN-SCE-015, Q2.

Table 12-5

	Residential Meter Sets		Commercial Meter Sets		
Year	SCE Forecast	Recorded	SCE Forecast	Recorded	Forecast Source
2012	38,591	17,692	7,443	4,865	2012 GRC
2013	46,853	21,840	8,627	5,252	2012 GRC
2014	49,732	24,339	9,869	5,231	2012 GRC
2015	51,238	26,423	8,607	4,711	2015 GRC
2016	56,320	32,231	10,698	5,217	2015 GRC
2017	55,939	34,489	11,897	4,767	2015 GRC
2018	41,702	34,759	6,825	4,622	2018 GRC
2019	43,438	34,685	7,665	4,438	2018 GRC

SCE's forecasts improved as it revised its forecast methodology, at least for residential meter sets. The following table shows SCE's forecasts of new meter sets as a percentage of recorded values for each year from 2012-2019, using data from Table 12-5.

Table 12-6

	Residential Meter Sets	Commercial Meter Sets
Year	SCE Forecast / Recorded (%)	SCE Forecast / Recorded (%)
2012	218%	153%
2013	215%	164%
2014	204%	189%
2015	194%	183%
2016	175%	205%
2017	162%	250%
2018	120%	148%
2019	125%	173%

For the 2021 GRC, SCE has again revised its forecast methodology, but still relies primarily on Moody's forecast of housing starts to forecast new meter sets. As in the 2018 GRC, SCE used Moody's Base Case housing starts forecast, which was less optimistic than the forecast from IHS, but SCE additionally "made a downward adjustment to its residential new meter forecast by choosing an alternative regression model specification."[147] SCE did not reduce the number of forecast housing starts, but changed some regression model specifications, resulting in a lower new meter set forecast. Specifically, SCE removed the "SCEMULTISHARE" variable for its 2021 GRC forecast and also extended the lag from 6 months to 15 months for the "SCESTRT" variable.[148] SCE explains that it made these changes "to adjust for Moody's optimistic Base Case housing starts forecast."[149] The combination of these two adjustments to SCE's meter set forecast model reduced the resulting meter set forecast by 8.6% in 2021, 10.2% in 2022, and 4.1% in 2023 relative to SCE's original forecast.[150] But even with this reduction, SCE still projects annual growth in the number of new meter connections each year from 2019-2023.[151]

There is no reason to believe that SCE's downward adjustments go far enough. SCE's forecast in the 2018 GRC using Moody's Base Case housing starts forecast was 20% too high for 2018 and 25% too high for 2019.

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[147] Ex. SCE-28, TURN-SCE-084, Response to Question 6.

[148] Ex. TURN-24, TURN-SCE-102, Response to Question 1.

[149] Ex. SCE-18V1, p. 40.

[150] Ex. TURN-24, TURN-SCE-102, Response to Question 1.

[151] Ex. TURN-02, p. 48, Figure 9.

12.1.2 TURN's Residential Forecast in the 2018 GRC, Which Did Not Rely on Third Party Vendor Housing Start Forecasts, Was More Accurate Than SCE's.

Like SCE, TURN has evolved its forecast methodology in response to historic data. TURN used the same approach in the 2012 and 2015 GRCs, which included updating SCE's forecast with the latest available recorded data and most recent forecasts from the third party vendors used by SCE, as well as adjustments to SCE's model.[152] For the 2018 GRC, TURN moved away from vendor forecasts of housing starts in an attempt to improve forecast accuracy. TURN's methodology adjusted the housing start input in SCE's regression model to reflect the average growth rate in actual housing starts from 2014-2016, the most recent three years of recorded data when TURN prepared its testimony.[153]

While SCE is correct in suggesting that its forecasts are improving in accuracy, TURN's forecast in the 2018 GRC was still more accurate than SCE's, albeit still too high.[154] The following table compares the accuracy of TURN's forecast of residential new meter sets in the 2018 GRC to SCE's.[155]

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[152] See D.12-11-051, p. 172 (summarizing TURN's methodology); D.15-11-021, p. 378 (summarizing TURN's methodology).

[153] See D.19-05-020, p. 274.

[154] Ex. SCE-18V1, p. 40.

[155] See D.19-05-020, p. 278 (adopting TURN's forecasts for new residential meters); Ex. SCE-02V4P3, Table II-2 (2018 recorded); Ex. TURN-02-Atch 1, TURN-SCE-015, Q2 (2019 recorded).

Table 12-7

	Residential Meter Sets - 2018 GRC Forecast Accuracy				
Year	**Recorded Meter Sets**	**TURN Forecast**	**TURN Forecast / Recorded (%)**	**SCE Forecast**	**SCE Forecast / Recorded (%)**
2018	34,759	36,388	105%	41,702	120%
2019	34,685	37,955	109%	43,438	125%
2020	N/A	37,729	N/A	42,801	N/A

12.1.3 TURN's Forecast in This GRC Reasonably Incorporates Lessons Learned From Past GRCs and Recent History.

In preparing its forecast in this GRC, TURN evaluated the accuracy of TURN's previous forecast methodologies in addition to SCE's. TURN's forecast in the 2018 GRC, which relied on historical housing starts, not third party vendor forecasts, was the most accurate forecast in the past three GRCs.[156] Yet is was still high. For the 2021 GRC, TURN accepted SCE's calculated coefficients from its regression model but adjusted the number of forecast housing starts that form the basis of the residential meter forecast. Instead of Moody's forecast of housing starts, TURN used a five-year average of actual housing starts from 2015-2019 and assumed this same level of housing starts for 2021, 2022, and 2023.[157]

TURN used this methodology for two reasons. First, TURN sought to correct for SCE's history of over-forecasting new meter sets when relying on third party vendor housing start

[156] See Ex. TURN-02, p. 52, Figure 12 (comparing recorded new meters to SCE's forecasts and Commission authorized new meters). The Commission adopted TURN's forecasts of residential and small commercial new meters in the 2012, 2015, and 2018 GRCs. D.12-11-051, pp. 173-174; D.15-11-021, pp. 378-379; D.19-05-020, p. 278.

[157] Ex. TURN-02, p. 55.

forecasts as a primary model input.[158] Second, TURN used a historic average because housing starts and new meter connections have begun to level off.[159] From 2013 until 2019, the number of annual housing starts moved up and down from a low of approximately 37,500 in 2018 to a high of approximately 50,000 in 2017. As a result of this fluctuation, the results are similar when one uses the 7-year 2013-2019 average, 6-year 2014-2019 average, 5-year 2015-2019 average (used by TURN), 4-year 2016-2019 average, and 3-year 2017-2019 average. The two-year 2018-2019 average is lower than the five-year 2015-2019 average recommended by TURN. The following table presents this information, which illustrates the "leveling off" of housing starts following the housing industry recovery from the Great Recession.[160]

[158] Ex. TURN-02-E, p. 55.

[159] Ex. TURN-02-E, p. 55.

[160] See Ex. SCE-28, TURN-SCE-084, Q5 (recorded annual housing starts, 2005-2019).

Table 12-8

Year	Actual Housing Starts	Average 2005-2019	Average 2013-2019	Average 2014-2019	Average 2015-2019	Average 2016-2019	Average 2017-2019	Average 2018-2019
2005	81,215	81,215						
2006	60,671	60,671						
2007	33,939	33,939						
2008	17,738	17,738						
2009	16,030	16,030						
2010	14,047	14,047						
2011	19,286	19,286						
2012	28,316	28,316						
2013	38,826	38,826	38,826					
2014	47,350	47,350	47,350	47,350				
2015	38,117	38,117	38,117	38,117	38,117			
2016	46,397	46,397	46,397	46,397	46,397	46,397		
2017	49,993	49,993	49,993	49,993	49,993	49,993	49,993	
2018	37,507	37,507	37,507	37,507	37,507	37,507	37,507	37,507
2019	43,379	43,379	43,379	43,379	43,379	43,379	43,379	43,379
Averages		**38,187**	**43,081**	**43,790**	**43,079**	**44,319**	**43,626**	**40,443**

* TURN used the shaded average in its forecast.

In contrast, SCE assumes growth in the number of housing starts from 2018 through 2021, before a slight decrease in 2022 and 2023.[161] SCE's housing starts forecast for 2018 and 2019 in this GRC significantly exceed actual starts in both years.[162] SCE's housing starts forecasts for 2020-2023, years that impact its forecast of new meters, are higher than seen in any

[161] Ex. SCE-07V1A2, p. 70, Figure VI-5 (Housing Starts in the SCE Service Area, 2009-2008 Actual, 2019-2023 Forecast).

[162] Compare Table 12-8 to Ex. SCE-07V1A2, p. 70, Figure VI-5. *See also* TURN-02C, p. 56, Figure 16 CONFIDENTIAL (showing, among other things, SCE's specific housing starts forecasts for 2018 and 2019 in this GRC compared to recorded starts).

year since 2006.[163] SCE's optimism – tempered slightly by its model adjustments – is nonetheless driven by Moody's optimism. Both have proven overblown in the past.

It is also important to understand that TURN did not adjust its forecast of new meter sets to account for impacts of the COVID-19 pandemic, which could put downward pressure on new meter sets in this GRC cycle.[164] As Mr. Borden explained in response to a data request from Small Business Utility Advocates (SBUA), "TURN is not currently aware of a reliable housing start forecast for California or SCE's service territory that incorporates the effects of COVID-19 on housing starts or new meter connections for the 2021-2023 time period."[165]

Given all of these factors, the Commission should find that TURN offers a reasonable alternative to SCE's overly optimistic forecast of new meter connections in this GRC cycle.

12.1.4 SCE Ignores the Fact That the Commission Adopted a Forecast of New Meter Sets in the 2018 GRC That Was Based Neither on Economic Vendor Forecasts Nor Demographic Drivers of Housing Starts.

SCE suggests that TURN's methodology should be rejected because it does not rely on "the well-established methodology of forecasting new meter connections on a forward-looking basis based on expert input on housing and other macroeconomic trends."[166] SCE claims that TURN's approach "is both contrary to typical housing forecasting methods and to GRC precedent" and "would lead to inaccurate results."[167] Finally, SCE asserts, "If the Commission

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[163] Ex. SCE-07V1A2, p. 70, Figure VI-5; Ex. SCE-28, TURN-SCE-084, Q5 (recorded annual housing starts, 2005-2019).

[164] Ex. TURN-02, p. 48, fn. 151.

[165] Ex. SBUA-03, TURN Response to SBUA Data Request 1, Question 1.

[166] Ex. SCE-18V1, p. 33.

[167] Ex. SCE-18V1, p. 34.

desires to impose a forecast that is based solely on hindsight they should apply this significant change in forecasting approach prospectively."[168]

These arguments are familiar, as SCE raised similar objections to TURN's forecast in the 2018 GRC. As the Commission explained in D.19-05-020, SCE "faults TURN for offering what SCE considers 'an arbitrary projection with no economic or demographic foundation.'"[169] SCE also warned – incorrectly it turned out – that TURN's housing starts forecast "will lead to a significant under-forecast of residential meters."[170] In fact, TURN's forecasts of new meter connections were slightly high for 2018 and 2019, and more accurate than SCE's, as shown in Table 12-7 above.

In D.19-05-020, the Commission found SCE's objections unpersuasive:

> [W]e find TURN's approach to forecasting new meters, as well as its analysis of prior GRC outcomes, to be carefully conceived and executed, and then explained clearly and transparently. TURN demonstrated that SCE has consistently over-forecasted new meters in recent GRCs. For that reason, we are reluctant to adopt SCE's forecast in this proceeding. Instead, we adopt the results of TURN's analysis as the forecast of SCE's new meters for residential and commercial accounts.[171]

Given the outcome in SCE's 2018 GRC, the Commission must reject SCE's claim that TURN's forecast methodology is "contrary to GRC precedent" and otherwise suspect because it does not rely on Moody's (or another third party vendor's) forecast of housing starts based on economic and demographic trends. The Commission has already endorsed a forecast methodology with, in SCE's words, "no economic or demographic foundation" to project future

[168] Ex. SCE-18V1, p. 35.

[169] D.19-05-020, p. 276.

[170] D.19-05-020, p. 276.

[171] D.19-05-020, p. 277.

housing starts, rather than the forecast of a third party vendor. That forecast methodology proved more accurate than SCE's in the 2018 GRC.

12.1.5 SCE's Evaluation of the "Accuracy" of TURN's Forecast Methodology Is Inapt.

SCE criticizes TURN's forecast methodology because it "would have resulted in large forecast errors over the recent years 2013-2019 and have led to significant under-prediction of new housing starts."[172] SCE explains that it tested the ability of TURN's forecast methodology, a five-year historical average, to predict actual housing starts in each year from 2013 to 2019. SCE calculated forecasts using the equivalent of TURN's methodology for this GRC, where the five-year series ends two years before the forecast year, akin to stopping at 2019 for the 2021 forecast (what SCE calls "TURN's Proposed Forecast with Additional Data"), and also using the five-year series that ends three years before the forecast year, akin to stopping at 2018 for the 2021 forecast (what SCE calls "TURN's Proposed Forecast without Additional Data").[173] SCE reports that TURN's method would have undercounted new housing starts 70% of the time using the "with Additional Data" historical series and 100% of the time using the "without Additional Data" historical series.[174] SCE then concludes that there is "no reason to believe" that TURN's methodology in this GRC "would be a principled, long-term methodology going forward."[175]

The Commission should disregard SCE's analysis and conclusions for three reasons. First, TURN prepared its forecast for this GRC in light of current circumstances (pre-COVID-19

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[172] Ex. SCE-18V1, pp. 33-34.

[173] Ex. SCE-18V1, pp. 37-38 and Figure IV-2; Ex. SCE-28, TURN-SCE-084, Q5 (SCE's Excel calculations underlying Figure IV-2).

[174] Ex. SCE-18V1, pp. 37-38.

[175] Ex. SCE-18V1, p. 38.

impacts), using a methodology that TURN believes makes sense for the years in question in this GRC cycle, 2021-2023. TURN did not propose this methodology for prior GRCs, as discussed above. Nor is TURN proposing a "long-term methodology" to be applied automatically to future GRCs. Rather, in keeping with the Commission's long-established guidance on GRC forecasting, TURN has tailored our forecast in this proceeding to the circumstances presented here, which are different than past circumstances and may also be different than future circumstances. As the Commission explained in D.06-05-016, issued in the SCE 2006 GRC, "Depending on circumstances, one [forecasting] method may be more appropriate than others. Under other circumstances, two or more methods may be equally appropriate."[176]

Second, it is unreasonable to presume, as SCE apparently does, that TURN would have proposed a forecast methodology in the 2012, 2015, or 2018 GRCs that used a five-year historical series to forecast future housing starts that included the impacts of the Great Recession. The recession and economic recovery following the 2007 Great Recession is generally thought to have lasted into 2013, with some variation depending on the metric used to measure the length of impacts.[177] As Table 12-8 shows, housing starts fell precipitously in 2007 through 2010 and stayed depressed relative to more recent activity until 2013. In the 2018 GRC, when TURN first proposed the use of historical housing starts, TURN used 2014-2016 recorded starts, not years before then. This approach kept the recessionary impacts out of the forecast. Even in the 2012 GRC, litigated when the effects of the Great Recession were still very present, TURN's forecast assumed customer growth in the forecast period while also taking into account the "lingering

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[176] D.06-05-016, p. 10.

[177] Ex. TURN-24, UCLA Anderson Forecast, June 2020, pp. 28-Nation to 30-Nation, Figures 1-4.

economic effects of the recession in SCE's territory."[178] But TURN did not suggest that the housing starts in 2007-2010 would be predictive.

Nonetheless, SCE's "accuracy test" includes recorded housing starts from some or all years between 2007-2012 in the historical averages SCE calculated for each year.[179] SCE's calculation for 2013 using the "with Additional Data" method used 2007-2011 data, while 2013 "without Additional data" used 2006-2010 data. By 2018 and 2019, the historical series used by SCE was much less impacted by the Great Recession. The 2018 "forecast" calculated by SCE used 2012-2016 data in the "with Additional Data" method, while the 2019 forecast in the "without Additional Data" method used these same years, 2012-2016.

Third, SCE's test tends to affirm the reasonableness of TURN's methodology once the majority of years reflecting the impacts of the Great Recession drop out from the historical averages. At that point, accuracy increases significantly. Using the "with Additional Data" method – the one TURN used in this GRC – the forecast SCE calculated was 6% high in 2018 (using 2012-2016 data) and 2% high in 2019 (using 2013-2017 data). Likewise, the "without Additional Data" results were 8% low in both 2018 (using 2011-2015 data) and 2019 (using 2012-2016 data).[180] These results are much better than SCE's housing starts forecast in the 2018 GRC, which was 41% higher than recorded in 2018 and 19% higher than recorded in 2019.[181]

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[178] D.12-11-051, pp. 172-173.

[179] Ex. SCE-28, TURN-SCE-084, Q5 (SCE's Excel calculations underlying Figure IV-2).

[180] Ex. SCE-28, TURN-SCE-084, Q5 (SCE's Excel calculations underlying Figure IV-2).

[181] Ex. TURN-02-E, Figure 15 (Housing Start Recorded vs. Forecast, 2015-2019). SCE forecast 52,846 housing starts in 2018 in the 2018 GRC, compared to 37,507 actual starts, and 51,751 housing starts in 2019, compared to 43,379 actual starts.

The 2018 and 2019 forecasts resulting from SCE's "test" of TURN's methodology are also more accurate than SCE's housing starts forecasts for 2018 and 2019 *in this GRC*.[182]

12.1.6 The Commission Should Recognize that COVID-19 Could Negatively Impact the Number of New Meter Connections in this GRC Period, Despite SCE's Recalcitrance.

New meter connections follow housing starts, with typical lags of up to 12 months.[183] As a result, housing starts this year will impact new meter connections this year and in 2021. Housing starts next year, 2021, can impact new meter connections that year and into 2022. Similarly, housing starts in 2022 can impact new meter connections that year and into 2023. The impact of COVID-19 on housing starts this year and in 2021-2022 is presently unknown, as are the impacts of COVID-19 on new meter connections. TURN does not purport to know when the economy will rebound or when housing construction and associated customer growth will return to levels anticipated before COVID-19.[184] However, we recognize that others predict a slow economic recovery for California and the rest of the United States.[185]

SCE insists on downplaying the possibility that COVID-19 may put a damper on new meter connections. In the SCE 2009 GRC, SCE updated its forecasts for customer growth and

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[182] Ex. SCE-07V1A2, p. 70, Figure VI-5 (Housing Starts in the SCE Service Area, with 2018 a blend of actual and forecast, and 2019-2023 forecast); Ex. SCE-28, TURN-SCE-084, Q5 (recorded annual housing starts, 2005-2019). As shown in SCE's Figure IV-5, SCE forecast approximately 50,000 housing starts in 2018 and 2019 in this GRC, compared to 37,507 actual starts in 2018 and 43,379 actual starts in 2019. SCE's specific housing starts forecasts for 2018 and 2019 are CONFIDENTIAL and provided in Ex. TURN-02C, p. 56, Figure 16 CONFIDENTIAL.

[183] Ex. SCE-07V1A2, p. 77. One of the regression model specification adjustments SCE made in this GRC was to extend the lag term from 6 months to 15 months. Ex. TURN-24, TURN-SCE-102, Question 1.

[184] See, also, Section 4.3 above, discussing COVID-19 issues generally, and Section 41 below, discussing COVID-19 issues in the context of Post-Test Year Ratemaking.

[185] Ex. TURN-24, UCLA Anderson Forecast, June 2020, p. Nation-13; pp. California-83, -86.

new meter sets in its May 2008 "Current Outlook" in response to the Great Recession, which commenced after SCE filed its GRC application. TURN asked SCE whether it prepared a similar "Current Outlook" forecast in this GRC to account for the effects of COVID-19 in California.[186] SCE responded that it had not because the "Great Recession was triggered by a housing bubble which is different from the current recession driven by COVID-19."[187] SCE also explained that it "considers long-term impacts of economic and demographic trends on housing starts when forecasting new meter sets, not short-term impacts," and indicated that it is too early to tell if the short-term uncertainty introduced by the pandemic will have long-term impacts on housing starts.[188]

TURN does not disagree that it is too early to predict the *long-term* impacts of COVID-19 on housing starts in SCE's service territory. However, *short-term* housing start activity will impact the number of new meter connections in 2021 and potentially also in 2022-2023. To the extent that housing starts were delayed earlier this year, or construction takes longer than usual because of public health / labor compliance obligations or supply chain delays, or contractors cancel projects planned for this year because of economic uncertainty, it is reasonable to assume that these COVID-19 related impacts will impact new meter connections in the 2021 GRC cycle. These possible *short-term* impacts can occur, irrespective of any *long-term* impacts of COVID-19 on the economic and demographic trends that have an impact on housing starts.

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[186] Ex. SCE-28, TURN-SCE-084, Question 3.

[187] Ex. SCE-28, TURN-SCE-084, Question 3. *See also* Ex. SBUA-06, Data Request SBUA-SCE-006, Question 5 ("At this time, SCE has not developed a new meter account forecast that incorporates any impact from COVID-19.").

[188] Ex. SCE-28, TURN-SCE-084, Question 3.

As TURN explained in its testimony, TURN did not adjust its forecast downward to anticipate the impacts of COVID-19 on new meter connections, nor do the historical averages used by TURN incorporate any effect of the pandemic.[189] As a result, TURN recognizes that its forecast may be higher than the future will show was warranted. The Commission should recognize this possibility in considering whether SCE's forecast, which assumes more housing starts this year and in 2021-2023 than recorded since 2006, is reasonable.[190]

12.1.7 The Commission Should Find that SCE Has Not Met Its Burden To Demonstrate The Reasonableness of Its Forecast, and Adopt TURN's Instead.

SCE has the burden to prove that its forecast is reasonable. The Commission should find that SCE has not met that burden. While SCE has refined its forecast methodologies across GRCs to improve accuracy, SCE has continued to rely heavily on third party vendors and has significantly over-forecast housing starts and residential new meter connections. Even with its forecast methodology in this GRC, which is more conservative than in the 2018 GRC, SCE's forecasts of 2018 and 2019 housing starts substantially exceeded actual housing starts. There is no reason to expect that its forecasts for 2021-2023 will be anything other than too high. In contrast, TURN has provided a well-reasoned, transparent alternative to SCE's forecast that warrants the Commission's adoption.

12.2 Rule 20A Conversions: SCE Agrees that Its Forecast Should Be Reduced by $31.1 Million for This GRC Cycle

[189] Ex. TURN-02, pp. 48, fn. 151; pp. 50-51, 60.

[190] Ex. SCE-07V1A2, p. 70, Figure VI-5; Ex. SCE-28, TURN-SCE-084, Q5 (recorded annual housing starts, 2005-2019).

SCE requests $16.002 million per year for Rule 20A Conversions.[191] To develop its 2021 forecast of $16.002 million, SCE uses a five-year average of recorded expenditures. While TURN agrees with the forecast methodology, SCE's forecast must be adjusted by the balance in the Rule 20A balancing account. Thus, TURN recommends a reduction of $31.1 million for this GRC cycle because there is a balance of $31.1 million in the Rule 20A Balancing Account, and SCE is unlikely to spend more than $16.002 million a year, given that it only spent an average of $13.865 million per year during the last GRC cycle. In its rebuttal, SCE accepted TURN's recommendation and agreed to reduce its forecast to account for the balance in the Rule 20A balancing account.[192]

Furthermore, TURN also supports SCE's proposal to maintain the one-way balancing account for Rule 20A.[193]

13. POLES

13.1 Overview

13.2 Pole Replacement

13.3 Pole Credits

13.4 Other Issues

14. VEGETATION MANAGEMENT

14.1 Overview

[191] Ex. SCE-02 V04 P3, p. 52.

[192] Ex. SCE-13 V04 P3, pp. 14-15.

[193] Ex. SCE-07 V01A, p. 40.

SCE's direct and rebuttal testimony, after several revisions, arrived at a total 2021 O&M forecast of $211.08 million, broken down as follows among four programs:[194]

Program	2021 Forecast (2018 Constant $)
Distribution Routine Vegetation Management	$107,012,000
Transmission Routine Vegetation Management	$12,760,000
Dead, Dying and Diseased Tree Removal	$35,120,000
Hazard Tree Management Program (aka Wildfire Vegetation Management)	$56,188,000
Total	**$211,080,000**

TURN's testimony did not take a position on SCE's forecast for the first three programs listed above, and TURN continues to have no position on those forecasts. TURN focused its analysis on the program and forecast with which it has the greatest concern, the Hazard Tree Management Program (HTMP). Accordingly, the remainder of this section of the brief will be limited to addressing SCE's forecast for HTMP.

In Update testimony, SCE sought to increase its forecasts for all four Vegetation Management (VM) programs by a total of $105.5 million, as follows[195]:

Program	Increases to 2021 Forecast (2018 Constant $)
Distribution Routine Vegetation Management	$71,190,000
Transmission Routine Vegetation Management	$2,926,000
Dead, Dying and Diseased Tree Removal	$10,438,000
Hazard Tree Management Program (aka Wildfire Vegetation Management)	$20,936,000

[194] Ex. SCE-13, Vol. 6 E2 (Jocelyn), p. 3, Table I-1.

[195] Ex. SCE-24 E (Landrith/Pham), p. 3, Table III-2.

Total	**$105,491,000**

Regarding this Update testimony, TURN's position, discussed in detail in Section 45 below, is that it exceeds the proper scope of Update testimony, which allows only limited opportunity for analysis and discovery and no opportunity for responsive intervenor testimony. To be clear, as explained in Section 45, TURN opposes SCE's effort by Update testimony to increase its forecast for all four of its VM programs.

In sum, as discussed below in Section 14.3, TURN recommends that SCE's Direct/Rebuttal 2021 forecast for HTMP be reduced by $38.2 million. And, as discussed in Section 45, TURN opposes any increase to the 2021 forecasts for any of SCE's VM programs based on SCE's Update testimony. As explained in Section 45, any costs that SCE incurs in excess of its adopted forecast should be tracked in a memorandum account and subject to recovery in its next GRC or a future application.

14.2 Routine Vegetation Management – Distribution

14.3 Wildfire Vegetation Management (a.k.a. Hazard Tree Management Program): SCE's Forecast for the Hazard Tree Management Program (HTMP) Is Excessive and Should Be Reduced In Order to Promote Improved Efforts at Targeting Removal of Green, Living Trees Beyond the GO 95 Clearance Zone

14.3.1 Overview of TURN's Position

SCE's HTMP forecast assumes that SCE will remove 20,000 green, living trees under this program in 2021, escalating to 25,000 in 2022 and 30,000 in 2023.[196] This tree removal forecast, in turn, is based on an assumption that SCE will perform "upwards of 250,000"[197] – *i.e.*,

[196] Ex. SCE-02, vol. 6A (Jocelyn), p. 37, Table II-12.

[197] *Id.*, p. 37: 2-3.

more than 250,000[198] -- tree assessments per year. The forecast also assumes that SCE will perform 100,000 "mitigations" per year[199] – that is actions less than tree removal, including removal of major tree branches, palm frond removal, and monitoring for the need for potential removal in the future.[200]

TURN does not dispute SCE's forecast to perform 100,000 mitigations per year under HTMP -- or the associated costs of those mitigations.[201] However, TURN strongly takes issue with SCE's proposal to remove an average of 25,000 trees per year in the rate case period, and the costs associated with that proposal. As discussed in the sections that follow, SCE has failed to show that a program that removes an annual average of 25,000 living, green trees per year -- trees that contribute to greenhouse gas reduction -- is necessary or appropriate, in light of the following: (1) HTMP is a discretionary program that supplements other compliance programs that already remove tens of thousands of hazardous trees every year; (2) removing tens of thousands of green trees every year is grossly excessive to address the risk of <u>significantly less than 200</u> tree-caused circuit interruptions in high fire risk areas (HFRA) per year; and (3) SCE's forecast number of assessments in this case significantly exceeds the sworn statements SCE made in its recent 2020-2022 Wildfire Mitigation Plan (WMP) regarding the number of

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[198] 4 RT 475: 23-26 (Jocelyn/SCE).

[199] Ex. TURN-37 (SCE -02, vol. 6 Excel Workpapers), PDF p. 5, Mitigation Workpaper showing 100,000 "trees to be trimmed" in each of 2021 through 2023. The claim by SCE's witness, Ms. Jocelyn, that SCE has "a much greater prescription rate for removal rather than trimming activities" (4 RT 500: 18-20) is directly contradicted by SCE's own forecast that it will perform 100,000 mitigations compared to 20,000 removals in 2021.

[200] Ex. SCE-02, vol. 6A (Jocelyn), p. 32: 6-8.

[201] Ex. TURN-02 (Borden), p. 44 (Table 11, showing no reduction in SCE's Mitigation forecast).

assessments SCE expected to be able to accomplish; SCE's WMP forecast supports the reasonableness of TURN's forecast in this case.

Rather than giving SCE the green light to proceed with a terribly unfocused program that amounts to literal overkill of living trees, the Commission should encourage SCE to do a better job of targeting removal of the trees that are most in need of that extreme measure. TURN recommends that SCE's tree removal forecast be cut back by 80%, to removal of 4,000 trees in 2021,[202] which is still <u>well more than 20 times</u> the number of annual tree-caused ignitions that SCE is trying to prevent. With this reduction in tree removals, TURN recommends that SCE's 2021 HTMP forecast be reduced to $20.738 million, which is a reduction of $35.45 million from SCE's forecast.[203] In addition, the Commission should direct that SCE's risk assessment process under HTMP expressly take into account the lost greenhouse gas reduction benefits of removing green, living trees.

14.3.2 HTMP Is a Discretionary Program that Supplements Other Programs That Remove and Mitigate Hazardous Trees

HTMP is a new program which had its first full year in 2019.[204] As a result, this is the first GRC in which this program is being considered. In addition, HTMP is a discretionary program that is not required in order to comply with VM requirements.[205] In this regard, HTMP

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202 Ex. TURN-02 (Borden), p. 43.

203 Ex. TURN-02 (Borden), p. 44, Table 11. Because SCE errata reduced its Program Management line item 2021 cost forecast for HTMP from $8.017 million to $5.268 million (a difference of $2.749 million) (Ex. SCE-02, vol. 6A E, p. 36, Table II-11), and because TURN's recommended cost for that line item remains unchanged, the difference between the SCE and TURN forecasts has gone down by $2.749 million, from $38.200 million to $35.451 million.

204 Ex. SCE-02, vol. 6A (Jocelyn), p. 35.

205 4 RT 463: 20-23.

supplements the other three compliance-related programs that SCE includes under the heading of VM. HTMP is limited to HFRA.[206]

In assessing the need to remove an average of 25,000 trees per year under HTMP, it is important to recognize that SCE's three other compliance-related programs already remove tens of thousands of trees per year that pose hazards to SCE's facilities. Under the two Routine VM programs, SCE maintains the required and recommended clearance distances between vegetation and SCE's lines,[207] which necessitates the removal of large numbers of trees every year. In addition, SCE also removes large numbers of trees every year under the Dead, Dying and Diseased (DDD) Tree Removal Program, which addresses trees that are dead or expected to die within one year[208] that are outside of the GO 95 clearance zone and that could fall into power lines.[209] In the four-year period from 2015 through 2018, SCE removed an average of 44,361 trees per year under these three programs.[210]

HTMP is thus a new program that supplements these three pre-existing compliance-related programs that already remove large numbers of high risk trees both within and outside the GO 95 clearance zone. In this first GRC to consider this new supplemental program, the Commission is called upon to assess whether SCE has justified removal of an additional 25,000 living trees per year.

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[206] Ex. SCE-02, vol. 6A, p. 31, line 11; 4 RT 492: 7-10 (Jocelyn/SCE).

[207] Ex. SCE-02, vol. 6A, p. 13: 1-3.

[208] 4 RT 471: 8-12 (Jocelyn/SCE).

[209] Ex. SCE-02, vol. 6A, p. 28: 19-21. SCE gives the example of a dead 100-foot tall tree that is rooted 70 feet from SCE's facilities.

[210] Ex. TURN-02 E2, p. 40, Figure 8. The annual average of the tree removals shown in Figure 8 for 2015-2018 is 44,361. SCE's data for 2019 showed 22,888 DDD and HTMP tree removals, but did not include removals under the two compliance programs (*id.*, pp. 40-41, fn. 125).

14.3.3 HTMP Targets Green, Living Trees that Contribute to Greenhouse Gas Reduction

Like the DDD program, HTMP targets trees outside the GO 95 clearance zone as far as 200 feet away from SCE's power lines, which SCE refers to as the Utility Strike Zone.[211] The key difference from the DDD program is that HTMP focuses on living, green trees.[212] SCE does not dispute that these green trees, which SCE seeks to remove in large numbers under the HTMP, contribute to greenhouse gas reduction.[213] Nevertheless, the risk-informed process that SCE states that it uses to decide which trees to address under HTMP <u>does not at any point take into account the greenhouse gas reduction benefits that are lost when a green tree is removed</u>.[214] This important gap in SCE's analysis may help to explain why the program is so overbroad, as discussed in Section 14.3.4 below.

Indeed, some of the trees targeted for removal under HTMP may be expected to live many years or even decades.[215] As SCE's witness, Ms. Jocelyn explained, the assessments that take place under HTMP <u>are not looking for the tree's propensity to die</u>, but rather its propensity to fall.[216] For this reason, it is important to recognize that a tree that "fails" SCE's assessment process under HTMP (which SCE sometimes refers to as a "failed tree") may in many cases be a tree that is free of disease and can be expected to live for a very long time. As discussed in the

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[211] Ex. SCE-02, vol. 6A, p. 30:13 to p. 31:3.

[212] Ex. SCE-13, vol. 06 (Jocelyn), p. 16: 6; 4 RT 468: 22-24 (Jocelyn/SCE).

[213] 4 RT 471: 14-17 (Jocelyn/SCE).

[214] 4 RT 472: 5-9 (Jocelyn/SCE).

[215] 4 RT 470: 19-22 (Jocelyn/SCE).

[216] *Id.*, lines 22-24.

next section, it defies logic to remove so many living, green trees to mitigate the actual risk that SCE has identified.

14.3.4 Removing an Average of 25,000 Green Trees Per Year in HTMP is (Literally) Overkill for a Risk that, According to SCE's Own Data, Is Posed by Approximately 200 Trees Per Year

The data that SCE relies upon to attempt to justify removing an average of 25,000 trees per year under HTMP simply do not justify so many tree removals. TURN emphasizes that the data that are cited in this section are SCE's data, interpreted conservatively to give SCE the benefit of the doubt. It is not necessary to rely on the slightly less conservative interpretations of that data presented in TURN's testimony to show just how overbroad SCE's proposed HTMP is.

The table below is the table of "tree caused circuit interruption" (TCCI) data that SCE presents in its direct testimony to justify the need for the HTMP: [217]

Tree Caused Circuit Interruptions	**2017**	**2018**
# of TCCIs caused by failure of a living tree or a portion of a living tree	448 (84%)	314 (77%)
# of TCCIs caused by a living tree falling into SCE's facilities[218]	102 (19%)	35 (8.5%)
# of TCCIs caused by dead, damaged, declining or deteriorated trees	39 (7%)	31 (7.5%)
# of TCCIs caused by other causes	47 (9%)	39 (15.5%)
Total of TCCIs	**534 (100%)**	**411 (100%)**

Even taking this information at face value, it fails to support the need for 20,000 tree removals in 2021, which would be more than 37 times as many tree removals as the 534 TCCIs that SCE

[217] Ex. SCE-02, vol. 6A, p. 33, Table II-10.

[218] The numbers in this row are a subset of the numbers in the row above. 4 RT 489: 18-23 (Jocelyn/SCE).

experienced in 2017 (the higher of the two years shown). When the 100,000 annual mitigations short of tree removal that SCE forecasts are added, SCE is proposing to remove or trim more than 224 times as many trees as TCCIs in its entire service territory.

However, SCE's data demonstrably overstate the number of tree contacts that cause ignitions that, in turn, can cause a wildfire. A TCCI is not an ignition; ignitions are a subset of TCCIs.[219] For example, a tree contact that occurs in wet or snowy weather is unlikely to cause an ignition, and even so, a wet weather ignition will not start a wildfire. SCE's witness Ms. Jocelyn acknowledged that ignitions are "a much smaller pool."[220] Indeed, in its Wildfire Management testimony, SCE reports only 21 vegetation-caused ignitions in HFRA from 2015-2018, an average of about 5 ignitions per year.[221] Yet SCE chose to use TCCIs "as a proxy" for wildfire risk from tree contacts.[222] This was a curious choice for a program with the purpose of preventing wildfires, not promoting reliability.

Moreover, even though HTMP is limited to HFRAs[223] and thus can only help to address TCCIs in HFRAs, SCE chose to present in its testimony TCCI data for both HFRAs and non-HFRAs.[224] In discovery, TURN obtained the following breakdown of the totals in the table above by HFRAs and non-HFRAs, adding data for 2015-2016 and 2019:[225]

TCCIs	**2015**	**2016**	**2017**	**2018**	**2019**

219 4 RT 491: 17-19 (Jocelyn/SCE).

220 4 RT 491: 28 (Jocelyn/SCE).

221 Ex. SCE-04, p. 15, Table II-5.

222 4 RT 491: 23 to p. 492: 6.

223 *Id.*, p. 492, lines 7-10 (Jocelyn/SCE).

224 *Id.*, p. 492, lines 11-16 (Jocelyn/SCE).

225 Ex. TURN-35, SCE response to DR TURN-SCE 82-7, Excel Attachment Tab (b), PDF pp. 6-8. "HFA" as used in this exhibit is the same as HFRA. 4 RT 494:15 (Jocelyn/SCE).

HFRA	129	191	213	139	215
Non-HFRA	275	354	321	272	330
Total	404	545	534	411	545

This table shows that, in every year, TCCIs in non-HFRAs significantly exceeded TCCIs in HFRAs. *Only the TCCIs in the shaded HFRA row are even relevant to the need for a program that is limited to HFRAs*. Over the five-year period from 2015-2019, SCE averaged 177 TCCIs in HFRAs.

This average annual number, 177 TCCIs, is the *outer bound* of the extent of the risk that the HTMP is supposed to address. In fact, it overstates the need for the HTMP – and in particular the need for tree removals -- in several respects. First, as noted above, the number of ignitions – which is the event a wildfire-prevention program like HTMP is supposed to prevent -- is much smaller than the number of TCCIs – around 5 per year. Second, as noted in Section 14.3.1, SCE forecasts that it will perform 100,000 mitigations other than tree removal each year. Those mitigations, which can include trimming of major branches and palm fronds, must address at least some of the tree contact risk; otherwise, there would be no point in doing it – on such a large scale.[226] Third, as SCE's witness acknowledged, the company's two Routine VM programs and its DDD program also "inherently" address TCCIs.[227] However, SCE does not track TCCIs by program type,[228] so there is no data to show just how many of the TCCIs are

[226] SCE's data shows that palm trees caused 22% of TCCIs in HFRAs from 2015-2019. (*Id.*, Ex. TURN-35, Tab (b), which provides a breakdown of TCCIs by tree species.) TURN's witness, Mr. Borden, pointed out that loose palm fronds can be blown long distances and cause a disproportionate share of tree contacts in Southern California. (Ex. TURN-02, p. 42: 1-6.)

[227] 4 RT 497: 18-19 (Jocelyn/SCE).

[228] Ex. TURN-32, SCE response to DR TURN-SCE 82-3.c; 4 RT 496: 4-20 (Jocelyn/SCE) (agreeing that the word "not" is missing from the DR response).

being addressed by the three compliance-related programs. In sum, the inescapable conclusion is that HTMP tree removals are warranted to address only a fraction of the 177 average TCCIs that SCE experiences annually.

Nevertheless, even if one extremely conservatively accepts (contrary to the indisputable evidence discussed above), that 177 annual TCCIs describes the risk that needs to be addressed by HTMP tree removals, that number of TCCIs cannot begin to justify removing an average if 25,000 green, living trees in 2021-2023 respectively. SCE's proposal would still mean that, for 2021, the company would remove <u>113 times more trees</u> than its historical annual average of TCCIs in HFRAs. TURN certainly appreciates and accepts that SCE and its arborists cannot identify the trees that need removal with precision,[229] but to remove more than 100 times as many trees as TCCIs, year after year, is quite literally overkill. By comparison, TURN's proposal to remove 4,000 trees in 2021 (5,000 in 2022 and 6,000 in 2023) would still amount to more than 22 times the annual average of TCCIs and should be more than sufficient to address the uncertainty in determining the trees that warrant removal.

Clearly, SCE's current conception of its HTMP assumes a grossly overbroad use of removals. These results are likely driven by SCE's "Tree Risk Calculator," which assigns a score to assessed trees based on selections under dropdown menus for a variety of characteristics, which are then weighted with scores agreed upon by SCE's internal arborists and consultants.[230] As TURN's witness, Mr. Borden pointed out, to the extent that this risk calculator has unduly low tolerance for any "defect" in a tree, it will produce unnecessary

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[229] Ex. SCE-13, vol. 6 (Jocelyn), p. 15: 10-17.

[230] *Id.*, p. 17: 20 to p. 18: 23.

removal of trees that do not pose an actual risk of ignition.[231] TURN has previously recommended, and SCE agreed in a settlement that was adopted in A.18-09-002, to an independent study to evaluate the effectiveness of its current risk calculator in reducing wildfire risk.[232]

In the meantime while the final results of that study are pending, the Commission should not endorse SCE's extremely overbroad designation of trees for removal under HTMP. In a data request response, SCE stated that it has "no timeline" to achieve an improved level of precision in its work,[233] and SCE's witness could not identify any dates for any steps to improve its targeting of green trees that warrant removal. Ex. TURN-33.[234] The Commission needs to send a message that SCE should make it a priority to tighten up its evaluation criteria and do a better job of targeting its HTMP efforts. The best way to do so is to adopt TURN's more reasonable forecast of the number of trees that warrant removal.

Finally, with respect to SCE's TCCI data, it should be noted that the 2019 results of SCE's new HTMP, which actually started in late 2018, do not support a large and costly program. The table of HFRA data provided earlier in this section shows that, from 2015-2018, SCE averaged 168 TCCIs per year. In 2019, TCCIs <u>rose</u> to 215, significantly <u>more</u> than the prior 4-year average. At a minimum, the 2019 data do not provide any evidence that the HTMP had any impact on TCCIs or provided any substantial risk reduction.

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[231] Ex. TURN-02 (Borden), p. 43: 1-3.

[232] *Id.*, p. 43: 3-5; D.20-04-013, p. 18.

[233] Ex. TURN-33, SCE response to DR TURN-SCE-82-5.a-c.

[234] 4 RT 502: 9-14 (Jocelyn/SCE).

14.3.5 SCE's Forecast Number of Assessments, A Key Element on Which Its Tree Removal Forecast Relies, Is Unrealistically High and Conflicts With Its Sworn Wildfire Mitigation Plan

As noted in Section 14.3.1 above, SCE's forecast for tree removals under HTMP depends on its forecast for number of trees it will assess, multiplied by its assumed "failure rate," i.e, the rate by which trees "fail" the assessment and are designated for removal.[235] Despite the importance of the number of assessments to determining its tree removal forecast, SCE has been unable to settle on a consistent forecast of assessment volume both in this case and in the contemporaneous 2020-2022 WMP proceeding. As explained in this section, the Commission should not find credible the forecast of assessments – and hence the forecast of tree removals – that SCE has presented in this case.

SCE's forecasts for the number of assessments – and by implication failure rates -- have been a moving target in this case. In its amended direct testimony, dated November 22, 2019, SCE stated that it was forecasting "upwards of 250,000" tree assessments in 2020 and subsequent years.[236] To arrive at the forecast of 20,000 tree removals for 2021 implies a failure rate of 8%. However, in its rebuttal testimony, SCE stated that it intends to achieve an annual assessment level of <u>167,000</u> assessments between 2020 and 2022,[237] which implies a failure rate of 12% for 2021). And, in her oral testimony, Ms. Jocelyn acknowledged that SCE's estimates of the number of annual assessments varied considerably, from 144,000 to 360,000.[238] Thus, in

[235] 4 RT 473: 1-11 (Jocelyn/SCE).

[236] Ex. SCE-02 vol. 6A (Jocelyn/SCE), p. 37: 2-3. Ms. Jocelyn stated that "upwards of" means more than 250,000. 4 RT 475: 23-26 (Jocelyn/SCE).

[237] Ex. SCE-13, vol. 6 (Jocelyn), p. 19: 10-17.

[238] 4 RT 477: 7-11 (Jocelyn/SCE). SCE's rebuttal added: ". . . if necessary, SCE can achieve 250,000 assessments, and based on the estimated failure rate of 5 percent to 12 percent, [SCE can] deliver on the volumes in SCE's GRC forecast." The quoted rebuttal testimony reflects a

two different pieces of testimony in this case, SCE changed its 2021 forecast from more than 250,000 assessments to 167,000 assessments and in oral testimony indicated that the assessment level could be as low as 144,000.

In between its direct and rebuttal testimony, on February 7, 2020, SCE presented its 2020-2022 WMP, which was verified under oath by SCE's Senior Vice President.[239] In that WMP, SCE explained that it was decreasing its "HTMP assessment volume targets . . . from 125,000 in the 2019 WMP to 75,000 in the 2020-2022 WMP."[240] SCE gave three detailed reasons for this reduced forecast, including: (1) the challenges SCE faced in 2019 in "attracting and retaining ISA-certified professionals to perform assessments, given the high demand for arborists in California and nationally"; and (2) significant variations in the productivity rate of trees assessed per day – to meet the 2019 target, SCE had to re-locate assessors from lower productivity areas to higher productivity areas, an option that will be less available as more areas are assessed.[241] SCE's witness Ms. Jocelyn acknowledged that these concerns were accurate and correct, but tried to claim that they were limited to conditions expected in 2020.[242] However, at least two of the three issues – the ones described above – are clearly persistent concerns. Indeed, the issue of limited flexibility to move resources to higher productivity areas will only increase as SCE expands its footprint of assessed areas.

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misunderstanding on SCE's part of the purpose of a GRC forecast, which in this instance should be a good faith forecast of the expected number of assessments, not a number that they can strain to justify "if necessary."

239 4 RT 480: 5-22 (Jocelyn/SCE).

240 Ex. TURN-36 (SCE 2020-2022 WMP), p. 157 (emphasis added).

241 *Id.*

242 4 RT 482: 28 to p. 483: 11 (Jocelyn/SCE).

SCE concluded the HTMP assessment target discussion in its 2020-2022 WMP by affirming the soundness of its forecast of 75,000 assessments:

> *The 2020-2022 target of 75,000 assessments per year was set based on the average number of assessors with established availability and achievable assessment productivity*.[243]

Thus, after claiming in its November 2019 testimony in this case that 250,000 annual assessments was a reasonable forecast for 2021-2023, SCE's February 2020 WMP gave a thorough and convincing explanation, under oath, for why the company should be expected to achieve only 75,000 assessments per year in each of 2020-2022 – a span that obviously includes the 2021 test year. Ms. Jocelyn acknowledged that nothing in the 2020-2022 WMP indicated that 75,000 was meant to be a target only for 2020.[244]

In discovery, TURN asked SCE to explain the discrepancy between its WMP forecast of assessments and the forecast in this case. In response, SCE tried to explain away its WMP target of 75,000 as meant to apply only to 2020:

> SCE chose to keep the WMP goal at the 2020 level of 75,000 assessments for the entire WMP period <u>rather than guess at how high the number would go</u>, knowing that it would be revised in the future.[245]

By admitting that any attempt <u>in February 2020</u> to forecast assessments in 2021 would just be a "guess," SCE also effectively admitted that its forecast <u>prepared several months</u> earlier was indeed nothing more than a guess. SCE's response only serves to underscore why its forecasts

[243] Ex. TURN-36 (SCE 2020-2022 WMP), p. 157 (emphasis added).

[244] 4 RT 482: 28 to p. 483: 11 (Jocelyn/SCE).

[245] Ex. TURN-31, SCE response to TURN-SCE 82-2 (emphasis added).

here should not be considered anything more than wishful thinking that serves to increase its revenue requirement.

TURN submits that SCE's target of 75,000 assessments in its WMP is far more credible than the 250,000 figure in its testimony in this case. Ms. Jocelyn pointed out in her oral testimony that the numbers included in the WMP "become a compliance target to achieve." As she further explained: "Certainly the number we put in the Wildfire Mitigation Plan we want to be very achievable."[246] Indeed, SCE is subject to penalties for failure to comply with its WMP.[247] For the detailed reasons given in SCE's WMP, 75,000 assessments is a realistic and achievable forecast for this case. SCE should not be allowed to game the WMP and GRC proceedings by benefitting from an inflated forecast that will serve to increase its revenue requirement in this case, but that it was not willing to stand by in its WMP.

SCE's rebuttal claimed that TURN's forecast for an average of 5,000 tree removals from 2021-2023 was "arbitrary and flawed."[248] Yet when SCE's own figure of 75,000 assessments is used, TURN's forecast falls within the failure rate range of 5% to 12% identified by SCE.[249] TURN's average of 5,000 removals implies a failure rate of 6.7% and its 2021 forecast of 4,000 removals implies a 5.3% failure rate. As discussed in Section 14.3.4, TURN's removal forecast is primarily based on trying to prevent an overbroad destruction of green trees while still allowing for ample uncertainty in determining the trees that warrant removal. Yet TURN's

[246] 4 RT 523: 8-27 (Jocelyn/SCE).

[247] Public Utilities Code § 8386.1.

[248] Ex. SCE-13, vol. 6 (Jocelyn), p. 14: 15.

[249] Ex. SCE-02, vol. 6A (Jocelyn), p. 36: 13-14.

forecast can also be justified by using SCE's own numbers for assessments from its WMP and failure rates from this case.

14.3.6 Other Reasons to Reduce the Proposed Scope of the HTMP

TURN's testimony provides other reasons to significantly reduce the number of tree removals proposed by SCE.

In light of the workforce constraints faced by all utilities in their vegetation management efforts, it is especially important to direct limited labor resources to the work that is most effective in reducing wildfire risk. As noted in Section 14.3.5, SCE's 2020-2022 WMP emphasized the challenges it faces in obtaining qualified VM personnel, specifically noting that HTMP pruning and removal workers "draw from the same pool as those who perform compliance distance trimming, creating labor constraints."[250] Focusing VM efforts on costly and labor-intensive tree removal beyond the GO 95 clearance zone risks diverting funding and scarce resources from the compliance-related programs, which have a longer track record of reducing risk.[251]

In addition, in its review of the 2020-2022 WMPs, the Wildfire Safety Advisory Board (WSAB) pointed out that enhanced vegetation management (EVM) programs, like SCE's HTMP, may be counter-productive. WSAB explained that "[t]he removal of certain species can lead to an infill of dry grass, which may create a *more flammable* environment."[252] Given questions about whether removal of species is beneficial in mitigating risk, WSAB questioned

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[250] Ex. TURN-36, SCE 2020-2022 WMP, p. 157.

[251] Ex. TURN-02 (Borden), p. 42: 9-24.

[252] Ex. TURN-02, p. 41: 14-15, quoting WSAB Recommendations on Utility 2020 WMPs, April 15, 2020, found in Ex. TURN-02-Atch 1-E, p. 225.

whether the utilities should continue their efforts outside the GO 95 12-foot radius, "especially given the cost of these efforts."[253]

14.3.7 Summary of TURN's Recommendations

For the foregoing reasons, SCE's forecast for tree removals under HTMP should be reduced by 80% to an average of 5,000 removals in 2021-2023 – and 4,000 removals in 2021. This amounts to well in excess of 20 times more removals than the average number of TCCIs SCE has historically experienced and thus still provides a significant margin to reflect the uncertainty in earmarking trees that could come into contact with SCE's facilities. In addition, TURN's forecast falls within SCE's failure rate range when the number of forecast assessments is made consistent with SCE's statements in its WMP regarding a realistic and achievable volume of assessments. This reduction to SCE's forecast of tree removals reduces SCE's 2021 forecast for this program by $35.45 million to $20.74 million.[254] Finally, SCE should be directed to include the impact of lost greenhouse gas reduction benefits in its risk assessment model that determines whether green, living trees should be removed under HTMP.

14.4 Other Issues

15. WILDFIRE MANAGEMENT

15.1 Overview

[253] *Id.*, p. 41, lines 15-18, found in Ex. TURN-02-Atch 1-E, p. 226.

[254] Ex. TURN-02 (Borden), p. 44, Table 11. Because SCE errata reduced its Program Management line item 2021 cost forecast for HTMP from $8.017 million to $5.268 million (a difference of $2.749 million) (Ex. SCE-02, vol. 6A E, p. 36, Table II-11), and because TURN's recommended cost for that line item remains unchanged, the difference between the SCE and TURN forecasts has gone down by $2.749 million, from $38.200 million to $35.451 million.

SCE proposes significant investment in wildfire mitigation efforts, driven primarily by an extraordinary expansion of covered conductor over the rate case period.[255] SCE's wildfire mitigation strategy takes an "all in" approach to covered conductor and proposes the installation of as many miles of covered conductor as possible between 2019 and 2023.[256] SCE's "all in" approach would cost ratepayers $2.7 billion over the rate case period, 2021-2023.[257] TURN's alternative would deploy covered conductor on SCE's highest risk segments during the rate case period and ensure that each ratepayer dollar provides significant safety benefits consistent with just and reasonable rates.[258] TURN's recommended budget for covered conductor is $642.8 million over the rate case period.[259] On a relative risk basis, despite costing ratepayers $2 billion dollars less than SCE's proposal, TURN's proposed budget is sufficient to deploy covered conductor on circuits representing more than 90% of wildfire risk.[260]

TURN recommends other adjustments to SCE's forecast for tree attachments and pole replacement consistent with a narrower deployment of covered conductor. Additionally, to the extent the installation of covered conductor results in the retirement of relatively new assets, TURN recommends the replaced assets be removed from rate base.

TURN also recommends the Commission reject SCE's proposal to replace all vertical switches in the HFTD, regardless of whether their physical condition during an inspection

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[255] Ex. SCE-15, Vol. 5 (Roy), Fig. I-3, p. 6

[256] 8 TR 930:6-9 (SCE/Roy): "the maximum amount of covered-conductor miles due to resource constraints that we could execute over that five-year period."

[257] Ex. SCE-15, Vol. 5 (Roy), Table II-6, p. 12.

[258] Ex. TURN-02 (Borden), p. 1:18-24.

[259] Ex. SCE-15, Vol. 5 (Roy), Table II-6, p. 12.

[260] Ex. TURN-02 (Borden), p. 14:10-17.

demonstrates the asset poses any risk. SCE has not demonstrated that wholesale replacement is reasonable or necessary.[261] Finally, TURN recommends that the Commission reject proposed funding of Distribution Fault Analysis (DFA) pending the final results of the utility's ongoing DFA pilot.[262]

15.2 Covered Conductor Program: TURN's Proposed Covered Conductor Budget Addresses SCE's Highest Risk Circuits at a Reasonable Cost.

SCE proposes significant expenditures to address wildfire, its top public safety risk, requesting $733,024,000 for covered conductor in Test Year 2021 alone, and increasingly higher amounts in 2022 and 2023, for a total of $2.7 billion for 2021-2023.[263] Ultimately, SCE seeks approval of costs related to the installation of 6,200 circuit miles of covered conductor in the utility's High Fire Threat District (HFTD) between the years of 2019-2023 at a total price tag of $3.4 billion.[264] As explained by SCE Witness Roy, SCE sized its deployment based on the "maximum amount of covered-conductor miles due to resource constraints that [SCE] could execute over that five-year period" rather than considerations of cost-effectiveness or affordability.[265] However, the proposed maximum deployment of covered conductor comes at a steep price tag and corresponding impact on affordability; indeed, SCE's covered conductor proposal represents 90% of its wildfire capital request.[266]

[261] Ex. TURN-02 (Borden), p. 1:16-17.

[262] Ex. TURN-02 (Borden), p. 1:13-15.

[263] Ex. SCE-54, p. 190.

[264] Ex. SCE-15, Vol. 5 (Roy), p. 14:20; Ex. SCE-54, p.190.

[265] 8 TR 930:6-9 (SCE/Roy).

[266] Ex. TURN-02, Figure 1, p. 5.

TURN agrees that covered conductor plays an important part in wildfire mitigation efforts and proposes a budget sufficient to fund the installation of over 2,500 circuit miles of covered conductor between 2021 and 2023.[267] The TURN budget better incorporates affordability concerns, targeting ratepayer dollars at the highest risk circuits while still providing for a significant expansion of covered conductor- likely the largest in the world.[268] Acknowledging that no single mitigation is sufficient to address wildfire risk, TURN recommends only limited changes to the remainder of SCE's budget for wildfire mitigation. Specifically, TURN does not oppose SCE's proposed 2021forecast for Enhanced Overhead Inspections and Remediations (aside from adjustments related to vertical switches), Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.[269]

In sum, the Commission should reject SCE's forecast for covered conductor in favor of TURN's forecast. TURN's proposal targets scarce ratepayer dollars at the highest risk circuits consistent with the principles of just and reasonable ratemaking. TURN takes no position at this time on the scope of installation of covered conductor beyond the rate case period; TURN recommends a narrower scope in this case, chiefly to adjust the pace of covered conductor installation to limit the deleterious impact on short-term and long-term customer rates.

TURN's recommendation is fully consistent with safety, and any utility arguments framing it as otherwise are disingenuous at best. SCE suggests that TURN's proposal to slow the pace of covered conductor installation and reduce the associated forecast leaves Californians

[267] Ex. TURN-02, p. 1:18-24.

[268] Ex. TURN-02, p. 6:23-24.

[269] Ex. SCE-15, Vol. 5 (Roy), Table I-3, p. 6.

susceptible to undue risk.[270] Consistent with precedent, the Commission should reject any such suggestion outright:

> DRA and TURN represent ratepayer interests which may well be at odds with employee or management or shareholder interests during a GRC. That does not mean that recommended cuts equate with a 'pathology of indifference' or blatant disregard of safe operations, or a failure to see linkage between maintenance and reliability, for example. It means that these parties view SCE's methods and activities through a different lens of reasonableness.[271]

It is in the best interest of both shareholders and ratepayers that SCE avoid catastrophic wildfires. TURN proposes that, in recognition of both safety and affordability concerns, SCE employ a suite of wildfire mitigations while adjusting the pace at which one of its highest cost mitigations is deployed. As stated above, TURN has not opposed multiple other mitigations proposed by the utility, and SCE has or will spend considerable sums from 2018-2020 to mitigate wildfire risk.

15.2.1 SCE Has Not Targeted Deployment of Covered Conductor Consistent with Just and Reasonable Rates

As stated by the Commission, "[v]irtually everything a utility does [has] some nexus to safety," thus "the emphasis should be on those initiatives that deliver the optimal safety."[272] Rather than scoping its program by identifying those circuits where the utility can achieve "optimal safety improvement in relation to the ratepayer dollars spent,"[273] SCE's proposed covered conductor program is constrained only by the limits of the utility's resources to install

[270] Ex. SCE-12, Vol. 1 (Payne), p. 8:19-21.

[271] D.12-11-051, p. 32.

[272] D.14-08-032, p. 28.

[273] D.14-08-032, p.28.

covered conductor.[274] In its review of the SCE Wildfire Mitigation Plan (WMP), the Commission describes the SCE covered conductor proposal:

> Southern California Edison Company (SCE) takes an "all in" approach to the deployment of covered conductor at significant cost with minimal analysis of alternatives or analysis of why this tool warrants extensive use.[275]

SCE Witness Roy explained that SCE's program was sized based on "the maximum amount of covered-conductor miles due to resource constraints that we could execute over that five-year period."[276]

Even though a narrow subset of miles reflects SCE's highest risk circuits, the utility has not used this knowledge to set the pace of its deployment of a costly wildfire mitigation to first target the highest risk segments.[277] SCE has risk analysis capabilities that will allow it to prioritize deployment of covered conductor to the riskiest segments first. SCE states that it "continue[s] to refine our risk analysis to better target the spans that pose the highest risk, and that is where we are focusing our grid hardening efforts."[278] However, rather than use these risk analyses to target the scope and pace of covered conductor installation, SCE uses the detailed information it has on each circuit only to identify the order of circuits for hardening: "The prioritization is driven by risk which is the product of probability and consequence."[279] TURN's

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[274] 8 TR 930:6-9 (SCE/Roy).

[275] WSD-004 (R.18-10-007), p. 10.

[276] 8 TR 930:6-9 (SCE/Roy).

[277] Ex. TURN-02-Atch-01 (Borden), p. 177: "REAX data stratification for HFRA identifies 2161 circuit miles present approximately 93.87% of the risk-consequence for SCE."

[278] Ex. SCE-01, Vol. 1, p. 18:24-25.

[279] Ex. TURN-02-Atch-01 (Borden), p. 137.

criticism of SCE's failure to target ratepayer spending is consistent with the Commission's findings on SCE's WMP: "SCE does not show that it is targeting deployment of initiatives to the highest-risk areas."[280] The Commission further found that "SCE provides little analysis justifying where it targets grid hardening programs for the greatest risk reduction."[281]

SCE's failure to target its spending at the highest risk circuits leaves the SCE plan unaffordable for its customers. SCE's plan to install as much covered conductor as possible does not include a consideration of the program's impact on affordability. While the utility claims that affordability was a part of its considerations designing its proposed program,[282] SCE has not identified what it considers to be cost-prohibitive.[283] Without a threshold for understanding affordability, SCE cannot demonstrate that its proposal is consistent with just and reasonable rates. Especially given the economic uncertainty facing ratepayers in the face of the Covid-19 pandemic, SCE's additional $2 billion for covered conductor on relatively low risk circuits is not just and reasonable.

As described further below, TURN relied on the detailed risk information the utility has developed on its circuits to scope TURN's budget for covered conductor.[284] TURN used the risk profile of each circuit segment not just to identify the order of deployment but to size the

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[280] WSD-004 (R.18-10-007) at 27.

[281] WSD-004 (R.18-10-007) at 10.

[282] 3 TR 334:11-17 (Payne): "A What I'm saying is that based on the safety risk that exists and the evaluation of the options that we have to mitigate that risk and all the other factors that I just described, we would arrive at our proposal, which would be what we think is overall the best approach for our customers."

[283] Ex. SCE-47, p.1: "SCE does not maintain a specific percentage increase term or threshold for what would be considered "cost-prohibitive" in this situation."

[284] Ex. TURN-02 (Borden), pp. 14:8-20:8.

program ensuring that each dollar of SCE's spending achieves "optimal safety improvement." As a result, TURN's proposal results in safety improvements at a more affordable cost to ratepayers.

15.2.2 TURN's Alternative Covered Conductor Proposal is Consistent with Just and Reasonable Rates and Should Be Adopted

While TURN offers an alternative scope, TURN supports SCE's reliance on covered conductor as a mitigation "given its potential to significantly reduce wildfire risk, particularly from vegetation contact."[285] TURN's proposal, in essence, addresses the concerns expressed in Resolution WSD-004 that SCE is not "targeting deployment of initiatives to the highest risk areas."[286] Recognizing the failure of SCE to propose a covered conductor program consistent with just and reasonable rates, TURN witness Borden recommends that the information SCE has on each of its circuits be used to develop the scope of the program in the rate case period. Based on this information, TURN proposes a budget sufficient to install 2,581 miles of covered conductor on SCE's highest risk segments.[287]

SCE's deployment prioritization model illustrates that risk is not consistent from circuit to circuit, and, indeed, SCE intends to address the highest risk segments first.[288] If each circuit has a different risk profile, but hardening costs are consistent from circuit to circuit, the cost efficiency of hardening each circuit will vary. Riskier circuits will be more cost-efficient to address, with cost-efficiency declining with each relatively less risky circuit. In Figure 5,

[285] Ex.TURN-02 (Borden), p.11:17-18.

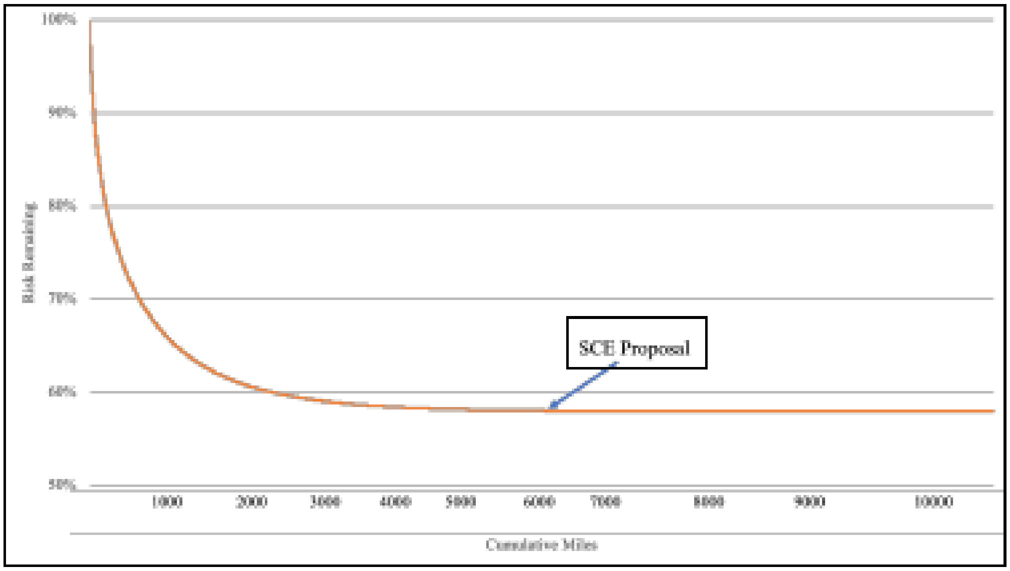
[286] WSD-004 (R.18-10-007), p. 27.

[287] Ex. TURN-02 (Borden), p. 22:21-24:2.

[288] Ex.SCE-001, Vol. 1 (Payne), p. 18:24-25.

reproduced below, TURN witness Borden's testimony illustrates the risk reduction potential of each additional mile of covered conductor installed:[289]

Ex. TURN-02 Figure 5 Wildfire Risk v Cumulative HFRA Miles; SCE GRC Risk Analysis[290]



The steep decline in Ex. TURN-02 Figure 5 demonstrates that SCE's highest risk segments are fairly concentrated. As the slope begins to flatten, each additional mile is less risky on a relative basis. TURN's proposed program focuses ratepayer spending on those circuits that present the most risk.

Based on SCE's prioritization model, TURN's budget is sufficient to address over 90% of SCE's wildfire risk at a fraction of the cost. The Commission has previously adjusted utility budgets accordingly when a utility proposes spending inconsistent with cost efficiency. Specifically, in D.10-06-048, the Cornerstone Decision, the Commission reduced spending on a PG&E reliability project noting that "up to 68% of the quantifiable reliability improvement

[289] Ex. TURN-02 (Borden), Fig. 5, p.20.

[290] Ex. TURN-02 (Borden), Fig. 5, p.20.

benefits identified in PG&E's Cornerstone Improvement Project proposal can be achieved for [] approximate[ly] 18% of the requested costs."[291] Costs that were rejected "[we]re done so without prejudice,"[292] and PG&E was directed that in the future it should demonstrate not just need but also that the chosen alternative is the "optimal solution."[293] Similarly, here, TURN's proposal does not seek to preclude additional future spending on covered conductor, only to limit the scope of covered conductor included in this rate case period.

15.2.3 That SCE's Covered Conductor Addresses More Absolute Risk than TURN's Covered Conductor Program Ignores Affordability

"SCE agrees that the installation of covered conductor in the first few years of the [covered conductor] program will likely capture greater per-mile risk reduction than the miles of conductor covered in the later years of the program."[294] Despite acknowledging declining cost efficiency, SCE argues that TURN's proposal should be rejected as "leav[ing] substantial risk on the system."[295]

As SCE explains, its prioritization curve measures relative risk, rather than absolute risk.[296] In other words, the circuits higher on the curve have a higher risk profile in comparison to circuits further down the curve. The risk curve is so steep because, as SCE acknowledges,

[291] D.10-06-048, p.1.

[292] D.10-06-048, p.1.

[293] D.10-06-048, p. 2-3: "In developing future reliability improvement programs or projects PG&E must be able to demonstrate the need for such programs or projects, and if there is a need, whether the program or project represents the optimal solution when considering alternatives and cost-effectiveness in the identification and prioritization processes."

[294] Ex.SCE-15 (Roy), Vol.5, p. 21:1-3.

[295] Ex.SCE-15 (Roy), Vol.5, p. 21:3-5.

[296] Ex.SCE-15 (Roy), Vol.5, p. 21:6-14.

"certain circuit segments have extraordinarily high risk values."[297] SCE argues that TURN's proposal to target deployment of covered conductor during this rate case period at the riskiest circuits leaves a significant amount of absolute risk not addressed within the rate case. TURN agrees that SCE's proposal will address more risk, but SCE's proposal also costs ratepayers $2 billion more at a time where ratepayers are unable to bear such significant rate hikes.

In its Rebuttal Testimony, SCE uses tranches of 1,250 miles along the risk curve to demonstrate the absolute risk of the circuits that would remain unhardened in this rate case period under TURN's program. SCE's illustrations of absolute risk demonstrate, however, that TURN's proposal to harden just over 2,500 miles will still address a significant amount of risk. Table II-7 of SCE's Rebuttal Testimony, reproduced below, demonstrates that the first 2,500 miles on the risk curve represent not just a relatively higher risk profile or "Reax Score" but also the circuit miles with the greatest consequences per mile.[298]

[297] Ex.SCE-15, Vol. 5 (Roy), p. 21:13-14.

[298] Ex.SCE-15, Vol. 5 (Roy), Table II-7, p. 22.

Ex. SCE-15, Vol. 5 Table II-7: Average Wildfire Consequence Along the Relative Risk Buydown Curve[299]

Tranches of Cumulative Miles on Risk Curve	Average Reax Score for Tranche[50]	Average Wildfire Consequence per Mile for Tranche[51]
0-1,250	6,849	272 structures and 33,036 acres
1,251-2,500	1,291	107 structures and 16,830 acres
2,501-3,750	371	69 structures and 8,617 acres
3,751-5,000	104	42 structures and 4,102 acres
5,001-6,250	24	23 structures and 1,597 acres
6,251-7,500	3	9 structures and 334 acres
7,501+	0	1 structure and 23 acres

Using the average REAX scores shown in the Table shows that 94% of total risk is contained within the top 2,500 circuit miles. While every additional mile of covered conductor SCE would install under its program would address additional wildfire risk, that does not mean each additional mile represents "optimal safety" consistent with just and reasonable rates.

SCE also notes that TURN's proposal would leave unhardened circuits with critical customers and critical infrastructure facilities.[300] While these circuits may not be hardened under TURN's proposal, this does not mean that there will be no wildfire mitigation on these circuits. As discussed further in Section 15.2.5 below, these circuits will still be subject to other wildfire mitigations which TURN has left largely unopposed.

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[299] Ex.SCE-15, Vol. 5 (Roy), Table. 11-7, p. 22.

[300] Ex.SCE-15, Vol. 5 (Roy), Fig. 11-2, p. 24.

15.2.4 TURN's Covered Conductor Recommendation Addresses Operational Requirements and SCE's Riskiest Circuits at a Just and Reasonable Cost

SCE argues that TURN does not account for SCE's operational considerations installing covered conductor, specifically the extra 20% covered conductor required for efficient installation.[301] As an initial matter, SCE did not highlight the need for this operational buffer until its rebuttal testimony. Regardless of SCE's initial failure to identify the need for a buffer, TURN's proposal for the installation of 2,581 miles of covered conductor is sufficient to include an operational buffer while still addressing significant risk.

Accounting for the operational buffer, TURN's budget would fund the installation of 2,150 miles and provide funding for 430 miles as an operational buffer. It is not clear whether the additional 430 miles is outside or within the top 2,600 riskiest circuit miles; SCE's rebuttal did not address this issue. However, even if the Commission assumes that the buffer miles would not address the highest risk circuits, the top 2,150 riskiest circuit miles represent would still address most of the identified wildfire risk because: "REAX data stratification for [High Fire Risk Areas] identifies 2,161 circuit miles [which] represent approximately 93.87% of the risk consequence for SCE."[302] Thus, a 20% operational buffer, even if this incorporates relatively low-risk areas, does not undermine the potential for TURN's proposal to address SCE's riskiest segments at a significant cost savings relative to SCE's proposal.

SCE's Rebuttal Testimony also argues that TURN's proposal is insufficient because it does not provide for the installation of additional covered conductor that would allow SCE to

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301 Ex.SCE-15, Vol. 5 (Roy), p. 28:1-3.

302 Ex. TURN-02-Atch-01 (Borden), p. 177.

further sectionalize circuits and potentially reduce PSPS events.[303] Rather than quantify the overage that this operational requirement necessitates, SCE notes that the additional deployment of miles required for sectionalizing "will be determined on a case-by-case basis during scoping & design based on the feasibility to operationalize this benefit."[304] It is inappropriate to reject or adjust the scope of TURN's proposal for the purposes of reducing PSPS because SCE cannot guarantee that additional covered conductor would result in fewer PSPS events. SCE specifically "cannot commit to not calling PSPS for circuits or circuit segments where covered conductor has been deployed because the decision of whether to conduct a PSPS de-energization is based on many factors."[305] To the extent that SCE will not commit to reduce PSPS, the unquantified increase in covered conductor costs required to avoid these events is unsupported and unjustified.

TURN notes that it does not propose the specific circuits that SCE should harden in this rate case period; instead it provides the utility with a substantial budget for its hardening work. To the extent that the utility further refines its model and identifies a different prioritization of high-risk circuits, the utility can make those changes during the rate case period.

15.2.5 Effective Wildfire Risk Management Relies on a Suite of Mitigations, Many of Which are Unopposed

Every circuit on SCE's system, especially those in the HFRA, is vulnerable to wildfire. While the Commission has tools to help understand the potential consequences of wildfire and

[303] Ex. SCE-15, Vol. 5 (Roy), p. 28:22-25.

[304] Ex. SCE-15, Vol. 5 (Roy), p. 29:1-2: SCE does not address how these additional miles interact with the 20% of operational buffer it also requests.

[305] Ex. SCE-47 (Roy), p.7.

the more likely locations for a catastrophic wildfire, no one can identify with any certainty where the next wildfire will occur. Ideally, every circuit would have the all mitigations in place to protect against ignitions, but as SCE notes, this is not cost effective or acceptable to customers.[306] Even with the most expensive, and effective, mitigations in place, it is not certain the utility could prevent every ignition. Given that "many potential ignitions – given the wrong conditions – could turn into the next catastrophic wildfire event," TURN agrees with SCE that it is advisable to deploy multiple mitigations across its HFRA to mitigate risk as efficiently and effectively as possible.[307] The discussion of covered conductor, one of the highest cost mitigations, must be in the context of the multiple other investments ongoing at SCE, many of which TURN does not oppose – Vegetation Management compliance-related programs, Enhanced Overhead Inspections and Remediations, Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.

While covered conductor provides significant benefits, it does not reduce all risk of a catastrophic wildfire. SCE acknowledges that "[c]overed conductor is not 100% effective in reducing all ignitions."[308] Even where covered conductor is installed, approximately 40% of wildfire risk remains.[309] It follows that an effective wildfire mitigation strategy relies on a variety of wildfire mitigations, not just one. As SCE states:

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[306] Ex. SCE-15, Vol. 5 (Roy), p. 29:20-23: "Undergrounding, as a program, does mitigate most risk drivers, however, it is financially prohibitive and practically infeasible from a widespread deployment perspective – SCE has over 9,600 circuit miles in its HFRA, and many of these miles are in areas with terrain prohibitive to undergrounding."

[307] Ex. SCE-12, Vol. 1 (Payne), p. 7:15-17.

[308] Ex. SCE-47 (Roy), p. 3.

[309] Ex.TURN-02-Atch 01 (Borden), p.1.

> To adequately address wildfire risk, it is often necessary to deploy multiple mitigation measures on a given circuit whether or not covered conductor is installed. For example, on circuits that either have covered conductor installed or not, SCE will continue to perform inspections, repair equipment as necessary, follow recommended and required vegetation management practices, etc.[310]

Provided that SCE will be pursuing its suite of mitigations across its system, the failure to deploy covered conductor in any one location does not mean that there are no mitigation measures in place for that circuit. SCE notes that "destructive wildfires recently have occurred in SCE's service territory on circuit miles located in areas on the risk buy-down curve that TURN would want to leave uncovered."[311] Uncovered is not the equivalent of unprotected.

As the Commission has observed, the potential for safety impact does not mean a program is an efficient use of ratepayer funding.[312] SCE relies on Figure II-3 (reproduced below) to demonstrate that fires have occurred further down SCE's risk buy down curve than where TURN's proposed conductor deployment would stop.[313]

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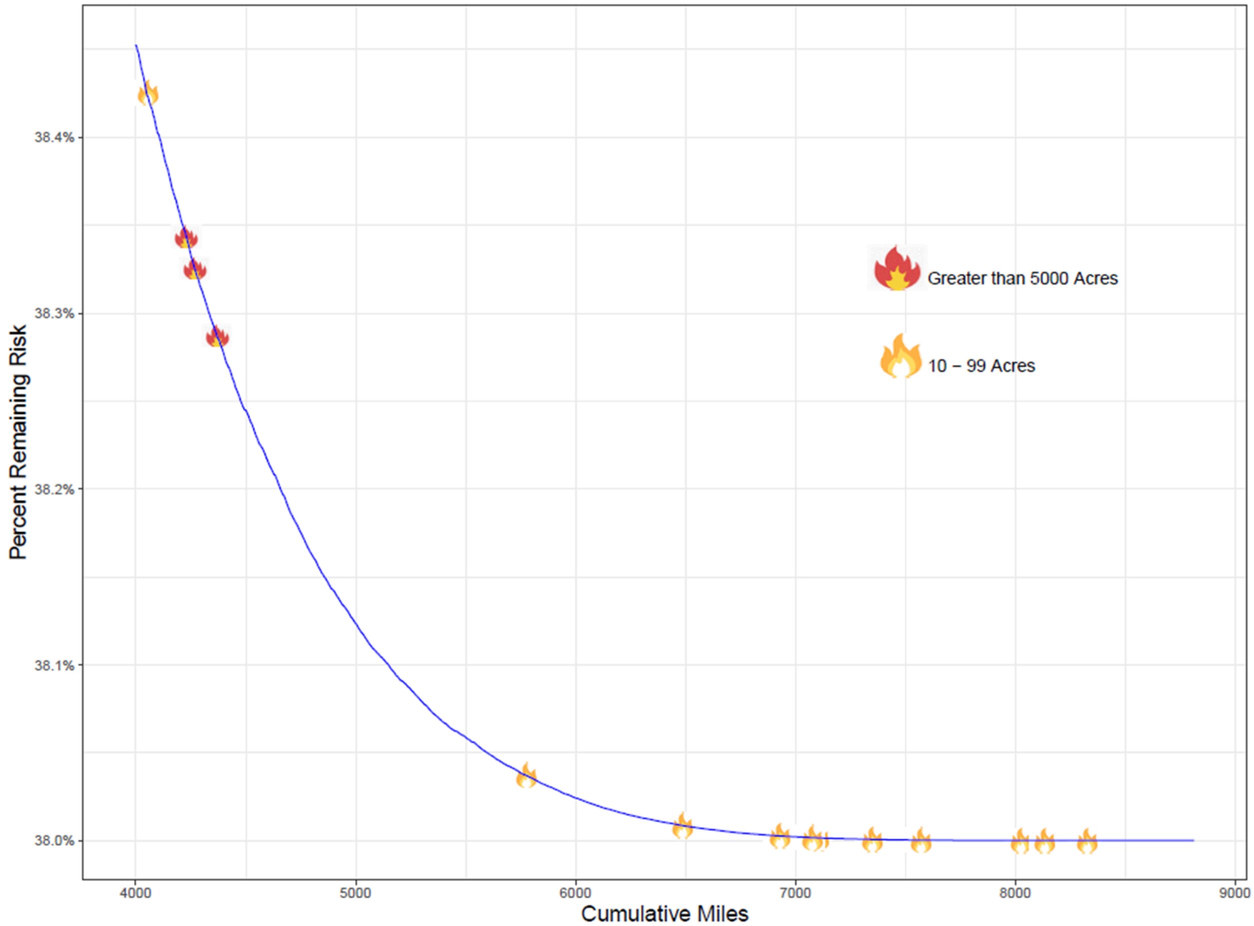
[310] Ex. SCE-47 (Roy), p. 2.

[311] Ex.SCE-12, Vol. 1 (Payne), p. 7:1-5.

[312] D.14-08-032, p. 28.

[313] Ex. SCE-15, Vol. 5 (Roy), Fig. II-3, p. 25.

Ex. SCE-15, Vol. 5: Figure II-3 Overlay of Historical Large Fire Events on SCE's Relative Risk Buydown Curve[314]



As an initial matter, and for purposes of clarification, each fire icon represented in the figure does not necessarily represent a separate fire, each icon instead represents an impacted circuit.[315] Figure II-3 reflects two fires greater than 5,000 acres and seven fires impacting between 10 and 99 acres.

TURN does not contest that nine fires have occurred from 2014-2018 on circuits that appear to be on miles between 4,000 and 9,000 on SCE's risk buydown curve, or that TURN's proposal would not deploy covered conductor on those miles. TURN does contest that it is an

[314] Ex. SCE-15, Vol. 5E3 (Roy), p.25E.

[315] Ex. SCE-15, Vol. 5E3 (Roy), p. A331E.

efficient use of ratepayer dollars consistent with just and reasonable rates to deploy covered conductor to circuits at such relatively low points in the risk buydown curve. TURN fully expects other wildfire risk mitigations to be deployed here, as discussed above. As the y-axis of SCE's Figure II-3 demonstrates, the circuits shown represent between 38 and 38.5 percent of remaining wildfire risk. In other words, TURN does not believe it is just, reasonable, necessary, or efficient to spend $421,000 per circuit mile to potentially buy down less than 0.5% of remaining wildfire risk. SCE's Rebuttal demonstrates the utility has effectively ignored affordability constraints in lieu of arguments that ratepayer funds must be expended subject only to the limits of SCE's resources.

15.2.1 The Commission Should Direct SCE to Study the Interaction of Mitigations and Identify Efficiencies

TURN highlights that, despite the proposed extraordinary expansion of covered conductor, SCE has not identified any potential redundancies that would decrease SCE's spending on other mitigations in the locations where covered conductor is deployed.[316] For example, as stated by TURN witness Borden, "if covered conductor is as effective in mitigating ignitions when vegetation comes into contact with powerlines as SCE believes it will be, the utility should be able to relax more stringent tree trimming requirements."[317] Relaxed tree trimming requirements should result in reduced costs to be passed on to ratepayers, but a corresponding reduction is not evidenced in SCE's budget. While TURN believes that covered conductor should lead to lower costs elsewhere, it has made no adjustments to SCE's budget to

[316] Ex. TURN-02 (Borden), pp. 7:1-8:16.

[317] Ex. TURN-02 (Borden), pp. 8:9-11.

address potential redundancies.[318] Related to the potential for redundancies and the potential for efficiencies, TURN recommends that the Commission direct SCE to study how costs can be reduced for ratepayers while maintaining a consistent level of safety.[319]

15.2.2 Wildfire Mitigation Practices in Australia Demonstrate the Importance of a Diverse Wildfire Mitigation Portfolio.

Other jurisdictions demonstrate the value of relying on a variety of wildfire mitigation practices, as proposed by TURN. SCE frequently points to the success of Australia in its use of covered conductor. According to SCE Witness Roy, "their fault information, which they call 'near misses' have gone down drastically based on all their wildfire mitigation, and covered conductor is a prominent piece of that."[320] Covered conductor, however, is only one among a number of wildfire mitigations utilized by AusNet, and has only been deployed over approximately 345 circuit miles, discussed below. An inexhaustible list of other "prominent programs in the Australian state of Victoria" that are also applicable to SCE include: 1) dampers and armour rods; 2) more frequent line inspections and pole tests; 3) LIDAR assessment of vegetation clearances; 4) conductor spacing survey and remediation; 5) Upgrading of [high voltage] fuses with [ACRs]; 6) Enhanced [ACR] settings; 7) Fuse-savers as [ACRs]; 8) insulated conductors on pole tops; 9) selective covered conductors; 10) selective undergrounding; 11) enhanced vegetation management clearances; 12) hazard tree management; 13) fire loss consequence maps; 14) aerial surveys and image evaluation; 15) earth fault ignition research and development; 16) vegetation fault ignition research; 17) vegetation fault signature research; 18)

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[318] Ex. TURN-02 (Borden), p.8:11-12.

[319] Ex. TURN-02 (Borden), p.8:11-16.

[320] 8 TR 938:22-939:6 (SCE/Roy).

installation of [REFCLs]; 19) development of fire risk models; and 20) the equivalent of Distribution Fault Anticipation (DFA).[321] SCE is proposing many of these programs in its 2021 GRC, or has already invested in such programs.[322] Given the multiple programs relied on by AusNet to reduce wildfire risk, its successes cannot be reduced to any one mitigation. Instead, AusNet is an example of the importance of maintaining a diverse wildfire mitigation portfolio, including but not limited to covered conductor.

Underscoring the success of Australia's suite of mitigations rather than just covered conductor, is that the utility has only installed and only is required to install a portion of the mileage of covered conductor that SCE proposes in this rate case. AusNet was directed by the Victoria Bushfire Royal Commission to replace electrical lines within identified high fire risk areas.[323] "Thirty-three codified areas have been identified by the Government as having the highest fire loss consequence[, and i]t is estimated that, on average, electrical lines in codified areas will be replaced within 25 years."[324] Approximately 1,000 miles of bare wire is within AusNet's territory identified as a "codified area."[325] As of December 2019, 555 km or approximately 345 miles, of AusNet's system was projected to be "replaced with covered conductor or underground lines."[326]

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[321] Ex. SCE-47 (Roy), p.12.

[322] Ex. SCE-47 (Roy), p.12: While TURN's position varies from program to program, it has only made reductions to some of the similar programs proposed by SCE. In the case of DFA, as discussed in Section 15.4 below, simply seeks additional information before customer's bear its costs.

[323] Ex. SCE-15, Vol. 5 (Roy), p. A110.

[324] Ex. SCE-47 (Roy), p. 11.

[325] Ex. SCE-15, Vol. 5 (Roy), p. A111.

[326] Ex. SCE-47 (Roy), p.11.

AusNet may have had success addressing wildfire risk, but AusNet's program does not justify SCE's proposal for an extraordinary expansion of covered conductor. It is not clear to TURN that the successes of AusNet's wildfire mitigation portfolio are solely due to its covered conductor installations to date. While TURN is hopeful that covered conductor is an extremely effective wildfire mitigation, even if covered conductor has been as successful as SCE argues it has in Australia, the scope and pace of its installation in Australia does not support SCE's proposal in this rate case.

15.2.3 Installation of Covered Conductor Will Not Necessarily Result in Reduced PSPS.

SCE highlights that over half of its ignitions over the last five years have been caused by Contact from Objects and Wire-to-Wire contact, and that only three mitigation programs address these drivers: "covered conductor, repeated and increasing use of PSPS, and widespread undergrounding."[327] SCE declines to implement large scale undergrounding because while undergrounding addresses the wildfire ignition drivers it is "financial prohibitive and practically infeasible from a widespread deployment perspective."[328] TURN, however, cautions the Commission from treating SCE's proposal as a choice between ongoing PSPS and covered conductor.

As noted above, SCE will not commit to any reduction in PSPS events for circuits covered conductor has been deployed.[329] Based on SCE's statements, it could in fact be the case that SCE would pursue its full 6,200 miles of covered conductor at a cost of $3.4 billion and still

[327] Ex. SCE-15, Vol. 5 (Roy), p. 29:10-14.
[328] Ex. SCE-15, Vol. 5 (Roy), p. 29:15-16.
[329] Ex. SCE-47 (Roy), p. 7.

pursue PSPS at the same scope and scale resulting in additional harms to its customers already facing considerable affordability limitations.

In the WMP Resolutions, the Commission has found that "[PSPS] while potentially useful in the mitigation of wildfires, results in significant hardship and cost to utility customers."[330] As the Commission notes, when calculating Risk Spend Efficiency (RSE) for PSPS, "electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included."[331] Because of this failure to include societal impacts, the Commission has directed utilities to "not rely on RSE calculations as a tool to justify the use of PSPS."[332] Similarly here, SCE should not be able to rely on PSPS as a reasonable alternative to and justification for covered conductor, especially since the utility cannot preclude that any given circuit won't both have covered conductor deployed and a PSPS event. Since SCE has not committed to reducing PSPS in any way due to deployment of covered conductor, this argument cannot be relied upon by the Commission to justify the scope and pace of SCE's covered conductor proposal.

15.2.4 TURN Recommends Reductions to the Pole Replacement and Tree Attachment Budget

SCE's original budget for pole replacement is based on the size of its covered conductor proposal and for a wholesale replacement of poles with fire resistant composite poles.[333] SCE however, adjusted its proposal for pole replacement in response to TURN's proposal that rather

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[330] WSD-002 (R.18-10-007), pp. 2-3.

[331] WSD-002 (R.18-10-007), p. 20.

[332] WSD-002 (R.18-10-007), p. 20.

[333] Ex. SCE-04, Vol.5 (Roy), p. 28:8-12.

than full replacement using fire resistant composite poles, where feasible the utility should use wood poles and fire resistant wrap. For purposes of its proposed covered conductor program, TURN assumed that 75% of the time fire resistant wrap will be sufficient rather than the more expensive composite pole.[334]

SCE's rebuttal testimony acknowledged that TURN's position had merit but recommended that the covered conductor program budget assume a 60/40 split between pole wrap and full replacement.[335] SCE based its 60/40 split based on the development of a decision tree.[336] SCE's rebuttal testimony, however, does not explain how the decision tree logic better supports its proposed 60/40 split rather than the 75/25 split recommended by TURN. SCE has not run its population of poles through the decision tree yet, and until it does so, the appropriate ratio cannot be determined. SCE suggests that in some cases composite poles may be required given the impact of woodpecker damage: "at locations with…known woodpecker problem areas, SCE will continue to deploy composite polls."[337] The utility, however, admits that it has not reported any fire related to woodpecker damage between 2014 and 2019, and disputes that the Thomas Fire was related to a pole weakened by woodpecker damage.[338] As is the case with SCE's vertical switch program, discussed in Section 15.5.1 below, TURN agrees that damaged equipment should be replaced, but SCE's evidence does not suggest that the wildfire risk reduction is sufficient to justify the added expense of SCE's 60/40 proposal.

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[334] Ex. TURN-02 (Borden), p. 24:7-20.

[335] Ex. SCE-15, Vol. 5 (Roy), p. 34:13-15.

[336] Ex. SCE-15, Vol. 5 (Roy), p. 259.

[337] Ex. SCE-15, Vol. 5 (Roy), p. 34:18-19.

[338] Ex. SCE-47 (Roy), p. 9.

In light of SCE's failure to demonstrate, with specificity, the number of poles that require replacement, TURN recommends that the Commission adopt its 75/25 forecast for pole replacement and direct the utility to track the actual split between pole wrap and fire resistant poles. Further, the Commission should direct the utility to default to pole wrap rather than installation of a fire resistant pole; if the utility demonstrates a different proportion, it can request those costs in the future.

Similarly, SCE's proposed budget for tree attachments is driven by the scope of its covered conductor proposal.[339] As described in its rebuttal testimony this proposal is driven by the operational efficiencies gained by replacing tree attachments at the time covered conductor is installed.[340] As discussed above, TURN's covered conductor proposal would deploy conductor, and replace tree attachments, on the circuits that represent the greatest risk. The circuits that TURN's proposal would address have the highest Reax scores, as "derived from the current…risk prioritization model,"[341] and would address the circuits with the largest average consequences per mile in terms of structures destroyed and acreage burned.[342] Presumably, and without any evidence suggesting otherwise, the other equipment like tree attachments in these high priority circuits would have similar risk scores, so the TURN proposal would address the highest risk tree attachments.

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[339] Ex. SCE-04, Vol. 5 (Roy), p. 21:15-27. SCE states it "plans to replace tree attachments together with covered conductor deployment."

[340] Ex. SCE-15 Vol. 5 (Roy), p. 33:11-12.

[341] Ex. SCE-15, Vol. 5 (Roy), p. 22, Note 50.

[342] Ex. SCE-15, Vol. 5 (Roy), Table II-7, p. 22.

SCE provides no risk information specific to tree attachments that demonstrates that tree attachments outside of the highest risk areas do not see a similar decline in risk score. To the extent that the efficiencies of addressing tree attachments at the same time as covered conductor justifies the cost of remediation, SCE has not demonstrated that, absent these efficiencies, the wholesale replacement and remediation of these tree attachments provides a safety benefit commensurate with its cost and consistent with just and reasonable rates. For areas where covered conductor is not deployed, TURN recommends that the utility replace tree attachments on an ad hoc basis when necessary based on inspection.

15.3 Community Resiliency Incentives

15.4 Distribution Fault Anticipation: Pending the Results of its DFA Pilot SCE has not Justified its Proposal for Full Deployment of DFA.

TURN recommends that the Commission reject SCE's forecast of capital and related O&M for a full deployment of the proposed Distribution Fault Anticipation (DFA) program. Rejection of the DFA program should be without prejudice and pending a subsequent application demonstrating the results of the DFA pilot. The Commission should not create the precedent of funding full roll out of programs before the results of a pilot have been presented.

In rebuttal testimony, SCE states that TURN has misunderstood the purpose of SCE's pilot and concluded that the technology is not promising.[343] On the contrary, TURN's testimony specifically states that the "technology sounds promising," but notes that parties and the Commission have not had a chance to review the results of the pilot.[344] SCE stated in response to discovery that it "is currently evaluating the DFA technology and will be complete with the

[343] Ex. SCE-15, Vol. 5 (Swisher), p. 40:13-21.

[344] Ex. TURN-02 (Borden), p. 8: 21-23.

assessment of its effectiveness by first quarter of 2021."[345] Therefore, TURN understands that complete results from deployment were not available to parties for opening testimony.

TURN's objections are designed to ensure adequate consideration of the pilot results. SCE's rebuttal describes the successes of its program and assures the Commission it would only pursue a worthwhile program.[346] TURN is happy to hear that the pilot, thus far, appears to have confirmed SCE's belief in the technology, but it does not change the fact that the utility has not presented the full results of its pilot program for stakeholder review. The Commission should require the utility to present the full results of its program before providing the program funding; failure to do so obviates the purpose of a pilot. While SCE's pilot may have been to determine "how best to scale up a particular device or technology," until the utility presents the results of that pilot, it cannot demonstrate that the technology scales to its service territory, that it has truly been effective, or that it has properly determined the budget for the program.[347] If the Commission were to approve a full program without demonstration, it would imply that any proposed program can be fully funded without demonstrating the efficacy of the underlying technology or providing data and analysis upfront in utility testimony for stakeholder review.

Further, SCE has not demonstrated that the cost of the full deployment of DFA is just and reasonable. SCE has not demonstrated that the program will result in safety benefits consistent with its cost and does not include any information on the Risk Spend Efficiency of the technology. No Risk Spend Efficiency was provided in the WMP filing, and SCE is directed to include results on its pilots including "quantitative risk reduction benefits" in its quarterly

[345] Ex. TURN-02- Atch-01, p.17.

[346] Ex. SCE-15, Vol. 5 (Swisher), p.40:22-25.

[347] Ex. SCE-15, Vol. 5 (Swisher), p. 40:13-14.

report.[348] Failure to address the potential benefits of not only the pilot, but of a full roll out of the technology leaves SCE unable to demonstrate that the program provides its customer safety benefits commensurate with the cost of the program.

15.5 Enhanced Overhead Inspections and Remediations

15.5.1 Vertical Switches: SCE has not Demonstrated that Wholesale Replacement of Vertical Switches is a Just and Reasonable Use of Ratepayer Dollars.

SCE proposes to replace all vertical switches in its HFRA, regardless of whether the switch currently poses an ignition risk based on the most recent inspection. SCE, however, has not demonstrated that such replacement is just and reasonable and justified by the associated safety improvement. SCE acknowledges that it has not presented any evidence that a vertical switch has caused an ignition but argues that it could happen in the future.[349] Similarly, SCE's Testimony includes no information on the risk reduction potential of the wholesale vertical switch replacement. General Order 95, specifically, requires that electric facilities be "inspected frequently and thoroughly for purposes of ensuring that they are in good condition."[350] Like other equipment, these vertical switches should be regularly inspected, and, if and when a problem is detected, the utility should fix or replace the vertical switch.[351]

In the absence of an engineering justification for its proposal by SCE, TURN Witness Borden solicited input from Dennis Stephens, "a utility distribution engineer with Xcel Energy in

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[348] See WSD-004, p. 27: "SCE only calculated an RSE for a fraction of its initiatives." WSD-002, p. 28.

[349] Ex. SCE-15, Vol. 5 (Swisher), p. 51:8-10.

[350] CPUC General Order 95, Rule 31.2, Rule 52.2 applicable to crossarms states to see Rules 31.1 and 31.2.

[351] 11 TR. 1167: 13-19 (Stephens).

Colorado for over 30 years" on the risk reduction potential of SCE's proposal.[352] According to Mr. Stephens, "there is no engineering basis for finding that replacement of vertical switches provides an ignition reduction benefit."[353] Mr. Stephens testified that he has not often seen the problem that SCE's vertical switch program is designed to prevent.[354] Similarly, Mr. Stephens did not see other examples of the problem in materials supplied by SCE.[355]

SCE highlights that "[i]n 2019 alone, SCE identified 45 vertical switches out of a population of 190 in HFRA that presented ignition risk concerns."[356] Even with almost a quarter of vertical switches requiring repair or replacement, Mr. Stephens testified it is not appropriate to pursue wholesale replacement unless it was demonstrated to be the most efficient means of addressing the potential problem.[357] Regular inspections, as required by General Order 95, should not only reveal any vertical switches that require repair or replacement, but provide an opportunity to address any misalignments or other circumstances before the problem becomes more serious.[358] TURN does not oppose replacing or repairing vertical switches that are likely to fail as part of the utility's overhead inspection and remediation programs.

[352] Ex. TURN-02 (Borden), p.10, Note 26.

[353] Ex. TURN-02 (Borden), p. 10:11-12.

[354] 11 TR 1170:15-20 (Stephens).

[355] 11 TR 1170:27-1171:3 (Stephens).

[356] Ex. SCE-15, Vol. 5A (Swisher), p. 52:4-6.

[357] 11 TR 1174:3-8 (Stephens).

[358] 11 TR 1175:5-15 (Stephens).

While TURN agrees that there is a potential for arcing, albeit low,[359] it does not follow that the potential for arcing justifies wholesale replacement of vertical switches. SCE has not demonstrated that the potential for arcing presents a safety risk sufficient to justify the cost of the program, highlighted by the fact that the utility cannot point to any ignitions caused by vertical switches.[360] TURN recommends that the Commission reject SCE's forecast for vertical switches, directing instead that the utility continue to remediate any equipment problems as they arise.[361]

15.6 Enhanced Situational Awareness

15.7 Fire Science and Advanced Modeling

15.8 Fusing Mitigation

15.9 Organizational Support

15.10 Other Issues- Retirement of Prematurely Replaced Assets

In the course of SCE's covered conductor program, the utility will replace assets that are in service; in some cases, the replacement will be of assets that were installed relatively recently. Given the already steep rate implications of SCE's wildfire mitigation capital investments, the Commission should take reasonable steps to protect ratepayers from paying "for two pieces of equipment even though only one is installed."[362] TURN witness Borden recommends that where, in the course of its covered conductor program, SCE's replaces an asset that was installed

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[359] 11 TR 1172:12-16 (Stephens): "[Q] from your engineering basis, isn't possible for arcing to occur when the contacts are not seated properly? A: Yes, that's correct, there is a possibility. I'm just saying its very low."

[360] Ex. SCE-15, Vol. 5 (Swisher), p. 51:8-10.

[361] Ex. TURN-02 (Borden), p. 10:12-13.

[362] Ex. TURN-02 (Borden), p. 26:16-18.

less than 5 years earlier, either the remaining net recorded plant amount for that asset be removed from ratebase or, at a minimum, the associated return be set no higher than the cost of debt, preventing SCE from profiting from the early retirement.[363] TURN further recommended that these assets be tracked and reported annually.[364] TURN identified five years as the time that SCE should have been aware of the need for improved wildfire risk mitigation tactics.[365]

In rebuttal testimony, SCE recommends TURN's proposal be rejected, arguing that these assets are in fact facing near term failure, early retirements are a part of ratemaking and there is no imprudence.[366] The full cost and rate impact of this proposal is unknown at this time, due to the exact number of prematurely retired assets having not yet been identified.[367]

The Commission should further mitigate the impact on ratepayers from SCE's covered conductor proposal, in recognition that it is the sheer size of SCE's covered conductor proposal that drives the financial impact of these early retirements. As SCE notes, the TURN proposals for the treatment of prematurely replaced assets only applies to a subset of the assets that would be replaced as a part of SCE's program.[368] As TURN witness Borden points out, in its most recent rate case PG&E proposed the installation of covered conductor in only 7% of its system

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[363] Ex. TURN-02 (Borden), p. 27:6-10, 24-28.

[364] Ex. TURN-02 (Borden), p. 27:21-23.

[365] Ex. TURN-02 (Borden), p. 27:6-12: "TURN's primary recommendation is to remove from ratebase the net recorded plant amount for assets installed less than 5 years from when SCE replaces the asset. This will, for example, prevent ratepayers from paying for two poles where only one is in service, when that circumstance is due to the utility's relatively late epiphany that its previous wildfire risk mitigation investments and strategies were inadequate."

[366] Ex. SCE-18, Vol. 2 (Varvis), p. 10:1-2, 11:7-9, 12:12-13.

[367] Ex. SCE-54 at 76.

[368] Ex. SCE-18, Vol. 2 (Varvis), p.12:24-26.

within HFRA.[369] In comparison, SCE's proposal would install covered conductor in 60% of its HFRA;[370] TURN's more modest proposal would still extend covered conductor (and the potential for prematurely replaced assets) to 25% of SCE's HFRA.[371] The magnitude of SCE's proposal not only results in significant direct impacts from funding the costs of installing the covered conductor, but also the highest amount of prematurely-retired assets that, but for the covered conductor program, would remain in service for some time.

SCE argues that early retirement is "normal, expected, and already assumed in the average service lives."[372] SCE continues, "[a]uthorized depreciation expense is calculated with the understanding that unrecovered depreciation expense due to early retirement is 'made up' by depreciation expense on the other units that outlive the average service life of an account."[373] But this logic applies most clearly to early retirement tied to factors not under the utility's control, such as "car hits pole" or a municipality pursuing a street widening that requires removal of existing utility facilities. Here, SCE is potentially replacing substantial amounts of conductor and poles that is still within its useful life in 60% of its HFRA and is doing so only due to a new utility program. And as TURN witness Borden warned, under SCE's approach ratepayers will be left paying the depreciation expense on two assets, even where the replaced asset was very recently installed. TURN's proposal merely seeks to protect ratepayers from this added expense for at least those assets installed in the last five years.

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[369] Ex.TURN-02 (Borden), p. 5:9-10.

[370] Ex. SCE-04, Vol. 5 (Roy), p. 25:4-6.

[371] Ex. TURN-02 (Borden), p. 5:5-7.

[372] Ex.SCE-18, Vol. 2 (Varvis), p. 11:7-9.

[373] Ex. SCE-18, Vol. 2 (Varvis), p. 11:12-15.

SCE argues that FERC guidance allows utilities to replace assets, despite their relatively young age, in cases of inadequacy, and that the threat of wildfires leaves its existing conductor inadequate and requires additional mitigation.[374] But this logic presumes the only reasonable option for additional mitigation is installation of covered conductor to replace existing conductor. As TURN demonstrated above, covered conductor is not 100% effective at preventing wildfire, and effective wildfire mitigation relies on a variety of mitigation efforts. If SCE had in fact narrowly targeted its covered conductor program at the highest risk circuits, it could argue that the program sought to address an inadequacy in its system. But the inclusion of many lower risk circuits and the reliance of multiple mitigations in every location undermines any argument regarding adequacy as a reason to fully fund two assets where only one is in service.

Finally, SCE states that there is no imprudence alleged in regard to the assets to be replaced. But in prior decisions, the Commission has removed assets from rate base or adopted a reduced return on the remaining plant amount associated with those assets where the assets are removed from service before the end of their useful life. For example, the Commission adopted a reduced rate of return for all of the rate base associated with electromechanical meters replaced by automated metering infrastructure (AMI, aka "Smart Meters"), even though there were no allegations of imprudence in the move to AMI.[375] In D.11-05-018, the Commission found that

[374] Ex. SCE-18, Vol. 2 (Varvis), p. 11:21-25.

[375] D.11-05-018 (PG&E test year 2011 GRC), pp. 60-63. D.11-05-018 includes a discussion of relevant precedent on pp. 42-48; *see also* D.85-12-018 (shared the burden of costs related to power plants that were no longer economical or used and useful between shareholders and ratepayers); D.85-08-046 (allowed shareholders to recover investment on prematurely retired assets but did not allow return on undepreciated plant); D.92-12-057 (Remaining net plant costs amortized over four years with no return on balance for prematurely retired asset).

even through the smart meters were cost efficient, as to the replaced meters, "it would be poor public policy to not minimize the costs to ratepayers to the extent possible, because ratepayers are no longer getting any use of that plant."[376]

Where, as here, the amount of recently-installed assets that would be removed from service due to a change in utility policy and practice is directly influenced by the proposed scale for the new practice (reliance on covered conductor), the Commission should protect SCE's customers from the adverse rate impacts resulting from the early retirement of assets. To the extent that prematurely retired assets are no longer used and useful because they were replaced by a new program, and especially where the new program's cost-effectiveness is not clearly established, it is inequitable for shareholders to benefit by continuing to collect the full return on both the replaced and the replacement assets, at the expense of SCE's ratepayers.

16. T&D OTHER COSTS AND OTHER OPERATING REVENUE

17. CUSTOMER INTERACTIONS

17.1 Overview

TURN Recommends a reduction of $25.560 million O&M and a reduction of $5.193 million capital expense for Customer Interactions, summarized in the following tables:

[376] D.11-05-018 (PG&E test year 2011 GRC), p. 67.

Customer Interactions Summary (O&M Constant 2018 $000)

	Reduction
Billing and Payments O&M	($6,468)
Communications, Education & Outreach O&M	($6,247)
Customer Contacts O&M	($6,026)
Customer Care Services O&M	($5,834)
Service Guarantee Program	($985)
Total O&M Reduction	**($25,560)**

Customer Interactions Summary (Capital Constant 2018 $000)

	Reduction
Customer Contact Center Capital	($5,193)
Total Capital Reduction	**($5,193)**

17.2 Billing & Payments

17.2.1 Billing Services

TURN recommends a reduction of $6.468 million for Billing and Payments, summarized as follows:

Billing and Payments Summary (O&M Constant 2018 $000)

	Reduction
Billing Exceptions -- Bundled Accounts	($1,878)
Billing Exceptions -- CCA Accounts	($2,843)
Policy Adjustments	($242)
Credit & Payment Processing (Labor)	($637)
Credit & Payment Processing (Non-Labor)	($668)
Rural Offices Closures	($200)
Total Billing and Payments Reduction	**($6,468)**
Uncollectible Expenses	**0%**

17.2.1.1 SCE's Request for Incremental Billing Funding Is Unjustified and Contrary to Evidence

SCE requests an increase of $1.878 million to manage billing exceptions for bundled accounts and $2.843 million for CCA Accounts.[377] SCE asserts that the increase is necessary because the volume and complexity of exceptions has been growing due to the increase in Net Energy Billing ("NEM"), CCA Growth, and others.[378] However, a closer look reveals that SCE's claim that increases in NEM and CCA customers is leading to increases in billing exceptions and therefore requires additional funding is unsupported and contrary to evidence.

SCE asserts that the number of billing exceptions has grown dramatically from 2017 to 2018, increasing from 2.155 million to 2.909 million.[379] However, an examination of the data shows that virtually all of the increases in billing exceptions resulted from increases in Edison SmartConnect ("ESC") usage exceptions, which accounted for 97% of the increase.[380] This is significant because ESC usage exceptions are *meter data* exceptions, which are exceptions that results when "SCE's automated process finds missing, incomplete, or abnormal energy usage data during the billing process."[381] Since the smart meter is the same whether a customer is a bundled, NEM, or CCA customer, there is no reason for the growth in these accounts to generate higher meter usage data exceptions. Second, also seen from the historical figures, past growth in NEM and CCA accounts did not necessarily result in higher usage exceptions. For example, from 2015 to 2016, both NEM and CCA exceptions grew, yet the ESC usage exceptions

[377] Ex. SCE-03 V01A, p. 20.
[378] *Id.*
[379] Ex. SCE-03 V01A, p. 13.
[380] *Id.*
[381] Ex. SCE-14, p. 11.

decreased drastically from 2015 to 2016.[382] Furthermore, it is evident from the historical exceptions that the growth of NEM and CCA customers could not have possibly contributed to the level of growth in usage exceptions. While NEM exceptions grew from 157 in 2017 to 176 in 2019, usage exceptions grew from 547 in 2017 to 1,235 in 2019. Clearly, the growth in usage exceptions is due to other issues and not due to the growth of NEM and CCA customers.

In its rebuttal, SCE attempts to obscure the issue by suggesting that NEM, TOU, and CCA customers require more interval data calculations, stating that "NEM 2.0, TOU and CCA customer bills require calculations based on Over The Air ("OTA") reads for approximately 2,880 intervals per month. This additional complexity is in stark contrast to standard domestic tiered rate customer accounts, where interval data is not required for customer bill calculations."[383] Yet, when pressed by TURN in a subsequent data request, SCE concedes that a "CCA customer on a tiered rate does not require more interval calculations than an SCE customer on a tiered rate."[384] SCE further concedes that "it collects and processes interval data for customers on tiered rates" just as it does for customers on TOU or NEM rates because SCE's billing system checks the interval data collected against a set of predefined data validations to ensure accuracy and completeness of the data, as well as provides hourly usage charts on sce.com and data for the Budget Assistant program and the Rate Analyzer tool.[385] Hence, NEM,

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[382] Ex. TURN-06 Atch 1, DR TURN-SCE-060, Question 4. SCE claims that growth in NEM and CCA customers leads to higher NEM and CCA exceptions, so it is reasonable to use NEM and CCA exceptions to test the theory of whether the growth in these customers led to growth in usage exceptions.

[383] Ex. SCE-14, p. 11.

[384] Ex. TURN-70, DR TURN-SCE-086, Question 3.

[385] Ex. TURN-70, DR TURN-SCE-086, Question 4.

TOU, and CCA customers categorically *do not* need more interval data and associated calculations. The evidence clearly indicates that the growth in usage exceptions is not due to the growth of NEM and CCA customers, but rather data and system issues SCE is experiencing. Therefore, the solution to SCE's data and system issues is *not* additional funding for more FTEs.

Furthermore, TURN reviewed the historical number of customers on complex rates that require manual billing and found that SCE expects to perform an average of 2,635 manual billings per month in 2021, yet it performed an average of 4,533 per month in 2018, a *42% decrease* in manual billings![386] This is further evidence that SCE does not need additional FTEs for Billing. As Public Advocates Office also points out, SCE's Billing FTE was highest in 2016, with both 2017 and 2018 having fewer FTEs.[387]

Given all of the above, SCE does not need an increase in FTEs for Billing. TURN recommends a reduction of $1.878 million for bundled accounts and a reduction of $2.843 million for CCA Accounts, totaling $4.721 million.

17.2.1.2 SCE's Repeated Arguments for Policy Adjustments Funding Should Be Rejected Again

SCE requests $242,000 for Policy Adjustments despite the Commission's clear direction to the contrary on this issue in its recent 2018 GRC decision. SCE's testimony misleadingly claims that in the 2018 GRC, the Commission used TURN's proposed removal of one specific cost as a basis to disallow the entirety of the forecast.[388] What the Commission actually stated

[386] Ex. TURN-06 Atch 1, DR TURN-SCE-060, Question 3.

[387] Ex. PAO-08P, p. 10.

[388] Ex. SCE-03 V01, pp. 20-21.

was that "SCE has not established that ratepayers should pay for its errors" and therefore the Commission did not authorize any amount for policy adjustments.[389] Yet, SCE again fails to explain why ratepayers should pay for SCE's errors in this Application. In fact, SCE does not even attempt to provide a justification in its direct testimony, nor did it do so in its rebuttal.[390]

Hence, the Commission should once again determine that ratepayers should not pay for SCE's errors and reduce SCE's forecast by $242,000.

17.2.1.3 TURN Withdraws Its Previous Proposed Reduction of $0.5 million for Process Oversight and Support

TURN previously recommended a reduction of $0.5 million for Process Oversight and Support because when SCE amended its Billing and Payments testimony on February 20, 2020 to remove costs relating to Customer Service Re-Platform Project ("CSRP"), it failed to make any adjustments to remove costs to serve as business/operational leads for CSRP.[391] SCE has since clarified that these resources charged their time to the CSRP project and that their labor costs were not included (either before the amendment removing CSRP from this proceeding or after) in recorded 2018 and 2021 forecast. Thus, TURN withdraws its previous reduction of $0.5 million for Process Oversight and Support.

17.2.2 Postage Expense

TURN is not addressing this issue in its opening brief but reserves the right to respond to other parties in TURN's reply brief.

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[389] D.19-05-020, p. 134.

[390] Ex. SCE-14, p. 14.

[391] Ex. TURN-06, pp. 4-5.

17.2.3 Credit and Payment Services

17.2.3.1 SCE's Proposed Increase for Credit & Payment Processing Is Unreasonable and Belied by Its Own Data

SCE forecasts an increase of $637,000 in labor expense to support the Credit and Payment Services activities, claiming that the forecast is driven by an increase in Average Handle Time ("AHT") and volume of work.[392] TURN asked for documentations that support SCE's claim of increase in AHT and volume of work and discovered that SCE's "support" for its forecast provided no justification and also mistakenly calculated the growth. Per SCE's workpapers, work volume is only increasing from 686,142 in 2018 to 701,278, which is a 2.2% increase, not a 16% increase as SCE claimed.[393]

In its rebuttal, SCE claims that the 16% increase is based on using its newly invented Incoming Work Volume instead of using recorded Completed Work Volume as a basis of forecasting costs; SCE also claims that this newly invented methodology is "different but more accurate."[394] The difference between the two numbers can only be explained by two possible reasons – either SCE has not been performing adequate Credit and Payment Services to customers, or the Incoming Work Volume that has not been completed each year did not need to be completed to provide adequate service. Since SCE has not acknowledged that it has been providing inadequate service to customers, the most reasonable explanation is that some of the Incoming Work Volume indeed did not need to be completed, for one reason or another, and

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[392] Ex. SCE-03 V01, p. 45.

[393] Ex. TURN-06, p. 8, citing DR TURN-SCE-060, Question 8 Spreadsheet.

[394] Ex. SCE-14, p. 17.

hence it is inappropriate to use forecasted Incoming Work Volume as a basis for necessary resources.

In addition, labor costs for Credit and Payment Services have been declining from $10.9 million in 2014 to $8.5 million in 2018.[395] This is a natural result of increasing electronic payments (and associated decrease in mail-in and in-person payments) which likely contributed to the decline in the average cost per payment. In 2014, there were 30,612 electronic payments, which grew to 37,599 in 2019. By contrast, in 2014, mail-in payments and in-person payments totaled 18,038, but by 2019 the total decreased to 12,259.[396] Similarly, the average cost per payment has been decreasing *every single year*, starting at $0.34 in 2014 and ending in $0.25 in 2019.[397] It is worth noting that SCE forecasted 2019 expenses to be $14.5 million, which would have increased the average cost per payment from $0.27 to $0.29. Yet, the recorded cost for 2019 was $12.7 million, which resulted in a decrease of average cost from $0.27 to $0.25.[398] Despite this compelling evidence of decreasing costs, SCE continues to make the unreasonable and unsupported forecast that its average cost per payment will *increase by 16%* from 2019 to 2020.

Given the undisputable facts that the mix of electronic payments has been increasing since 2014 and average cost per payment has been steadily decreasing every year since 2014, the Commission should reject SCE's unsupported and unreasonable request to increase the labor

[395] Ex. SCE-03 V01, p. 43.

[396] Ex. TURN-06, p. 9, citing DR TURN-SCE-060, Question 10.

[397] Ex. TURN-06, p. 9, citing DR TURN-SCE-060, Question 11.

[398] *Id.*

expense by 7.5%. TURN recommends using base year recorded as the expense, which results in a reduction of $637,000.

17.2.3.1 SCE Agreed to Reduce Its Credit and Payment Services Forecast to Account for the Rural Office Closures and the Error for CheckFreePay Services

In its rebuttal testimony, SCE agreed with TURN and Cal Advocates that its forecast should be reduced by $200,000 to account for the closure of the Rural Offices. SCE further agreed to correct an error with regards to CheckFreePay services and reduce its forecast by $0.668 million. TURN supports both revisions.

17.2.4 Uncollectible Expenses

SCE originally requested an uncollectible expense rate of 0.191%, which includes an adjustment of 0.017% for Disconnection OIR (D.18-12-013).[399] TURN's direct testimony demonstrated that the adjustment of 0.017% is unrealistic and overexaggerated estimate, particularly when SCE's own workpapers show that only about 3% of customers that were eligible for disconnection were not disconnected on the extreme weather days,[400] but these customers were eligible for disconnection once the extreme weather condition ended. TURN recommended an adjustment of 0.001%, resulting in a final uncollectible rate (or uncollectible expense factor) of 0.175%.[401]

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[399] Ex. SCE-03 V01, pp. 55-56.

[400] Ex. TURN-06, p. 10, citing DR TURN-SCE-060, Question 17.

[401] Ex. TURN-06, pp. 10-11.

However, through discovery conducted by TURN, SCE later identified an error in its analysis and updated its uncollectible forecast to 0.180%.[402] Upon review of SCE's updated analysis, TURN agrees with SCE and supports SCE's updated uncollectible rate of 0.180%.

17.3 Communications, Education & Outreach

17.3.1 Customer Communications, Education, and Outreach

Communications, Education & Outreach Summary
(O&M Constant 2018 $000)

	Reduction
Analytics & Integrated Marketing	($5,200)
Education and Awareness	($1,047)
Total Communications, Education & Outreach O&M Reduction	**($6,247)**

Analytics & Integrated Marketing

SCE requests an increase of $5.2 million in non-labor O&M costs for its Analytics & Integrated Marketing ("AIM") effort. SCE's request should be rejected because the project is not cost effective, and SCE has not demonstrated how the effort would provide tangible benefits to ratepayers. SCE also does not identify any cost reductions for its existing analytics and marketing labor costs as a result of spending an extra $5.2 million a year to buy additional capability.

As noted earlier, now is not the time for SCE to engage in unnecessary spending that further burdens the many Californians that are already struggling to afford their energy bills. Not only is the AIM effort unnecessary, even SCE's own analysis shows that it is not cost effective. SCE estimates that the effort would generate average savings of $3.343 million a year, yet the

[402] Ex. SCE-14E2, pp. 20-23.

effort costs $5.2 million a year, which is clearly not cost effective.[403] In addition, SCE just added four positions to its Customer Communications, Education and Outreach ("CCE&O") team, consisting of one Senior Manager of Marketing, one Senior Advisor of Marketing Program Management, one Advisor of Marketing, and one Specialist.[404] SCE does not need to spend another $5.2 million a year on an effort that is not cost effective and is not a required safety or compliance activity.

Furthermore, SCE has not demonstrated that the AIM effort would provide tangible benefits to ratepayers. AIM's benefits seem to primarily focus on the ability to shift customer interactions to lower-cost digital channels and "result in lower operating costs."[405] As noted earlier, since the effort is not cost effective, it does not appear that shifting customers to "lower-cost digital channels" in and of itself provides any tangible benefits to ratepayers.

Lastly, SCE states that the skillsets needed for this effort are not currently found in SCE's in-house labor pool.[406] Yet, it appears to be content with spending ratepayer dollars to have a vendor perform the tasks without an end date. SCE does not outline a plan to develop the necessary skillsets for its in-house labor pool, nor does SCE identify internal labor costs that should be reduced as a result of spending additional ratepayer funds each year to procure outside skillsets.

In its rebuttal, SCE claims that the cost benefit analysis contained in its workpapers only addressed short-term benefits, and it introduced a new cost benefit analysis, for the first time, in

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[403] Ex. SCE-03 V02, p. 23.

[404] Ex. TURN-06, p. 12, citing DR TURN-SCE-065, Question 4.

[405] Ex. SCE-03 V02, p. 22.

[406] Ex. SCE-03 V02, p. 23.

its rebuttal testimony. The new analysis purports to show that there is a 1.19 benefit-to-cost ratio and a $4.6 million net present value of benefits.[407] SCE also erroneously claims that TURN ignored these long-term benefits when evaluating the program, since this long-term benefit analysis did not exist anywhere in SCE's workpapers or responses to TURN's data requests. SCE's new cost benefit analysis is not credible for the following reasons: 1) The fact that it was not included in the original cost benefit analysis suggests that the new analysis was created later in an attempt to justify the project. 2) According to SCE, the first time that this new analysis was provided to any party in this proceeding was January 29, 2020, long after the original analysis was published.[408] 3) When determining the net present value of a project, it is common and best business practice to include future benefits in order to calculate an accurate net present value of a project. It is unlikely that a project would be presented to senior management for approval without including all the identified benefits. This makes SCE's assertion that there are long-term benefits that were not included in its original analysis questionable and unconvincing. The Commission should reject SCE's late attempt to introduce a new drastically different cost benefit analysis that is not credible due to the circumstances explained above.

For the above reasons, TURN recommends a disallowance of the entire $5.2 million for this program.

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[407] Ex. SCE-14, p. 29.

[408] Ex. SCE-14, pp. 29, A-27.

Education and Awareness of CPP Steady State and Building Electrification

SCE requests an increase of $1.047 million to provide education and communication to business service accounts and mass media buys for increasing awareness for building electrification.[409]

SCE's requested increase for education and communication to business service accounts should be rejected because it is not reasonable to spend more money on education and communication *after* defaulting customers to Critical Peak Pricing ("CPP") than *before* or *during* the mass transition. In 2019, SCE defaulted close to 280,000 business service accounts to CPP.[410] Prior to and during the mass transition, SCE necessarily had to engage in numerous education and outreach efforts to ensure that customers were aware of the upcoming transition. Yet, SCE claims that with an expected growth rate in CPP customers of 10% a year (approximately 28,000),[411] it is requesting more funds than it recorded to educate and outreach to 280,000 customers about the mass transition! This is nonsensible and unreasonable and should be rejected.

Furthermore, SCE requests $787,000 for mass media buys to educate customers about building electrification.[412] SCE does not explain why it is not able to use existing authorized marketing expense to perform this function. Surely this is not the first time that SCE has engaged in mass media buys. Unless SCE believes that each time it engages in media buys, it needs to perpetually engage in the same media buys forever (which would be unreasonable),

[409] Ex. SCE-14, p. 35-36.

[410] Ex. SCE-03 V02, p. 24; Ex. TURN-06, p. 13, citing DR TURN-SCE-065, Question 2.

[411] Ex. SCE-03 V02, p. 24.

[412] Ex. SCE-14, p. 36; Ex. SCE-03 V02 WP, p. 12.

there is no reason why SCE needs to increase expenses for media buy instead of shifting existing media buys to communicate a new message. Again, now is not the time for utilities to engage in unnecessary spending that further burdens the many Californians that are already struggling to afford their energy bills.

In its rebuttal, SCE inexplicably tries to argue that it is *not* seeking to spend more than it spent during the mass transition in 2018 or the year after the mass transition (2019). It seems to agree with TURN's previous point that it should not be spending more to perform outreach to 28,000 than it did to perform outreach to 280,000 customers. Yet, it continues to request an *increase* in funding compared to the amount authorized in the previous GRC. Furthermore, SCE attempts to argue that it also needs an increase in funding for media buys because the existing authorized mass media campaigns are still needed, including Operational/Mandated Communications, Rate Communications, Paperless Billing/Self-Service, Summer Campaign.[413] Yet, SCE admits that mass media campaigns do not need to run in perpetuity, and then contradicts itself by providing an example of a campaign that is no longer running (Summer Campaigns),[414] which is one of the campaigns that it claims is still needed in its rebuttal testimony! Clearly, SCE has not supported a need to further increase its funding for media buys because it is able to shift existing media buys to new campaigns.

Thus, the Commission should reject SCE's requested increase and reduce its forecast by $1.047 million.

[413] Ex. SCE-14, p. 36.

[414] Ex. TURN-47, DR TURN-SCE-086, Question 10.

17.3.2 Escalated Complaints and Outreach

TURN is not addressing this issue in its opening brief but reserves the right to respond to other parties in TURN's reply brief.

17.4 Customer Service Re-Platform

Since SCE removed the costs for Customer Service Re-Platform ("CSRP") from this GRC, TURN is not addressing this issue here.

17.5 Customer Contacts

17.5.1 Business Account Management

SCE requests an increase of $5.161 million labor O&M costs for Business Account Management. SCE claims that the increase is necessary because its customers "are requiring more account manager resources and time to support emerging programs and technologies" and because of a shift in focus away from Energy Efficiency ("EE") programs.[415] SCE's claims are unsupported and should be rejected.

First, there has always been and will always be "emerging technologies" that continue to evolve and advance. SCE does not provide any justification for why emerging technologies today require more account manager resources than emerging technologies three years ago. Furthermore, projects for Distributed Energy Resources have actually been slowing down. In 2018, 337 GWh of Distributed Generation was added, which slowed to 262 GWh in 2019 and is projected to be only 159 GWh in 2020.[416] Yet, without providing any justification (even though specifically requested by TURN), SCE forecasts a large unexplained increase in 2021 to 340

[415] Ex. SCE-03 V04, p. 38.

[416] Ex. TURN-06, p. 15, citing DR TURN-SCE-066, Question 2.

GWh (a year-over-year increase of 114%).[417] Similarly, Energy Storage is projected to decrease by 46% from 2019 to 2020, yet SCE forecasts an increase from 2020 to 2021.[418] The Commission should reject SCE's unsupported claims and forecasts.

Second, SCE claims that "customer costs and rates will not be impacted by this Test Year adjustment" because it plans to seek a reduction for the same amount as part of the EE Annual Budget Advice Letter process.[419] The Commission should reject this reasoning because GRC funding should not be increased because SCE plans to reduce spending in EE. SCE also does not explain how its reduced need for EE funding coincidentally *matches exactly* with the increased funding it needs for account manager resources. Ratepayers also should not simply take SCE's word that it will seek the reduction later.

In its rebuttal, SCE repeatedly argues that its requested increase is justified because of the anticipated customer interest growth in Transportation Electrification ("TE"), and how there was a 360 percent increase in TE-related account manager interactions in 2019.[420] SCE's argument is contradicted by the undisputed fact that despite the growth in TE-related increases, activities in other areas have declined, and therefore no additional resources are necessary. In fact, SCE concedes to this fact, noting that "[g]iven the growth in demand for TE-related support in 2019, SCE acknowledges that Business Account management interactions for customer care, grid resiliency and distributed energy resources declined in 2019 compared to 2018."[421] SCE had

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[417] *Id.*

[418] *Id.*

[419] Ex. SCE-03 V04, p. 38.

[420] Ex. SCE-14, pp. 48-49.

[421] Ex. SCE-14, p. 52.

long anticipated the flattening of commercial grid sales and previously forecasted, before the pandemic, that sales for the commercial class would remain flat from 2019 to 2020.[422] In this application, SCE again forecasted, even before the pandemic, that sales for the commercial class would decrease by 1.3% between 2018 to 2023.[423] With the pandemic, commercial sales and related account manager interactions are likely to be significantly lower than previous levels. Adding resources when overall activities are flattening or declining is unreasonable and not justifiable.

For the above reasons, TURN recommends a reduction of $5.161 million.

17.5.2 Digital Operations and Management

SCE requests an increase of $865,000 non-labor O&M expense to support evolving digital channels and optimize digital customer experience.[424] SCE's request is unsupported and should be rejected.

By every possible measure, SCE's digital operations and management has greatly improved customer engagement, which SCE agrees with, stating that "overall customer engagement with SCE's digital offerings has increased significantly in the past five years."[425] All reliable metrics,[426] including SCE.com visits, service requests, electronic bills delivered, payment transactions, report on outage, and % of bills delivered electronically, have grown

[422] A.17-06-030, Ex. SCE-02, p. 74.

[423] Ex. SCE-07 V01 A2, p. 77.

[424] Ex. SCE-03 V04, p. 51.

[425] Ex. SCE-03 V04, p. 46.

[426] Ex. TURN-06, p. 16, citing DR TURN-SCE-066, Question 4. SCE notes that Energy Usage visits, Outage Center page views, and Password Reset figures are unreliable or incomplete.

substantially from 2014 to 2019.[427] For example, Service Requests increased from 199,081 to 336,952, and electronic bills delivered increased from 12.5 million to 26.2 million.[428] Clearly, SCE's investments have been successful, and there is no indication that a higher level of funding is necessary. The current funding level is working well, and SCE does not provide justification for why it is not able to perform any needed improvements using the current non-labor funding level of $1.737 million.

In its rebuttal, SCE claims that "the increase requested for non-labor expenses is necessary and primarily driven by ongoing updates, enhancements, and stabilization of SCE.com and related support of evolving digital channels."[429] SCE does not explain why it cannot use its previously authorized level of funding to provide ongoing updates and enhancements, as if its funding level is zero and that additional funding is needed to perform this fundamental work. A continued annual funding for digital operations and management *is exactly for* activities like updates, enhancements, and stabilization. These activities do not require *increased* funding, which SCE again failed to support in its rebuttal.

For the above reasons, TURN recommends a reduction of $865,000.

17.5.3 Customer Contact Center Capital

In its rebuttal testimony, SCE for the first time seeks authorization for $5.193 million of capital expenses to upgrade its Interactive Voice Response ("IVR") platform, claiming that "the costs of this capital project were inadvertently not included in SCE's direct testimony."[430] As the

[427] Ex. TURN-06, p. 16, citing DR TURN-SCE-066, Question 4.

[428] Ex. TURN-06, p. 16, citing DR TURN-SCE-066, Question 4.

[429] Ex. SCE-14, pp. 55-56.

[430] Ex. SCE-14, p. 56.

applicant, SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application *in its direct testimony*.[431] The Commission has repeatedly and emphatically stated that rebuttal testimony is not the place for the IOU applicant to present its evidence due to the basic principle of fairness, stating that "[p]roviding the basic justification in rebuttal is unfair, since parties are not generally given the opportunity to respond to rebuttal with testimony of their own."[432] Furthermore, SCE had five months between the time it submitted direct testimony and when intervenors submitted testimony, which provided plenty of time to submit update testimony. The Commission should reject SCE's request based on fairness alone.

Even if the Commission were to allow SCE's request to be considered, the proposed funding for this project should also be denied because SCE has failed to demonstrate that the benefits outweigh the costs. In fact, SCE readily admits that it "did not perform a cost benefit analysis for the IVR Refresh project."[433] Ratepayers should not fund a project that even SCE has not determined the benefits would outweigh the cost. Having ratepayers fund an unsupported project, especially in the midst of an economic crisis, would be unreasonable and unjust.

For the above reasons, TURN recommends a reduction of $5.193 million for this project.

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[431] *See, e.g.,* D.08-01-020, p. 2; D.15-11-021, p. 9.

[432] D.04-03-039, pp. 54, 84.

[433] Ex. TURN-47, DR TURN-SCE-082, Question 12.

17.6 Customer Care Services

Customer Care Services Summary (O&M Constant 2018 $000)

	Reduction
Customer Experience Improvement	($659)
Business Account Management Services (Hydraulic Services)	($1,151)
Customer Programs Management (NEM Interconnection Application Processing)	($458)
Transportation Electrification	($3,566)
Total Customer Care Services Reduction	**($5,834)**

17.6.1 Customer Experience Management

SCE requests an increase of $659,000 ($283,000 labor, $376,000 non-labor) of O&M expense for Customer Experience Improvement. SCE's request should be rejected because SCE is already conducting these activities currently, and it has not supported the need for an increase.

SCE states that two FTE resources are needed to manage a new program "that involves directly following up with customers who have expressed dissatisfaction or frustration with SCE's service."[434] When asked whether SCE currently follows up with customers who expressed dissatisfaction or frustration with SCE's service, SCE readily admits that it does, through resources in Customer Contact Center and Consumer Affairs, and it also conducts surveys via Medallia.[435] SCE claims that it is requesting two FTEs to manage a more comprehensive and structured program that will identify and follow up with customers.[436] While

[434] Ex. SCE-03 V05, p. 12.

[435] Ex. TURN-06, p. 17, citing DR TURN-SCE-068, Question 1.

[436] *Id.*

words such as "comprehensive" and "structured" sound nice, SCE has not established a need for two additional FTEs.

SCE states that the increase of $376,000 for non-labor expense is "driven by funding to support data analysis and research to improve core customer experiences."[437] SCE further explains that these activities include "improving and updating data quality," "market research for new rate structures," and "testing effectiveness of pilots based on customer experiences."[438] Again, SCE readily admits that it is already performing the above mentioned activities,[439] including one FTE to merge newly acquired data into SCE's existing database and two FTEs to perform market research activities.[440] Once again, now is not the time to engage in unnecessary spending that further burdens ratepayers, and SCE has not established why increased spending on these activities is necessary.

In its rebuttal, SCE claims that increased funding is necessary because "TURN fails to understand that SCE needs to refresh the data it purchases from external sources such as Acxiom periodically to ensure that SCE has accurate and updated customer data variables."[441] Yet, SCE later admitted that "SCE did [previously] refresh the data purchased from external sources at different time intervals,"[442] showing that it indeed has been able to refresh the data it purchases

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437 Ex. SCE-03 V05, p. 13.

438 Ex. SCE-03 V05 WP, p. 7.

439 Ex. SCE-03 V05 WP, p. 7.

440 Ex. TURN-06, p. 18, citing DR TURN-SCE-068, Question 2.

441 Ex. SCE-14, p. 62.

442 Ex. TURN-47, DR TURN-SCE-082, Question 13.

from external sources using existing funding. SCE's claim that it requires additional funding is unsupported and contradicted by its own spending history.

For the above reasons, TURN recommends a reduction of $659,000.

17.6.2 Business Account Management Services

SCE requests an increase of $1.151 million ($912,000 labor, $239,000 non-labor) for Hydraulic Services.

SCE states that these costs were previously funded through its EE program portfolio, but it wishes to move these costs into the GRC. SCE also claims that it expects that its 2021 energy efficiency portfolio funding will be reduced by $1.4 million, and it will seek that reduction as part of the EE Annual Budget Advice Letter process.[443] The Commission should reject this reasoning because GRC funding should not be increased because SCE plans to reduce spending in EE. Ratepayers also should not simply take SCE's word that it will seek the reduction later. SCE should continue to request this expense as part of the EE portfolio funding if necessary.

In its rebuttal, SCE states that Hydraulic Services have been funded by both EE programs and GRC O&M for over 20 years. However, SCE further reveals, for the first time, that these activities can no longer qualify for EE funding due to the lack of EE savings attributable to hydraulic services.[444] In other words, because these services no longer qualify for EE funding due to lack of EE benefits, SCE now seeks to include the costs of these services in the GRC instead. The Commission should find SCE's misleading statements and approach to be disingenuous. SCE first claims that it is moving these costs from EE to the GRC because the

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[443] Ex. SCE-03 V05, p. 28.

[444] Ex. SCE-14, p. 64.

activities are more suitable for GRC purposes, but it does not reveal that these activities no longer qualify for EE funding until its rebuttal testimony, after the intervenors opposed its proposal. Clearly, SCE is not *moving* costs from EE funding to the GRC because it is no longer able to receive EE funding for these activities. Instead, SCE is asking for an *increase* in authorized costs for these activities. Yet, an examination of historical pump test numbers reveals that activity levels have not increased and therefore increased funding would be unreasonable. In 2019, SCE conducted 4,244 pump tests, which is lower than the average of the preceding five years (4,301).[445] Thus, since the volume of pump tests has not increased, SCE's request for increased funding in the GRC should be rejected.

For the above reasons, TURN recommends a reduction of $1.151 million.

17.6.3 Customer Programs Management

SCE requests an increase of $458,000 in labor O&M to support the increased NEM application volume.

SCE's requested increase is driven by its forecast that the expected NEM interconnection volume is expected to grow by 100 percent between 2018 and 2021.[446] Given recent NEM application trends, this is an unrealistic forecast. In fact, NEM applications in 2019 were lower than NEM applications in 2015.[447] Furthermore, it should be noted that SCE made the same argument during the last GRC, projecting that NEM applications will increase to an average of

[445] Ex. SCE-14, p. 67.

[446] Ex. SCE-03 V05, p. 43.

[447] Ex. TURN-06, p. 19, citing DR TURN-SCE-068, Question 3.

112,247 in 2018-2020.[448] In reality, the average for 2018-2019 is 50,084, less than half of what SCE projected![449]

In its rebuttal, SCE claims that it expects the number of NEM applications to increase substantially over the next several years because of the new 2019 Building Energy Efficiency Standards.[450] However, SCE has made this argument before. As discussed above, SCE similarly argued for drastic NEM application increases in the previous GRC. Yet, in reality, the actual NEM applications were less than 50% of SCE's projections. SCE's unrealistic projections should be rejected once again.

Thus, the Commission should reject SCE's unrealistic growth projection and adopt a reduction of $458,000.

17.6.4 Transportation Electrification

SCE requests an increase of $3.566 million ($2.816 million labor, $0.750 million non-labor) for Transportation Electrification ("TE").

TURN supports the analysis of Public Advocates Office and agrees that SCE's request should be rejected in its entirety because SCE already receives funding in other TE proceedings, and the activities described in SCE's testimony are very similar to activities in other TE proceedings.[451] SCE has already received over $2.6 million in TE specific proceedings for TE-related labor costs, and it has a request for an additional $1.06 million pending before the

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[448] A.16-09-001, Ex. SCE-03, p. 83.

[449] Ex. TURN-06, p. 19, citing DR TURN-SCE-068, Question 3.

[450] Ex. SCE-14, p. 69.

[451] Ex. PAO-08P, pp. 33-38.

Commission.[452] SCE describes the non-labor portion of its request as funding "for the TE group to attend and participate in TE-related conferences and external engagements (e.g., TE Expos, Energy Policy and Sustainability Summits, Advanced Clean Transportation (ACT) expo)."[453] SCE goes on to explain that the non-labor forecast "also includes trade-related sponsorships, … and trade membership fees and dues."[454] TURN notes that conference sponsorships and trade group memberships generate good PR for SCE and should not be funded by ratepayers. Furthermore, "external engagement" sounds very similar to lobbying activities and should also be disallowed.

In its rebuttal, SCE argues that its requested increases are for the "general promotion of TE and assistance to customers, in partnership with Business Account Management," not for specific Commission-approved programs.[455] It further explains that "SCE is only seeking funding for non-program costs or program costs that precede the approval of a program."[456] However, SCE never supports its contention why an *increase* in funding is necessary for performing these activities since SCE already engages in these activities today. SCE has repeatedly touted the tremendous growth in TE that it expects to see during this GRC cycle. Hence, by all measures, SCE is already doing a great job with "general promotion" and advocacy for TE programs, as seen both by the TE growth it expects and the number of EV programs that the Commission has approved. Thus, an *increased* funding of $3.566 million is unreasonable

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[452] Ex. TURN-06, p. 20, citing DR TURN-SCE-068, Question 4a.

[453] Ex. SCE03 V05, p. 51.

[454] Ex. TURN-06, p. 20, citing DR TURN-SCE-068, Question 5.

[455] Ex. SCE-14, p. 71.

[456] Ex. SCE-14, p. 72.

and unjust when SCE already claims to have achieved extraordinary success with the promotion of TE. During this economic crisis, asking ratepayers to increase funding for a program that is meeting its purposes is unnecessary and unjustified.

For the above reasons, TURN recommends a reduction of $3.566 million.

17.7 OOR and Services and Fees

17.7.1 Service Guarantees: The Commission Has Denied Ratepayer Funding for This Program in Five Consecutive GRCs, Yet SCE Continues to Repeat the Same Arguments that Have Been Rejected

SCE requests an increase of $985,000 to fund the Service Guarantee Program.[457] The Commission has repeatedly rejected SCE's request for ratepayer funding of this program in 2006, 2009, 2012, 2015, and again in 2019.[458] Yet, SCE continues to make the same arguments again and again. As the Commission elegantly explained in the most recent GRC decision:

> Not only does the service guarantee provide some compensation to customers who are inconvenienced by SCE's failure to meet its service goals, the service guarantee creates an incentive for SCE to meet these goals. That incentive is most effective when it is paid by the shareholders, not ratepayers.[459]

Things have not changed, and having ratepayers fund this compensation to customers would diminish SCE's incentive to meet its service goals. Therefore, the Commission should once again reject ratepayer funding for this program. TURN recommends a reduction of $985,000.

17.8 Other Issues

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[457] Ex. SCE-03 V06, p. 68.

[458] D.06-05-016, p. 122; D.09-03-025, p. 108; D.12-11-051, p. 228; D.15-11-021, p. 194; D.19-05-020, p. 132.

[459] D.19-05-020, p. 133.

18. BUSINESS CONTINUATION

18.1 Seismic Assessment and Mitigation Program

For SCE's Business Continuation Business Planning Element (BPE), TURN only addressed SCE's forecast for its Seismic Assessment and Mitigation Program. TURN's analysis found SCE over-forecasted its costs for capital projects related to seismic mitigation projects in the transmission substation mitigation and at non-electric facilities categories. As will be addressed in greater detail below, SCE inappropriately applied a contingency factor to its forecasts and used a questionable methodology to further develop its non-electrical facilities forecast. The Commission should reduce SCE's forecast for Business Continuation capital expenditures for the Seismic Assessment and Mitigation Program by $26.511 million.[460]

18.1.1 Contingency Allowances are Unreasonable in the Context of Cost-of-Service-Ratemaking, and the Commission should Disallow SCE's Request for Contingency Costs in its Forecast for its Seismic Assessment and Mitigation Program.

For transmission substation mitigation projects, SCE applied a 35% contingency rate which represents $14.4 million in additional costs.[461] SCE also included $1,365,988 for contingencies in its forecast for non-electric facilities projects.[462] SCE argues that the inclusion of contingency amounts in project cost estimates is in line with industry practices and that the contingency is used to account for unforeseen conditions arising during the construction

[460] Ex. TURN-10 (Defever), p. 7: Summary of TURN Business Continuation Recommendations Table. TURN notes that TURN's recommended disallowance was presented as $26.803 million in the Joint Comparison Exhibit, see issue PAO-TURN-14 Business Continuation Capital.

[461] Ex. TURN-10 (Defever), p. 7: 13-16.

[462] *Id*. at p. 3: 12-13.

phase.[463] In the context of cost-of-service forecast ratemaking, however, these contingency allowances are not reasonable, and the Commission should disallow SCE's request for contingency allowances to be included in the forecasts for seismic assessment and mitigation projects at non-electrical facilities and transmission substations.

The Commission must view contingency costs through the lens of just and reasonable ratemaking. SCE's attempt to justify the inclusion of contingency allowances as "in line with industry practices,"[464] fails to recognize that the issue is not whether the construction industry routinely includes a measure of uncertainty in the cost estimates for individual projects. Nor is the crux of the issue is, how much contingency is appropriate for seismic assessment and mitigation projects, though TURN notes a 35% contingency factor is extremely high. SCE is not a private company estimating the costs of a construction project for the purposes of budgeting. The issue is how cost uncertainties should be addressed in the context of forecast-based, cost-of-service ratemaking. SCE is a regulated utility, and any cost requested in this GRC will ultimately be charged to ratepayers regardless of the amount actually spent on the project.

Under cost-of-service ratemaking, the utility is allowed to recover in rates those costs that are reasonably and prudently incurred to provide service and earn a return on its capital investments. Contingency allowances are unreasonable in this context because contingency costs are highly uncertain, they place the risk of cost overruns entirely on ratepayers, they reward shareholders for cost overruns, and they reduce incentives to minimize cost. For SCE's last GRC, the Commission declined SCE's request for contingency costs for software projects,

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[463] Ex. SCE-15, V1 (Daigler), p. 12: 10-11.

[464] *Id*. at p. 11: 18.

stating, "(W)e see no benefit to the ratepayers in this instance of carving exceptions and creating ratemaking policy which is only applicable to software projects."[465] The Commission should similarly decline to create an exception to ratemaking policy for SCE's seismic assessment and mitigation program and should deny the portion of SCE's request that accounts for contingency costs.[466]

18.1.1.1 SCE's Contingency Costs are Highly Speculative and are Unreasonable to Recover from Ratepayers.

SCE attempts to justify its contingency request by arguing it "accounts for unforeseen conditions arising during the construction phase"[467]. And, as SCE's witness testified, SCE's costs and corresponding contingency forecasts are speculative and subject to change.[468] In Decision 19-05-020, addressing SCE's 2018 GRC request, the Commission rejected SCE's contingency request, partially because the costs are too speculative, stating, "SCE's argument is that contingencies are necessary for the "uncertainties and variables that are unknown" demonstrates that the amounts are unpredictable and we therefore find SCE has not established these costs are reasonable."[469] The same rationale applies in the present GRC, allowing SCE to

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[465] D.19-05-020, p. 152.

[466] For transmission substation mitigation projects, SCE included $14.4 in additional costs for contingencies. SCE also included $1,365,988 for contingencies in its forecast for non-electric facilities projects.

[467] Ex. SCE-15, V1 (Daigler), p. 12.

[468] 5 RT 644: 14-22 (SCE/Daigler).

[469] D.19-05-020, p. 150.

include this additional costs that cannot be attributed to specific activities or items is counter to the requirement that all costs charged to ratepayers be found just and reasonable.[470]

18.1.1.2 For Transmission Substation Mitigation Projects, SCE Already Accounted for Cost Uncertainties by Significantly Increasing the Cost Estimates Provided by A Third Party Engineering Firm.

For Transmission Substation Mitigation Projects, SCE attempts to justify its staggering 35% contingency request by arguing "the higher level of contingency addresses the unique and complex scope of the projects that require the structural retrofitting of MEER buildings housing sensitive electrical relaying equipment."[471] While this may sound reasonable on the surface, the details of SCE's forecast highlight that the "unique and complex" scope of the projects has already been accounted for in SCE's forecasting methodology. When asked about the forecasting methodology used for these projects, SCE's response indicates SCE took cost estimates from a 3rd party engineering firm, and SCE cost estimators evaluated these cost estimates and then escalated the estimates to account for some missing cost components and some costs SCE thought the engineering firm had underestimated.[472] This process was done for 4 of 16 proposed projects.[473] For the remaining twelve projects, SCE increased the third party

[470] Pub. Util. Code §451.

[471] Ex. SCE-15, V1 (Daigler), p. 12.

[472] Ex. SCE-15, V1 (Daigler), Appendix, p. A-9, SCE Response to Public Advocates DR-1, Question 7; See also, 5 RT 635: 4-18 (SCE/Daigler).

[473] Ex. SCE-15, V1 (Daigler), Appendix, p. A-9, SCE Response to Public Advocates DR-1, Question 7.

engineering firms' estimates by 240%, which it claims is the average amount the third party engineering firm underestimated the project costs by, compared to SCE's estimators.[474]

The are multiple flaws in SCE's forecasting methodology that over-inflate the estimate which make SCE's request for an additional 35% contingency especially egregious. First, it is unclear why SCE felt the third party engineering firm's costs needed to be increased by 240% in the first place, given that SCE admits the firm has expertise in projects to address the structural integrity of buildings, a major component of the proposed projects.[475] Second, SCE calculated 240% as the average amount of underestimation by rounding up more than necessary, as the average amount of the underestimation shown in SCE's response is actually 234%, which would have been more closely rounded to 235%.[476] While TURN did not specifically take issue with this component of SCE's forecasting methodology, it serves to highlight the speculative nature of SCE's forecast and unreasonableness of SCE's request for an additional 35% contingency for this project which is inconsistent with forecast ratemaking. As noted by the Commission in Decision 19-05-020:

> "SCE is required to forecast what it projects to be a reasonable expense. To the extent the forecast is high, SCE can be confident it will recover on its capital expenditures and benefit its shareholders; to the extent the forecast is low, SCE's recovery may be deferred for review of the next test year."[477]

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[474] *Id.*

[475] 5 RT 6 37, 11-20 (SCE/Daigler).

[476] Ex. SCE-15, V1 (Daigler), Appendix, p. A-10, SCE Response to Public Advocates DR-1, Question 7, See Table: Transmission Substation Control/MEER Buildings Capital Forecast 2021-2023.

[477] D.19-05-020, p. 151.

18.1.2 SCE's Contingency Request Should be Rejected as it Would Charge Ratepayers for Unreasonable Costs.

For the reasons set forth above, the Commission should disallow SCE's request for contingency allowances to be included in the forecasts for its Seismic Assessment and Mitigation Program. Specifically, the Commission should remove $14.4 in continency costs for transmission substation mitigation projects and $1,365,988 for contingencies included in SCE forecast for non-electric facilities projects.

18.1.3 SCE's Non-Electric Facilities Forecast should be Further Reduced to Address an Additional Flaw in SCE's Forecasting Methodology.

TURN identified an additional issue with SCE's forecast for non-electrical facilities, SCE improperly included one outlier forecast cost with multiple recorded costs to calculate the average cost per square foot for all but one project in this category. The forecast cost that is included has a significantly higher cost per square foot than the remaining projects, and makes up over 60% of the total used to determine the average.[478] As shown in TURN witness Defever's testimony, the inclusion of this forecasted cost increased the average cost per square foot from $28.66 to $43.42, which SCE rounds up to $45 per square foot.[479] SCE has not sufficiently justified the inclusion of this outlier forecast cost.

SCE use of this forecasted amount in the average is inappropriate. The other costs included in the Company's calculation are known and measurable recorded costs whereas the $11,000,000 forecasted amount is only an estimate and it significantly skews the forecast. This coupled with the fact that as of March 2020, the actual cost of the forecasted project to date, was

[478] Ex. TURN-10 (Defever), p. 5: 6-11.

[479] *Id.*

only $332,542.[480] The Commission should reject SCE's forecast and should instead adopt TURN's proposal to recalculate the average cost without the forecasted project that is significantly higher than any of the historical costs.[481] This reduces the $45 cost per square foot to $28.66 per square foot and reduces SCE's forecast by $10,744,759.[482]

19. EMERGENCY MANAGEMENT

20. CYBERSECURITY

20.1 Overview

20.2 Cybersecurity Delivery and IT Compliance

20.3 Grid Mod Cybersecurity

20.4 Other Issues

21. PHYSICAL SECURITY

21.1 Overview

21.2 Work Force Protection/Insider Threat

21.3 Security Technology Operations and Maintenance

21.4 Protection of Grid Infrastructure Assets

21.5 Other Issues

22. GENERATION

22.1 Overview

22.2 Hydro

[480] Ex. TURN-10-Atch-1, p. 17, SCE Response to DR TURN-SCE-031, Q3b.

[481] Ex. TURN-10 (Defever), p. 6: 5-8.

[482] *Id.*

22.2.1 Borel O&M

TURN recommended a reduction to SCE's O&M forecast for the Borel hydroelectric plant to reflect the latest year of recorded cost data (2018) rather than using a five-year average that does not reasonably reflect expected future costs.[483] TURN's adjustment reduces non-labor O&M costs by $0.242 million.[484] In rebuttal testimony, SCE accepts TURN's proposed adjustment.[485] The Commission should therefore adopt TURN's recommendation.

22.2.2 San Gorgonio decommissioning costs

TURN recommends removing the 2.4 MW San Gorgonio decommissioning project from hydro capital and permanently disallowing the recovery of costs associated with this project. SCE forecasts $6.565 million in capital for decommissioning costs this project between 2019 and 2023.[486] Although these facilities are prime candidates for decommissioning, TURN opposes additional rate recovery because SCE previously requested, and received, funding for decommissioning this project in four prior GRCs starting with the 2009 case.[487] SCE now requests funding for the same project and scope of work in a fifth consecutive GRC. The Commission should decline to continue authorizing capital forecasts for the same scope of work. If the Commission does not adopt TURN's primary recommendation of a permanent disallowance, it should instead reject SCE's current forecast based on the low likelihood that the

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[483] Ex. TURN-09, pages 14-15.

[484] Ex. TURN-09, page15.

[485] Ex. SCE-16v1, page 9.

[486] Ex. SCE-5v1, page 113.

[487] Ex. TURN-09-Atch1, Attachment 5 (Excerpts from prior SCE GRCs relating to San Gorgonio).

specific scope of physical decommissioning work detailed in the application will occur during the current GRC cycle.

22.2.2.1 SCE's Repeated Request For The Same Scope Of Work Is Unreasonable

TURN's testimony includes excerpts from SCE's 2009, 2012, 2015 and 2018 GRC filings that describe the scope of proposed decommissioning work at San Gorgonio along with the associated costs.[488] In each of these showings, SCE described the exact same scope of work included in the current application.[489] The prior descriptions are identical, word for word, to the one provided in the current application.[490] While none of the work described and forecasted in these four prior GRCs has actually been performed, SCE ratepayers have been obligated to pay for a rate of return on the forecasted cost of removal since the 2009 GRC.[491]

The Commission previously expressed concern about efforts by IOUs to require ratepayers to repeatedly pay for work that is not performed. For example, in D.07-03-044 noted that "the Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past."[492] In the

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[488] Ex. TURN-09-Atch1, Attachment 5 (Excerpts from prior SCE GRCs relating to San Gorgonio).

[489] Ex. TURN-09-Atch1, Attachment 5, SCE 2009 GRC testimony, Volume 8, page 93 (The following work must be done prior to conveyance to satisfy them and the US Forest Service:
• Reline canal sections from the East and South Forks of the San Gorgonio to Raywood Flats
• Refurbish the flowline from Burnt Canyon to below SG1
• Remove flowline trestles in the area of Raywood Flats
• Remove all generation equipment, SG2 water tank, and some sections of flow line as directed by the US Forest Service)

[490] Ex. SCE-05v1, page 113.

[491] Ex. TURN-09, page 16.

[492] D.07-03-044, page 95

2011 PG&E GRC, the Commission stated that "cost disallowance of previously requested activities which were deferred and re-requested may be appropriate."[493] TURN is unaware of any previous example of an IOU being granted cost recovery five times for a scope of work that it failed to perform in five consecutive GRCs.

The Commission should recognize that continuing to approve the same forecast rewards SCE shareholders for bad forecasting and unrealistic projections. The repeated approval of identical forecasts enriches shareholders but does not promote accountability or ensure that rates are set only to recover costs reasonably likely to be incurred.

22.2.2.2 SCE Has Already Recovered More Than $4 Million For Inaccurate Forecasts

TURN's testimony provides a detailed history of SCE's forecasted costs for the same scope of work in the prior four GRCs and the general impact of those approved forecasts on revenue requirements. As explained by TURN witness Marcus, these approved capital forecasts were used to calculate a rate of return on the cost of removal which is added to accumulated depreciation. TURN calculates that these forecasts added approximately $4 million (nominal) to revenue requirements since the 2009 GRC, or $7.4 million in current (2021) dollars.[494] These calculations are simplified and should be taken as an approximation due to the complex factors that are incorporated into the Results of Operations model.[495] If the Commission approves SCE's current forecast, and the work is not completed in the current GRC cycle, then the cumulative costs to ratepayers of unperformed work will continue to increase.

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[493] D.11-05-018, page 28

[494] Ex. TURN-09, page 18, Table 18.

[495] 11 RT 1126 (TURN/Marcus). These factors could result in higher or lower outcomes.

22.2.2.3 The Identified Scope Of Work Is Highly Unlikely To Occur During The Current GRC Cycle

SCE's testimony forecasts $6.565 million in spending on San Gorgonio decommissioning between 2019-2023, with $5.15 million of physical decommissioning activities supposedly occurring between 2019 and 2021.[496] A review of recent developments demonstrates this forecast is unreasonable because there is a low probability that the specific scopes of work will be performed in the current GRC cycle. The Commission should therefore decline to approve SCE's forecast.

SCE's rebuttal testimony explains that decommissioning work will begin "once an agreement between the US Forest Service and participating entities is reached".[497] During hearings, SCE witness Buerkle stated that any such agreement would result in a supplemental use permit for the water conveyance systems and could involve a transfer agreement to move assets to the participating entities.[498] The defined project scope of work identified in the application, which covers physical decommissioning activities, can only commence <u>after</u> such an agreement has been reached with these stakeholders and a license surrender application has been <u>approved</u> by FERC.[499]

According to official correspondence from the Federal Energy Regulatory Commission (FERC), SCE initiated negotiations with various stakeholders over a license surrender

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[496] Ex. SCE-05v1, page 113; Ex. TURN-18 Workpapers to SCE-05, Vol. 1, BkA, page 111.

[497] Ex. SCE-16v1, pages 13-14. The "participating entities" include the City of Banning, Banning Heights Mutual Water Company, and the San Gorgonio Pass Water Agency.

[498] 4 RT 559: 21-28 (SCE/Buerkle)

[499] 4 RT 555: 15-26 (SCE/Buerkle); 4 RT 560: 1-13 (SCE/Buerkle); Ex. SCE-16v1, page 14:16-19.

application for San Gorgonio in 2014 and has been filing quarterly progress reports since December of 2017.[500] In the latest such report filed on February 25, 2020, SCE indicated that negotiations were continuing but could not offer any expected timeline for a resolution.[501] As of the date of evidentiary hearings, SCE had not reached an agreement or filed a license surrender application for San Gorgonio with the Federal Energy Regulatory Commission and could not offer any schedule for the date of a future filing or the timing of possible approval.[502]

Since none of these real-world constraints are considered in SCE's forecast, the Commission should recognize that there is no possibility of San Gorgonio decommissioning activities occurring on the timeline identified in SCE's application. In light of the extended duration of ongoing negotiations and the absence of any information to suggest a near-term resolution of outstanding disputes, the Commission should decline to find that the timing or amount of proposed decommissioning spending is reasonable or plausible. If the Commission declines to adopt TURN's primary recommendation (permanent disallowance), the current forecast should not be approved and SCE should instead be directed to provide a new estimate only after the negotiations are complete, a license surrender application has been filed with FERC, and there is a realistic timetable for physical decommissioning activities.

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[500] Ex. TURN-39, SCE letter to FERC (Update on Status of Dispute Resolution, February 25, 2020), footnote 1; FERC letter to SCE (Dispute Resolution at the San Gorgonio Project, March 9, 2020).

[501] Ex. TURN-39, SCE letter to FERC (Update on Status of Dispute Resolution, February 25, 2020). During evidentiary hearings, SCE witness Buerkle confirmed that this letter represents the most recent update provided to FERC (4 RT 556: 22-28)

[502] 4 RT 556-557 (SCE/Buerkle)

22.2.2.4 There Is No Basis For SCE's Claim That Total Decommissioning Costs Could Amount To $48 Million

SCE's direct testimony describes a complete scope of work for decommissioning the San Gorgonio facility forecasted to cost $6.565 million.[503] In rebuttal testimony, SCE asserts the existence of internal estimates suggesting total decommissioning costs of $48 million and claims that amounts requested in both the current and prior GRCs were never meant to cover the entire scope of work.[504] These "internal estimates" have never been provided and SCE offered no details to support this much larger figure. During hearings, SCE witness Buerkle admitted that these costs have never been identified in any prior GRC application.[505] Mr. Buerkle agreed that these additional costs would have been shown in prior GRCs had the forecast horizon extended beyond the five years associated with the initially identified scope of work.[506]

A review of prior GRC forecasts does not support SCE's claims. None of SCE's previous GRC filings even hint at the existence of additional costs beyond the described scope of work. In the 2009 GRC, SCE forecasted the entire cost of decommissioning ($7 million) would be incurred in 2009 with no additional expenditures in 2010 or 2011.[507] In the 2012 GRC, SCE forecast the entire cost of decommissioning ($6.5 million) would be incurred in 2011 and 2012 with no additional expenditures in 2013, 2014 or 2015.[508] In the 2018 GRC, SCE forecast a total

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503 Ex. SCE-05v1, page 113.

504 Ex. SCE-16, pages 11, 16.

505 4 RT 557-558 (SCE/Buerkle)

506 4 RT 558-559 (SCE/Buerkle)

507 Ex. TURN-09, page 17, Table 17; Ex. TURN-09-Atch1, Attachment 5, page 104 (SCE 2009 GRC testimony, Volume 8 workpapers, page B-10)

508 Ex. TURN-09, page 17, Table 17; Ex. TURN-09-Atch1, Attachment 5, page 108 (SCE 2012 GRC testimony, Volume 7 Part 2 workpapers, page B-8)

of $6.4 million in spending through 2019 with no additional expenditures in 2020.[509] Had there been a reasonable expectation of additional costs, these costs would have been shown in one or more years following the completion of the initial scope of work. The fact that prior SCE forecasts assumed zero additional spending in the following years contradicts the argument that additional costs were not disclosed because the initial scope of work continued for the entire five year forecast horizon. The Commission should therefore reject SCE's unsupported claims regarding the potential for additional decommissioning costs not shown in the current (or any prior) application.

22.3 Mountainview

22.3.1 Capital Adjustment To Remove Turbine Rotor Purchase

TURN recommended a $54 million reduction to SCE's capital forecast to reflect the fact that new turbine rotors will not be needed.[510] Specifically, TURN proposed removing $18 million in 2020 and $36 million 2021 to implement this adjustment. In rebuttal testimony, SCE agreed that the rotor replacements are "highly unlikely" in the current GRC cycle and did not oppose TURN's recommended adjustments.[511] The Commission should therefore adopt TURN's recommendation.

22.3.2 O&M Expense Adjustments

TURN recommended two adjustments to SCE's O&M forecast for Mountainview. First, TURN recommended a reduction of $0.822 million to account for lower expected payments

[509] Ex. TURN-09-Atch1, Attachment 5, pages 118-119 (SCE 2018 GRC testimony, Ex. SCE-05 Volume 3 Book A workpapers, pages 88, 320)

[510] Ex. TURN-09, page 19.

[511] Ex. SCE-16v1, pages 20-21.

under the Contract Service Agreement (CSA) with General Electric due to changing operations at the facility attributable to greater renewable resource production.[512] Second, TURN proposed applying a lower and more appropriate non-labor escalation rate to costs under the CSA. This change results in a reduction of $0.158 million.[513] In rebuttal testimony, SCE agreed to both of TURN's adjustments and modified the escalation rate through an errata to direct testimony.[514] The Commission should therefore adopt both of TURN's O&M recommendations.

22.4 Solar

22.5 Fuel Cell

22.5.1 O&M Adjustment

TURN recommended a reduction of $0.018 million to prevent the double counting of 2014-2017 facilities charges for interconnection that were averaged and included in non-labor expenses.[515] In rebuttal testimony, SCE does not oppose TURN's recommendation to correct for the double counting.[516] The Commission should therefore adopt TURN's recommendation.

22.6 Catalina

22.6.1 TURN O&M Cost Recommendation Accepted by SCE

TURN's prepared testimony recommended a $103,000 reduction to SCE's non-labor O&M forecast to remove an atypical outage that occurred in 2016 and is unlikely to recur in the

[512] Ex. TURN-09, pages 21-22.

[513] Ex. TURN-09, pages 20.

[514] Ex. SCE-16v1, page 20.

[515] Ex. TURN-09, pages 26-27.

[516] Ex. SCE-16v1, page 36.

current GRC cycle.[517] This outage cost was included in the forecast because SCE relied upon a five-year historic average for non-labor costs. In rebuttal testimony, SCE did not oppose this recommendation.[518] The Commission should therefore adopt TURN's recommended adjustment.

22.6.2 SCE Has Not Demonstrated The Reasonableness Of Its Capital Forecast For Repowering

SCE seeks approval for a forecast of $40.16 million in capital expenditures for the Catalina Pebbly Beach Generating Station, of which $25.486 is forecasted occur between 2019-2021.[519] Most of this request ($34.3 million) involves the Catalina repower project and is assumed to result in $23.16 million between 2019 and 2021.[520] The first two phases of the project, involving four new diesel engines, are assumed to be completed by the end of 2022 in order to meet a January 1, 2023 compliance requirement established by the South Coast Air Quality Management District (SCAQMD).[521] A third phase involving an additional two diesel units is assumed to be complete by April of 2023.[522] Due to new information provided during and after evidentiary hearings, TURN recommends that no capital spending for this project be approved in the current GRC.

In rebuttal testimony, SCE urges the Commission to adopt its original forecast and claims that it has "met its burden to demonstrate the reasonableness of the technology chosen (diesel

[517] Ex. TURN-09, pages 25-26.

[518] Ex. SCE-16v1, page 25.

[519] Ex. SCE-16v1, page 25.

[520] Ex. SCE-16v1, page 25.

[521] Ex. SCE-16v1, page 29.

[522] Ex. SCE-16v1, page 29.

generators), project plans and schedule and costs."[523] During and after evidentiary hearings, additional information emerged that raises significant doubts about these claims. In response to cross-examination, SCE witness Buerkle admitted that the proposed capital forecast was developed prior to the results of an ongoing feasibility study into alternatives.[524] The final feasibility study was submitted into the record more than one month after SCE's witness appeared on the stand during evidentiary hearings.[525] Because of the late submission of the final study, TURN was not able to cross-examine any SCE witness about its contents.[526]

The feasibility study identifies a variety of options that could be pursued as an alternative to a significant amount of the diesel generation included in SCE's forecast. For example, the study identifies the potential for cost-effective energy efficiency with a 6-year payback to lower total consumption by 21% and reduce the need for new generation.[527] The study also considered options for replacing two existing generators with new diesel units by January 1, 2023 and deferring other capacity additions until 2027.[528] Further, the study considered 5%, 60% and 100% renewable energy options and identified a number of areas for future study.

Despite SCE's forecast assumption that four new diesel units would be installed by the end of 2022, Mr. Buerkle conceded that no final decision has been made to proceed with the

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[523] Ex. SCE-16v1, page 29.

[524] 4 RT 539: 6-11 (SCE/Buerkle)

[525] Ex. SCE-44, submitted August 21, 2020.

[526] A draft version of the study was completed three days before Mr. Buerkle appeared at evidentiary hearings. SCE included a cryptic reference (citing only a DR by PAO) to the document in an updated exhibit list circulated the night before Mr. Buerkle took the stand but did not provide a copy of the study to TURN prior to hearings.

[527] Ex. SCE-44, Catalina Repower Feasibility Study, pages 11, J23.

[528] Ex. SCE-44, Catalina Repower Feasibility Study, page 10.

installation of new diesel generation at Catalina, that no equipment has been ordered, and that management had not approved the expenditure of any funds for the project.[529] In response to additional questions, SCE further admitted that the forecasted in-service dates for any new diesel generation were illustrative, that no binding commitments had been made to suppliers or vendors, and that SCE may only pursue Phase 1 of the project identified in its application.[530] These facts undermine the reasonableness of the assumption that any new projects will be operational in 2021. As a result, the Commission should recognize that the forecasted capital spending provided by SCE is presumptively inaccurate and unreasonable.

Mr. Buerkle agreed that SCE is continuing to explore alternatives to diesel generation and is actively engaged "in discussions with landholders on obtaining land to build renewable projects and potentially storage".[531] These efforts include consideration of power purchase agreements with third-party developers that would not involve ratebased capital investment.[532] In the event that ongoing efforts to build renewable energy and storage projects are successful, Mr. Buerkle agreed that some of the proposed diesel generating units may not be needed.[533]

Although SCE's rebuttal testimony identifies an intent to hold an all-source procurement solicitation for the purpose of considering replacement options, Mr. Buerkle noted that none of the details or timing of the solicitation have yet been determined.[534] The final feasibility study

[529] 4 RT 539-540 (SCE/Buerkle)

[530] 4 RT 541-542 (SCE/Buerkle)

[531] 4 RT 542-543 (SCE/Buerkle)

[532] 4 RT 544: 12-17 (SCE/Buerkle)

[533] 4 RT 544: 2-6 (SCE/Buerkle)

[534] Ex. SCE-16v1, page 28; 4 RT 552: 2-22 (SCE/Buerkle)

indicates the SCE will launch a Request For Offers (RFO) in 2021 or 2022 and that SCE's actions will be reviewed "as part of SCE's General Rate Case."[535] In a response to a TURN data request, SCE indicated that an all source RFO may be launched in 2021.[536] To the extent that SCE assumes that this review is occurring in the current GRC, the Commission should clarify that the lack of timely information and the absence of a clear plan prevents review until the next GRC cycle.

SCE's desire to consider non-diesel alternatives was previously communicated to the South Coast Air Quality Management District (SCAQMD) in the course of its process considering amendments to Rule 1135. In an August 16, 2018 letter to the SCAQMD, SCE requested additional time to comply with the Rule because, "rather than replacing the engines with Tier 4 diesel engines, SCE is exploring cleaner options as part of our integrated resource planning effort for PBGS."[537] The letter states that the additional time would allow SCE, as part of its "resource planning process", to "seek input from various stakeholders including the CPUC" regarding the potential for alternative options.[538] Despite this pledge to SCAQMD, SCE's capital forecast assumes that no alternative options will be deployed.

The final Rule adopted by SCAQMD permits SCE to seek a three-year extension of the compliance deadline for Catalina Island to allow for consideration of alternatives to diesel

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[535] Ex. SCE-44, "Repowering Catalina Island", SCE summary, page 1.

[536] Ex. TURN-077, SCE response to TURN Data Request 109, Q1b.

[537] Ex. TURN-40, SCE response to TURN Data Request 91, Q2b, SCE letter to SCAQMD, August 16, 2018, page 2.

[538] Ex. TURN-40, SCE response to TURN Data Request 91, Q2b, SCE letter to SCAQMD, August 16, 2018, page 2.

generation.[539] The extension option was adopted by SCAQMD as a direct result of SCE's engagement in the rulemaking process.[540] Under an extension scenario, SCE would only be required to install two new cleaner diesel engines by January 1, 2023.[541] Mr. Buerkle noted that SCE is actively considering seeking an extension and that "one potential outcome is only installing two of the new cleaner diesel engines by 2023 and then availing ourselves of this extension, which would allow us more time to work through potential renewables projects, energy efficiency, demand response, storage."[542] In this case, the alternatives could substitute for some of the diesel units included in SCE's capital forecast.[543] If SCE executes power purchase agreements with third parties for the development of new resources, these costs would be recovered as purchased power costs outside the GRC and not as capital spending. This likely outcome raises additional doubts about the legitimacy of SCE's capital forecast.

TURN's prepared testimony expressed concerns about the need for the entire project scope identified in SCE's testimony. Specifically, TURN opposed any approval of spending on facilities coming into service post-2021 and raised concerns about the need for the three phases involving six diesel units.[544] TURN agreed that costs for Phase 1 units reaching commercial operations in 2021 and needed to meet the SCAQMD requirement should be approved.[545]

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[539] Ex. TURN-41, South Coast Air Quality Management District Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135, October 2018, page 1-10.

[540] 4 RT 551 (SCE/Buerkle).

[541] Ex. TURN-41, South Coast Air Quality Management District Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135, October 2018, page 1-10.

[542] 4 RT 549-550 (SCE/Buerkle).

[543] 4 RT 550: 19-24 (SCE/Buerkle).

[544] Ex. TURN-09, pages 23-25.

[545] Ex. TURN-09, page 25.

Further, TURN witness Marcus recommended that SCE be required to affirmatively demonstrate, in its next GRC, that it fully considered alternatives to diesel and pursued options that minimize both cost and environmental impacts.[546] These recommendations assumed that SCE was planning to install new diesel generation in 2021 to meet SCAQMD requirements.

During evidentiary hearings, TURN witness Marcus responded to questions from the ALJ regarding his recommendations for the Catalina Island repower. Mr. Marcus indicated that the Commission should decline to authorize capital spending on the Catalina repower project beyond the "first project" needed to meet regulatory requirements. To the extent that SCE engages in spending in 2019, 2020 and 2021 on the first set of replacement project that "comes into service in 2021", Mr. Marcus agreed that the spending should be deemed reasonable.[547] When asked how the Commission should address this proposal in light of alternatives under consideration, Mr. Marcus explained that "from our perspective what is acceptable is putting that first plant in service."[548]

TURN's original recommendation should therefore be understood to support the need for the first set of diesel generation units to be installed. However, Mr. Marcus assumed that SCE would be engaging in capital spending starting in 2019 in order to successfully install the first set of replacement units in 2021. Based on the updated information provided during hearings and in the feasibility study submitted on August 20, it is no longer reasonable to assume that any new diesel generation will be operational in 2021. To the extent that SCE plans to bring new units

[546] Ex. TURN-09, page 25.

[547] 11 RT 1145: 1-6 (TURN/Marcus)

[548] 11 RT 1145: 23-24 (TURN/Marcus)

online post-2021, there is no basis for approving the proposed capital spending forecast covering 2019-2021 since project spending will not result in any plant placed into service in the test year.

With the benefit of this updated information, TURN now recommends that no capital spending for this project be approved in the current GRC and that no new generation should be assumed to achieve commercial operations and become plant in-service. Further, SCE should be required to submit its proposals in the Integrated Resources Planning docket and demonstrate the reasonableness of their choices in the next GRC. This approach will ensure that the Commission is able to fully review the reasonableness of actions that cannot be assessed at this juncture given the uncertainty surrounding the timing and scope of the overall project.

22.7 Palo Verde

22.7.1 O&M Costs Should Be Updated To Reflect The Most Recent Budget

SCE owns a 15.8% share of the Palo Verde nuclear plant which is operated by majority owner Arizona Public Service (APS) company. SCE's O&M forecast is based on budget information provided by APS to the Palo Verde co-owners. Relying on a budget prepared by APS in 2018, SCE requests $73.105 million ($2018) for non-labor expenses in 2021.[549] This figure incorporates a correction of more than $5 million from SCE's original testimony to reflect an erroneous reliance on nominal (rather than real) dollars in response to TURN's concern over the lack of support for rising budgets given APS budget forecasts.[550] Based on updated budget forecasts provided by APS to SCE in August of 2019, TURN recommends a reduction of $1.516

[549] Ex. SCE-05e1, page 179, Figure V-15.

[550] Ex. SCE-16v1, page 44; Ex. TURN-09, page 5.

million ($2018) to ensure consistency with the most recent and accurate budget developed for the Palo Verde co-owners.[551]

SCE opposes TURN's recommendation on the basis that the updated APS budget "was not available to SCE at the time it developed its 2021 Palo Verde O&M non-labor forecast."[552] In fact, the updated budget was provided to SCE one month before the GRC application was filed.[553] During hearings, SCE witness Champ stated that although he received the updated budget from APS one month before testimony was due, SCE should not be required to incorporate this information into the O&M forecast because the budget was not "approved" by the Palo Verde co-owners until November 20, 2019.[554] However, Mr. Champ agreed that TURN's recommended forecast, which is based on the budget provided to SCE on July 31, 2019, is consistent with the final budget "approved" on November 20.[555]

The only contested issue is whether the updated APS budget should be relied upon as the basis for SCE's O&M forecast. SCE does not dispute the accuracy of the final APS budget or the fact that SCE expects to be charged their share of the lower amount of O&M costs included in the updated budget document. Since the adoption of TURN's request would align expected costs with authorized revenues, the Commission should find it to be reasonable. By contrast, SCE's

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[551] In section 22.7.2, TURN recommends an additional $0.139 million reduction related to Nuclear Energy Institute dues.

[552] Ex. SCE-16v1, page 44.

[553] Ex. TURN-09-Atch1, Attachment 4, 2020 Palo Verde Generating Station Budget (July 31, 2019).

[554] 4 RT 582 (SCE/Champ)

[555] 4 RT 584: 6-9 (SCE/Champ)

request would result in an additional $1.516 million/year of ratepayer revenues that it does not expect to spend on Palo Verde O&M (and would instead be retained by shareholders).

The Commission should require SCE to rely upon the updated APS budget because it represents the most accurate information available to SCE at the time testimony was submitted. The final "approved" budget was available to SCE in late 2019 and could have been incorporated into errata or rebuttal testimony. There is no evidence that the final "approved" budget differs from the original version provided to SCE.

SCE's witness could not cite any policy preventing the use of this updated information but instead argued that he could only rely on the most recently approved budget available prior to the GRC filing date.[556] This argument is not persuasive. SCE has already asked the Commission to consider updated information and new recommendations relating to generation based on materials first introduced in both rebuttal testimony and after the conclusion of evidentiary hearings. For example, SCE asks the Commission to consider the results of a feasibility study relating to Catalina island that was available in draft form only a few days before the start of evidentiary hearings and was finalized after hearings had concluded.[557] SCE also updated its Catalina capital forecast in rebuttal testimony based on updated information on recorded capital spending in 2019.[558] Additionally, SCE indicated its intention to modify its treatment of Palo

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[556] 4 RT 584: 1-5 (SCE/Champ).

[557] Ex. SCE-44.

[558] Ex. SCE-16v1, page 27.

Verde water sales revenues in June of 2020 after receiving a TURN data request and made this change in rebuttal.[559]

The Commission has offered guidance on this issue in other proceedings that relate to nuclear power plants. In A.16-03-004, SCE opposed TURN's efforts to update the Decommissioning Cost Estimate (DCE) for the San Onofre Nuclear Generating Station Unit 1 based on actual contract cost information that became available after the DCE was originally prepared and testimony had been submitted. In D.18-11-034, the Commission rejected SCE's position and instead found that new information which became available during the course of the proceeding should be considered.[560]

To prevent unjust enrichment by SCE, and ensure that the final decision authorizes only amounts that are deemed reasonable to perform the anticipated scope of work, the Commission should adopt TURN's recommendation and make a $1.516 million downward adjustment to the test year forecast.

22.7.2 Nuclear Energy Institute Dues

TURN's direct testimony recommended that the half the costs of SCE's Nuclear Energy Institute (NEI) membership be removed from rates, consistent with prior Commission Decisions, to recognize that the organization has a dual role of promoting nuclear power and working to cut industry costs.[561] This recommendation would reduce SCE's request by $139,000.

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[559] Ex. TURN-042, SCE response to TURN Data Request 62, Q28 revised; Ex. SCE-16v1, page 47.

[560] D.18-11-034, pages 34-35 ("We disagree with SCE in that information known prior to approval of the DCE should be considered when approving the proposal.")

[561] Ex. TURN-9, page 9.

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."[562] 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."[563] Despite SCE's claims that all advocacy costs are included in 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."[564] 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."[565] Absent such details, the Commission determined that a 50/50 split of NEI dues between shareholders and ratepayers was reasonable.[566]

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.[567] In the intervening years since these two Decisions, no utility has come forward with a "detailed description" of NEI activities,

[562] D.06-05-016, page 35.

[563] D.06-05-016, page 35.

[564] D.06-05-016, page 35.

[565] D.06-05-016, page 35.

[566] D.06-05-016, Finding of Fact 10.

[567] D.07-03-044, page 106.

costs and benefits to ratepayers that has resulted in a change to the 50/50 assignment of NEI dues.

SCE's direct testimony did not clearly explain its intention to seek rate recovery for 100% of NEI dues. However, the original direct testimony stated that it was providing a showing of "activities and ratepayer benefits related to SCE's participation with the Nuclear Energy Institute, consistent with D.06-05-016."[568] Despite this statement, there was no such showing provided in the referenced sections of SCE's direct testimony.[569] SCE modified its direct testimony five days before its witness appeared on the stand to eliminate the statement that a showing of "activities and ratepayer benefits" had been included in its testimony.[570] Even after this modification, SCE's prepared testimony failed to provide any of the additional information required by D.06-05-016.[571] The only reference to the ratepayer benefits of NEI's programs can be found in a single narrative paragraph of SCE's rebuttal testimony mentioning several specific activities that benefit nuclear plant owners and claiming that "Palo Verde would likely have incurred much higher costs than its NEI dues to achieve the same benefits but for its participation in NEI."[572] However, SCE failed to provide a breakdown of the specific costs and benefits associated with any particular NEI activities or any quantification of the portion of NEI's overall budget that supports cost-saving activities (while excluding funds spent on nuclear power

[568] Ex. SCE-5, page 172
[569] 4 RT 589: 1-7 (SCE/Champ)
[570] Ex. SCE-5v1e2, page 172
[571] 4 RT 589: 8-14 (SCE/Champ)
[572] Ex. SCE-16, page 46.

advocacy). The generic statements in SCE's rebuttal testimony do not come close to satisfying the Commission's articulated standard for altering the 50/50 split of dues.

In rebuttal testimony, SCE argues that the Commission should rely upon the percentage of NEI membership dues attributable to "lobbying expenses" as the basis for determining the portion of costs to be covered by shareholders.[573] This portion is determined by NEI and provided as an itemized amount on the bills sent to members. Although SCE's testimony states that the portion of dues attributable to lobbying has only been specified by NEI "more recently", SCE subsequently conceded that NEI has disclosed this information "continually" since 1994 as required under federal law.[574] Under cross-examination, SCE witness Champ could not identify what new information NEI began providing "more recently" that SCE relies upon to make its showing.[575]

As explained in a data response provided by SCE, the amount of funds a non-profit organization like NEI devotes to "lobbying expenses" are disclosed to the Internal Revenue Service annually pursuant to Internal Revenue Code (IRC) §6033(e) and are based on the definition of "lobbying" included in IRC §162(e)(1).[576] The 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

[573] Ex. SCE-16, page 46.

[574] Ex. TURN-44, SCE response to TURN Data Request 91, Q3(b).

[575] 4 RT 596: 9-18 (SCE/Champ)

[576] Ex. TURN-44, SCE response to TURN Data Request 91, Q3(a).

officials regarding agency actions.[577] The limited scope of activities classified as "lobbying" does not include any general advocacy outside of the activities referenced in §162(e)(1).

The provision of the NEI membership invoice, which includes a single line-item showing dues attributable to "lobbying", does not satisfy the prior direction provided by the Commission. As a threshold matter, the Commission previously rejected a similar showing with respect to dues paid to the Edison Electric Institute (EEI). In SCE's 2018 GRC, the Commission found that SCE's submission of an EEI invoice providing guidance for allocating costs between shareholders and ratepayers was "insufficient evidence to establish the portion of the invoice which should be recovered from ratepayers."[578] 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.[579]

Although the Commission previously held that the portion of costs relating to "advocacy" for nuclear power should be assigned to ratepayers, SCE uses "lobbying" expenditures as a complete proxy for "advocacy." SCE was not able to provide any information about the extent to which NEI assigns costs related to various forms of advocacy to "lobbying" expenditures. In response to a data request from TURN that sought information on "the extent to which" costs for 14 categories of advocacy performed by NEI were considered lobbying expenditures, SCE provided generic responses that declined to identify the portion of costs for each identified

[577] 26 USC §162(e)(1).

[578] D.19-05-020, page 250.

[579] D.19-05-020, page 250.

activity that had been assigned to "lobbying".[580] Moreover, SCE did not attempt to demonstrate the extent to which each of the 14 categories of advocacy provided direct benefits to ratepayers.

TURN's attempt to inquire into the costs and benefits of NEI spending on the 14 categories of advocacy did not yield any substantive results. During cross-examination, SCE witness Champ agreed that he was unfamiliar with the entire portfolio of advocacy activities conducted by NEI.[581] Moreover, Mr. Champ agreed that he could not state whether a wide array of NEI's advocacy expenditures are included in the calculation of lobbying costs.[582]

When asked whether all of NEI's public policy advocacy activities are covered by the specific definition of "lobbying" in §162(e)(1), SCE witness Champ agreed that "there may be a difference between lobbying and advocacy."[583] One example of NEI advocacy involves support for another organization named "Nuclear Matters" which is described as a "national coalition that works to inform the public and policymakers about the clear benefits of nuclear energy."[584] According to NEI's 2018 tax disclosures, NEI provided $3.576 million to support Nuclear Matters.[585] By comparison, NEI reported only $1.329 million in "lobbying" expenditures during the same year, an amount that does not appear to include any costs attributable to Nuclear Matters.[586] SCE witness Champ agreed that the portions of NEI's "Nuclear Matters" website explaining efforts to "educate and activate" stakeholders "in support of nuclear energy" describe

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[580] Ex. TURN-44, SCE response to TURN Data Request 91, Q3(c); 4 RT 606: 1-2 (SCE/Champ)
[581] 4 RT 607: 3-7 (SCE/Champ)
[582] 4 RT 607: 13-17 (SCE/Champ)
[583] 4 RT 593: 12-13 (SCE/Champ)
[584] Ex. TURN-44, Nuclear Matters website "About" page 1.
[585] Ex. TURN-76, NEI 2018 Form 990, Schedule I, Part II.
[586] Ex. TURN-76, NEI 2018 Form 990, Schedule C, Part III-B.

a form of advocacy.[587] Since these activities do not clearly fall within the scope of "lobbying" as defined in §162(e)(1), there is no basis for SCE to assert that NEI's calculation of lobbying costs include all programs relating to nuclear power advocacy.

Other documents introduced during evidentiary hearings show many different types of advocacy described on NEI's website and in their 2019 Annual Plan.[588] SCE fails to make any showing with respect to the costs of these activities, their benefits to ratepayers and the portion of related costs that are assigned by NEI to "lobbying" expenditures. Moreover, NEI's Form 990 itemizes over $500,000 in grants to 31 other non-profit organizations that are funded by NEI's general revenues.[589]

When asked to respond to claims that NEI membership may have resulted in cost savings for Palo Verde, Mr. Marcus noted that these potential savings justify the recovery of 50 percent of membership costs in rates.[590] But Mr. Marcus explained that the remaining 50 percent should be allocated to shareholders because

> NEI does things with its money that if Edison did the same things with its money it would have been disallowed, based on Commission precedent going back to the 1970s, such as advertising, making grants to other organizations, setting up grassroots organizations, such as Nuclear Matters. These are things that Edison would not be allowed to do as a regulated utility, whether they benefit shareholders or not.[591]

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[587] 4 RT 606: 3-15 (SCE/Champ)

[588] Ex. TURN-44, NEI website section "Take Action", "The Advantages of Nuclear Energy", "Advocacy"; Ex. TURN-45-C (Nuclear Energy Institute 2019 Annual Plan).

[589] Ex. TURN-76, NEI 2018 Form 990, Schedule I, Part II.

[590] 11 RT 1120 (TURN/Marcus)

[591] 11 RT 1119: 7-16 (TURN/Marcus)

Given the consistent treatment of NEI dues by the Commission since the issuance of D.06-05-016, the absence of any new evidence provided by SCE to support a change in the policy, and SCE's failure to demonstrate that the portion of NEI dues attributable to lobbying expenditures is a reasonable proxy for the amount spent on advocacy efforts, TURN submits that SCE has failed to satisfy its burden of proof. The Commission should therefore decline to alter the 50/50 sharing of NEI dues that has been applied to IOUs since the issuance of that Decision.

22.7.3 SCE's Proposal To Reverse The Longstanding Practice Of Crediting Customers With All Water Sales Revenues Is Unreasonable

In rebuttal testimony, SCE announced its intention to treat Palo Verde water sales revenues as Non-Tariffed Products and Services (NTP&S). These revenues involve a reclamation plant located at Palo Verde with surplus treatment capacity and excess water available for resale to the nearby Redhawk combined cycle gas-fired power plant owned by an affiliate of APS.[592] Since 2018 these water sales revenues, which have occurred for almost 20 years, were directly credited by SCE against Palo Verde O&M costs charged to its customers.[593]

TURN recommends treating water sales revenues as Other Operating Revenues (OOR) according to Generally Accepted Accounting Principles.[594] This treatment results in a $0.474 million credit against rates in the test year.[595] TURN opposes SCE's effort to reclassify these revenues as NTP&S and deprive ratepayers of the full value of their ongoing expenditures at

[592] Ex. TURN-09, page 12.

[593] 4 RT 572: 3-18 (SCE/Champ)

[594] Ex. TURN-09, page 12.

[595] Ex. TURN-09, page 12, *citing* SCE response to TURN Data Request 62, Q28. This data response was originally received on April 22. SCE offered a revised version on June 2nd that explains that the revenues are being treated as NTP&S.

Palo Verde. If classified as NTP&S, ratepayers would only receive 30% of the gross revenues with the remaining 70% credited to shareholders.[596]

SCE's proposal to reclassify these revenues is troubling and should be understood as a brazen and inappropriate attempt to benefit shareholders at the expense of its own customers. SCE has extensive institutional experience with OOR treatment, NTP&S policy and the calculation of Palo Verde O&M costs. Despite this longstanding knowledge, SCE's primary witness justifies the change because he was personally not "aware of nontariff products and services" prior to the current proceeding.[597] Only after Mr. Champ become personally "aware" of the option to reclassify revenues as NTP&S during the course of this proceeding did SCE propose this new treatment.[598] According to SCE witness Champ, the proposal is intended to "comply" with the NTP&S revenue sharing mechanism adopted over 20 years ago in D.99-09-070.[599]

The Commission should reject SCE's characterization that the proposal constitutes deferred compliance with existing rules governing NTP&S. SCE has not satisfied the requirements laid out in Affiliate Transaction Rule VII originally adopted in D.97-12-088 and modified in D.98-08-035. This Rule outlines a series of conditions precedent to the offering new non-tariffed products and services. Since SCE has not previously sought to classify Palo Verde

[596] Ex. SCE-16v1, page 47.

[597] 4 RT 578: 8-12 (SCE/Champ)

[598] 4 RT 578-579 (SCE/Champ)

[599] 4 RT 578-579 (SCE/Champ)

water sales as NTP&S, this product offering would be considered "new"[600] and therefore must satisfy the following requirements:[601]

> **VII(D). Conditions Precedent to Offering New Products and Services**
> This Rule does not represent an endorsement by the Commission of any particular non-tariffed utility product or service. A utility may offer new non-tariffed products and services only if the Commission has adopted and the utility has established:
>
> 1. A mechanism or accounting standard for allocating costs to each new product or service to prevent cross-subsidization between services a utility would continue to provide on a tariffed basis and those it would provide on a non-tariffed basis;
> 2. A reasonable mechanism for treatment of benefits and revenues derived from offering such products and services, except that in the event the Commission has already approved a performance-based ratemaking mechanism for the utility and the utility seeks a different sharing mechanism, the utility should petition to modify the performance based ratemaking decision if it wishes to alter the sharing mechanism, or clearly justify why this procedure is inappropriate, rather than doing so by application or other vehicle.
> 3. Periodic reporting requirements regarding pertinent information related to non-tariffed products and services; and
> 4. Periodic auditing of the costs allocated to and the revenues derived from non-tariffed products and services.

Since the Commission has not yet "adopted" any of the findings required under the Rules, and SCE has not either established the mechanisms required by (D)(1) and (D)(2) or demonstrated how such costs will be reported and audited (pursuant to (D)(3) and (D)(4)), it is premature for water sales revenues to be treated as NTP&S. SCE has not presented evidence on cross-subsidization or provided details relating to a mechanism for the treatment of benefits and revenues. The rules do not permit SCE to unilaterally determine that NTP&S treatment applies to a particular product and automatically incorporate this information into its annual NTP&S report,

[600] D.98-08-035, Appendix A, Affiliate Transaction Rules (Rule VII(B)(2) states that "existing" products and services are limited to "those which a utility is offering on the effective date of these Rules." Palo Verde water sales began after the Rules were adopted.)

[601] D.98-08-035, Appendix A, Affiliate Transaction Rules, page 19.

especially in a case where SCE seeks to reclassify revenues previously credited to ratepayers. As explained in D.97-12-088, "nothing in our actions approving this rule predetermines the disposition of these revenues."[602] Furthermore, SCE seeks to assign these revenues to NTP&S retroactively (covering those received since the beginning of 2019) even though it has not yet received Commission approval.

Apart from the process requirements that SCE failed to satisfy, there are four substantive and policy reasons to oppose reclassifying water sales revenues as NTP&S. First, SCE's involvement is entirely passive because the relevant infrastructure is operated by majority owner APS. Given that SCE has "made absolutely no effort related to this transaction", the Commission should decline to transfer any of these revenues from ratepayers to shareholders.[603]

Second, the transaction involves APS (which owns 29.1% of Palo Verde) and its own affiliate (Redhawk) which is owned 100% by APS.[604] Despite being an affiliate transaction, the arrangement is exempt from the Commission's affiliate transaction rules because it involves a non-jurisdictional utility. It is not reasonable to allow SCE shareholders to benefit from a reclassification of revenues associated with an affiliate transaction managed by APS.

The Commission's stated intent for allowing NTP&S revenue sharing conflicts with the facts supporting these first two reasons. As explained in D.99-09-079, the revenue sharing mechanism was to adopted to provide "the utility with incentives to use utility property for other productive purposes without interfering with the utility's operation or affecting service to utility

[602] D.97-12-088, page 77

[603] Ex. TURN-09, page 12.

[604] Ex. TURN-09, page 12.

customers."[605] Since the water sales have been occurring for almost 20 years and are overseen entirely by APS, the reclassification of the transaction as NTP&S would provide no "incentives" to SCE. Additionally, SCE has not shown that failure to adopt NTP&S treatment would affect ongoing water sales, which means that the requested reclassification would merely enrich SCE without changing the use of existing utility property.

Third, SCE's share of costs relating to the water sales are contained in the Palo Verde O&M budget and charged to its ratepayers.[606] Neither SCE nor APS has made a sufficient demonstration regarding the incremental costs associated with water transfer, use, transportation or treatment services. Although SCE claims that the costs for these services (which are charged to SCE ratepayers) are fixed and generate structural surpluses of water available for resale, there is no data supporting this assertion in the application.[607] As noted by TURN witness Marcus, SCE has not provided evidence as to whether "changes were made to the water treatment plant and water distribution system to allow production of excess water or for this specific sale."[608]

SCE provided a generic explanation (lacking relevant cost details) of the arrangement in a data response transmitted to TURN less than one week before the start of evidentiary hearings.[609] The Commission should require a far more comprehensive showing as to whether it is reasonable for Palo Verde to incur annual costs for maintaining large surpluses of treated water that are routinely available for resale. To the extent that such an examination would yield a

[605] D.99-09-070, page 14

[606] Ex. TURN-09, page 13; 4 RT 575: 16-18 (SCE/Champ)

[607] Ex. TURN-042, SCE response to TURN data request 91, Q09.

[608] Ex. TURN-09, page 13.

[609] Ex. TURN-042, SCE response to TURN data request 91, Q09 (dated June 30, 2020)

determination of any incremental costs incurred for this purpose, those costs should be removed from rates and netted against any gross revenues subject to NTP&S treatment.

If SCE is able to demonstrate that all the water purchase, transportation and treatment costs recovered in rates (including those supporting the water sales) are needed to support basic operations at Palo Verde, this fact undermines the claim for NTP&S revenue sharing treatment. As noted by the Commission in D.99-09-070, the adoption of a mechanism providing 70% of gross revenues to shareholders is reasonable if SCE is responsible for bearing some of the associated costs.[610] The assumption that SCE shareholders incur some level of cost was critical to the adoption of a gross (rather than net) revenue sharing mechanism because it "protects ratepayers from significant downside business risk".[611] The settlement agreement between SCE and Office of Ratepayer Advocates adopted in D.99-09-070 explicitly includes this understanding and states that "a sharing mechanism based on gross revenues (rather than net revenues) reduces the level of regulatory oversight required and provides utility customers with benefits even if the overall product or service has negative net revenues."[612]

If there are no "incremental" costs associated with the transaction, there is no possibility of "negative net revenues" and no assumption of any "downside business risk" by shareholders. If no costs are netted against gross revenues received from Redhawk, SCE shareholders would

[610] D.99-09-070, page 24 ("both "passive" and "active" categories are associated with Edison bearing some costs.")

[611] D.99-09-070, Finding of Fact 9 ("The sharing mechanism is reasonable because it allocates gross, as opposed to net revenues, which allocation protects the ratepayers from significant downside business risk, while providing the opportunity for gains over the life of each endeavor the utility makes to utilize an asset.")

[612] D.99-09-070, Attachment A, Settlement Agreement of SCE and ORA on the Revenue Sharing Mechanism for the Utility's Non-Tariff Products and Services, page 3, Agreement Section (B).

realize benefits under any conceivable scenario. In the event that Redhawk ceases all water purchases, all costs would continue to be covered by ratepayers while shareholders would not be subject to any downside risk. This outcome is inconsistent with the intent and purpose of the gross revenue sharing mechanism.

Finally, the Commission should recognize that the longstanding practice of crediting these revenues to ratepayers means that the only impact of SCE's proposed change would be increased costs recovered in rates. This outcome is inconsistent with the Commission's adopted rules requiring that an existing utility asset may be offered on a non-tariffed basis "without adversely affecting the cost….of tariffed utility products and services."[613] There is no dispute that granting SCE's request would result in an increase in the cost of these assets charged to ratepayers.

For these reasons, TURN urges the Commission to reject SCE's proposal to reclassify water sales revenues as NTP&S. If the Commission believes that there may be merit to such reclassification, it should direct SCE to make a separate filing with a showing that complies with the applicable NTP&S rules and can be subject to a thorough review by intervenors and staff.

22.8 Other Issues

23. ENERGY PROCUREMENT

24. ENTERPRISE TECHNOLOGY

24.1 Overview

24.2 Fixed Price Technology and Maintenance

[613] D.98-08-035, Appendix A, Affiliate Transaction Rule VII(C)(4)(c), page 18.

24.3 Software Maintenance and Replacement

24.4 Other Issues

25. OU CAPITALIZED SOFTWARE

26. ENTERPRISE PLANNING & GOVERNANCE (NON-INSURANCE)

26.1 Financial Oversight and Transactional Processing

26.1.1 Vendor Discounts

26.1.2 Participant Credits and Charges

TURN recommended a $2.228 million reduction to Palo Verde participant charges based on a lower O&M recommendation (relative to SCE) that relies on the 2020 APS budget forecast.[614] SCE's rebuttal testimony does not respond directly to TURN's recommendation but instead adopts the Cal Advocates position of switching to a 5-year historical average rather than relying on a forecast of expenses for the test year for the portion of charges relating to pensions and benefits.[615] TURN accepts the resulting estimate of pensions and benefits, which is lower than the proposal outlined in TURN's testimony. The remaining participant charges, relating to Administrative and General Costs assigned to ratepayers in Account 930, will vary with the adopted Palo Verde costs under the SCE and Cal Advocates proposals. However, this variation will be automatically picked up in the Results of Operations (RO) model.

Applying TURN's lower O&M estimate to the calculation of participant charges, with the exception of those subject to the five year average, yields a $0.255 million reduction relative to the figure in SCE's rebuttal testimony.[616] Because the resulting participant charges depend on

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[614] Ex. TURN-09, pages 10-11.

[615] Ex. SCE-17v2, page 13.

[616] Ex. TURN-48, Response to SCE DR 105, Question 3.

the level of O&M spending authorized for Palo Verde (and will be automatically included in the RO model), TURN and SCE still propose different numbers that will be determined by the resolution of disputes over O&M spending. With respect to the approach to calculating participant charges, there are no remaining issues that require resolution by the Commission.

26.2 Legal

26.3 Supply Chain Management

26.3.1 Supplier Diversity & Development

27. INSURANCE

27.1 Liability Insurance (Wildfire)

27.1.1 Based on the Evidentiary Record Developed In This Proceeding, the Commission Should Authorize SCE To Recovery From Ratepayers 50% of the Wildfire Liability Insurance Costs Found Reasonable.

The Commission should authorize rate recovery of 50% of the wildfire liability insurance costs found reasonable for the 2021 test year, based on allocating SCE's insurance costs equally between the utility's ratepayers and shareholders. The risk that a wildfire in SCE's service territory could result in substantial amounts of claims paid is a risk with potential financial consequences for both ratepayers and the utility's shareholders. To the extent the Commission might permit rate recovery of such claims costs in the future, the risk appears to fall on ratepayers. But, as SCE has made exceedingly clear in its Annual Reports (Form 10-K filed with the Securities and Exchange Commission), there is also the risk that the Commission will not allow SCE to recover claims costs on the basis that such costs were not reasonably or prudently incurred or for other reasons.[617] SCE's Chief Executive Officer confirmed this in no uncertain

[617] Ex. TURN-01 Atch 1 -- Edison International and Southern California Edison 2019 Annual Report ("SCE 2019 Annual Report"), p. 108 (Attachment 14, p. 38).

terms during the GRC evidentiary hearings. Since the wildfire liability insurance mitigates the risk of loss for both ratepayers and shareholders, the utility should be required to bear a fair share of the costs of that insurance, and a 50% share is the minimum amount shareholders should bear under the circumstances.[618]

The existence and magnitude of this risk to SCE and its shareholders, and the central role that the utility's wildfire liability insurance coverage plays in mitigating that risk, are both made exceptionally clear in the utility's 2019 Annual Report, submitted to the Securities Exchange Commission in early 2020, from which the following points emerge:

> The liabilities that SCE potentially faces from wildfire-related damages are substantial. As of December 31, 2019, the utility and its holding company Edison International have estimated losses of $4.9 billion on their balance sheet related to the 2017/2018 Wildfire/Mudslide Events. And this figure represents the lower end of the reasonably estimated range of expected potential losses that may be incurred.[619]
>
> To the extent SCE is required to pay uninsured wildfire-related damages, future rate recovery of such costs may be denied if the Commission determines that SCE was not prudent.[620]
>
> SCE's wildfire liability insurance coverage reduces the amount of losses from amounts the utility incurs but may not be able to recover through customer rates. To illustrate, SCE has estimated losses of $4.9 billion related to the 2017/2018 Wildfire/Mudslide Events; when offset with $2.0 billion of expected insurance recoveries and $150 million of expected revenue from FERC customers, a much lower total pre-tax charge of approximately $2.75 billion results.[621] Or as SCE put it, "without the $2 billion of expected insurance recoveries, there would

[618] Ex. TURN-01 (Finkelstein), pp. 5-6.

[619] Ex. TURN-01 Atch 1 -- SCE 2019 Annual Report, pp. 32-33 and 110 (Attachment 14, pp. 28-29 and 40).

[620] *Id.*, p. 38.

[621] *Id.*, pp. 32-33 and 110.

> have been no reimbursements to net against the potential liability, resulting in a higher net charge."[622]

To the extent SCE achieves recoveries under wildfire liability insurance policies, it reduces the amount of uninsured wildfire related damages and, by extension, the amount of risk faced should the Commission deny future rate recovery. Given these facts, the wildfire liability insurance SCE purchases for the 2021 test year must be understood to protect the financial interests of the utility and its shareholders, as well as protecting the interests of SCE ratepayers.

SCE's CEO confirmed the most salient points regarding the role wildfire liability insurance plays in protecting the utility and its shareholders from costs that the utility would not otherwise be able to recover in rates. He agreed that SCE and its shareholders face financial consequences from uninsured wildfire claims, as the Commission could determine that some or all of the costs of such claims should be excluded from rate recovery.[623] And Mr. Payne acknowledged that the 2019 Annual Report, which serves the purpose of informing investors and potential investors so they can make informed decisions about whether to purchase SCE stock, identifies a risk that uninsured losses may not be put into rates should the Commission find the utility did not act prudently.[624] The same risk to shareholders would exist in 2021 and every year that the utility operates going forward, in the event of a covered wildfire event with claims that exceed the amount of insurance coverage.[625]

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[622] SCE Response to PAO-57, Q7 a., as quoted in Ex. PAO-10 (Waterworth), p. 21.

[623] 3 RT 363, ll. 11-19 (Payne/SCE).

[624] *Id.*, at 366, ll. 6-19 and 367, ll. 1-6; and 368, ll. 5-14.

[625] *Id.* at 398, ll. 8-28 and 399, l. 1-6.

The Commission should ignore any SCE attempt to conflate the disallowance of costs resulting from utility imprudence with the separate penalty the Commission may adopt under certain circumstances.[626] These are two distinct outcomes, and the Commission has long rejected the notion that a disallowance of costs based on a determination of utility unreasonableness or imprudence is a "penalty."[627]

In sum, if the costs of claims and other expenses associated with wildfires and related events were certain to be recoverable in rates, it might make sense to assign the full share of reasonable costs of wildfire liability insurance policies to SCE's customers. But given the very clear risk that the costs of claims and other expenses could fall on the utility itself, the Commission should authorize rate recovery of half the cost from ratepayers, and require that the other half be paid by the utility and its shareholders.

27.1.2 The Commission Should Adopt A Forecast of $410.6 Million For The Costs of Obtaining $1 Billion of Wildfire Liability Insurance, While Retaining SCE's Existing Opportunity To Seek Rate Recovery of Above-Authorized Costs Through the WEMA and a Future Showing of Reasonableness.

SCE forecasts $624 million in the 2021 test year as the cost of obtaining approximately $1 billion of wildfire liability insurance coverage. SCE's overall showing in support of its $624 million forecast is remarkably thin and almost casual, particularly in light of the fact that it represents a more than $500 million increase as compared to the forecast the utility put forward

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[626] *Id.*, at 369, ll. 7-13.

[627] D.14-06-007 (Sempra PSEP Decision), p. 32. In rejecting the argument that a regulatory disallowance is a penalty, the Commission stated, "It is quite clear that any costs which may be disallowed in a subsequent proceeding are merely the proper consequences if imprudent actions by the utility and do not constitute a penalty. [¶] In addition to these consequences however, the Commission has the authority and may in fact impose a penalty when the act that was imprudent also breaks a law, a rule, or contract."

in its test year 2018 GRC, and a nearly $400 million increase as compared to the recorded cost for 2018.[628]

SCE's direct testimony includes evidence that arguably demonstrates that the cost to achieve $1 billion of wildfire liability insurance coverage in 2021 will be substantially higher than it was in 2018. But the showing is not adequate to establish the reasonableness of the utility's $624 million forecast (representing a 163% increase over 2018 recorded costs).[629] Most obviously, there is nothing in the testimony that explains in any detail how SCE arrived at the $624 million figure for 2021. As a general matter, the utility states that its broker (Marsh USA Inc., or Marsh) forecasted test year 2021 premiums based on "expected insurance market trends as well as SCE's specific loss record."[630] But the sole supporting document is a "Marsh Premium forecast letter."[631] The "Marsh Premium forecast letter" itself provides only the most minimal information.[632] The letter's entire discussion of the wildfire liability insurance costs is as follows:

> Based upon expected market conditions, Edison's current loss experience and available capacity, Marsh projects Edison's rate change, at the renewal date, as follows:…

General Liability – Wildfire	85% increase for 2019, 10% increase for 2020 and 2021
Wildfire – Property damage	300% to 340% increase for 2019; hold constant for

[628] Ex. TURN-01 (Finkelstein), p. 6; Ex. SCE-06, Vol. 2, p. 45, Figure III-11.

[629] Ex. TURN-01 (Finkelstein), p. 12.

[630] Ex SCE-06, Vol. 2, p. 33.

[631] *Id.*, p. 37.

[632] Ex. TURN-55 (Excerpt of Workpapers for SCE-06, Vol. 2, Book A), p. 96.

2020; 10% decrease for 2021….

> Please keep in mind these projections are based on Edison's current loss experience with no further adverse loss development. These projections also are based on public information shared to date on the 2017 Thomas Fire/Koenigstein Road and 2018 Woolsey wildfire claims. These projections also do not contemplate new claims submitted or catastrophic industry losses.

The remaining workpapers for wildfire liability insurance merely reiterate that SCE's forecast represents the 2018 recorded figure escalated by the percentages obtained from Marsh.[633] During the evidentiary hearings, SCE's witness (a Marsh employee) confirmed that the only other workpapers relevant to the wildfire liability insurance forecast merely presented the 2018 recorded figure, and the figures derived for the 2019, 2020 and test year 2021 forecasts, and calculations of the differences between some of those figures.[634] There was no information in the workpapers that might explain how the 2019-2021 figures were derived, beyond the general assertion that the forecast reflects the 2018 recorded figure, escalated by the Marsh-supplied rates.[635] In addition, the workpapers do not explain how the two separate escalation patterns set forth in the Marsh forecast letter (for "General Liability – Wildfire" and "Wildfire – property damage") were combined to produce a single increase for wildfire liability insurance. Nor do the workpapers describe the manner in which SCE translated the mid-year to mid-year increases provided by Marsh into calendar year increases for purposes of the GRC, or provide the associated calculations.[636]

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[633] *Id.*, pp. 98-102.

[634] 7 RT 870, ll. 3-23; and 872, l. 6 to 873, l. 27 (Jiang/SCE).

[635] Ex. SCE-06, Vol. 2, Bk A E WP, p. 100.

[636] *Id.*, 7 RT 874, l. 10 to 876, l. 19.

In its rebuttal testimony, SCE labeled its direct showing in support of its wildfire liability insurance forecast as "adequate," and cited its reliance on the expert opinion of its insurance broker, consistent with its past practices. The utility also claims its forecasts are "in line with [the] recent actual expenses."[637] But the $624 million that is forecasted for 2021 represents a very substantial increase over the "recent actual expenses," whether one looks at the $236.9 million recorded for 2018, or the $410.6 million forecasted for 2019 – the 2021 forecast is 50% higher than the 2019 forecast, and 163% higher than the 2018 recorded amount. TURN recognizes that SCE's direct showing in support of its liability insurance expense forecast contains approximately the same level of detail as the utility included in its direct showing from prior GRCs.[638] But whatever the utility thought of the adequacy of its showing in support of those forecasts in those GRCs, when it realized it was going to ask for $624 million for 2021, it should have known that a more detailed and better supported showing would be required in order for the Commission to find this forecast reasonable. As the Commission has recognized, "The greater the level of money, risk and uncertainty involved in a decision, the greater the care the utility must take in reaching that decision."[639]

The Commission must conclude that SCE's forecast of $624 million is inadequately supported and therefore cannot be found to be just and reasonable for purposes of setting the authorized revenue requirement for 2021. Instead, the Commission should adopt SCE's forecasted 2019 cost for wildfire liability insurance ($410.6 million) as the forecast for the 2021 test year. Adopting a $410.6 million forecast for the test year would provide SCE a very

[637] Ex. SCE-17, Vol. 2, p. 26.

[638] Ex. TURN-01 (Finkelstein), p. 15.

[639] D.18-07-025 (SDG&E WEMA), p. 6.

substantial increase of $173 million or 73% over the 2018 recorded figure ($236.9 million). And under the existing ratemaking mechanism for wildfire liability insurance, should SCE's actual costs exceed the adopted forecast, the utility will have the opportunity through the WEMA to seek rate recovery of those actual costs to the extent the utility is able to establish their reasonableness.[640]

27.1.3 The Commission Should Decline To Take Any Position On Catastrophe Bonds, Self-Insurance, Or Any Other "Alternative Risk Transfer Instruments," As SCE's Showing On Such Topics is Inadequate to Establish Reasonableness.

SCE's direct testimony purported to reserve to the utility "the option to self-insure" against wildfire liability risk, should the utility determine that the cost of purchased liability insurance "is excessive relative to the risk exposure," and if such an approach is "supported by actuarial analysis."[641] The utility also suggested that it might seek to use "catastrophe bonds" as another example of an "alternative risk transfer instrument" it may rely upon to obtain the target level of liability coverage.[642] The Commission should decline to say anything in this decision that might later be interpreted as a determination of the merits (or lack thereof) for any alternative risk transfer instrument. Any such determination needs to consider in full the potential costs and benefits of achieving "insurance" in this form. SCE's showing here does not

[640] In Sections 34 and 34.3, TURN explains why the Commission should reject SCE's proposal for a new Risk Management Balancing Account that would enable the utility to recover in rates its recorded costs for wildfire liability insurance, without being required to demonstrate the reasonableness of above-authorized costs. Instead, the Commission should continue to permit SCE to record above-authorized costs for wildfire liability insurance in its existing Wildfire Expense Memorandum Account (WEMA).

[641] Ex. SCE-06, Vol. 2, p. 41.

[642] *Id.*, p. 39.

establish the reasonableness of these options as they might be applied to the utility's circumstances. But under SCE's proposed ratemaking, with costs recorded in the Risk Management Balancing Account (RMBA) and subject only to a compliance audit level of review in a future ERRA, it is not clear if or when SCE's decisions to rely on such alternative instruments would ever be meaningfully reviewed. Therefore, the Commission should state that, whether it maintains the current WEMA for tracking and reviewing SCE's wildfire insurance costs or adopts some other ratemaking outcome going forward, SCE will continue to bear the burden of demonstrating the reasonableness of any alternative risk transfer instrument it might choose to deploy in lieu of or in addition to traditional third party insurance.

For catastrophe bonds, SCE's direct testimony in the GRC simply referred to this type of instrument as an option it might pursue, with a footnote stating that such bonds "are a capital markets instrument used to provide protection against perils such as earthquakes and wildfires."[643] There is no further detail about how such bonds would work as a potential substitute for "traditional insurance," how ratepayers might benefit from SCE using such an instrument, the potential costs and risks to both ratepayers and the utility itself, or anything that might permit the Commission to assess whether this is a reasonable alternative under the circumstances.[644] Although SCE objected to TURN's characterization of such bonds as "new and untested," the utility was unable to present any evidence demonstrating that the Commission had previously assessed the reasonableness of any California utility relying on such instruments in a utility context.[645] Nor did the utility describe how the Commission would be able to

[643] *Id.*, p. 39, fn. 31.

[644] Ex. TURN-01 (Finkelstein), pp. 16-17.

[645] Ex. SCE-17, Vol. 2, pp. 26-27.

determine the cost-benefit of bond transaction from the perspective of SCE's ratepayers, or assess whether a catastrophe bond is less expensive than traditional insurance or other options.[646] SCE may genuinely believe that it "would only engage in such a transaction if it could fill the capacity at a lower cost than market-priced insurance and reinsurance or if no capacity were available from traditional markets."[647] But that is not a sufficient basis for a finding of reasonableness at this time.[648] Therefore, the Commission should make clear that nothing in this decision serves to authorize SCE to rely on a catastrophe bond for wildfire liability purposes, and that if the utility chooses to use such an instrument, it will need to demonstrate the reasonableness of that approach in a subsequent reasonableness review.

The Commission should have similar concerns about SCE claiming to reserve to itself the option to "self-insure." The determination of whether self-insurance would be a cost-effective alternative to insurance purchased from a third party depends on an actuarial analysis that has not yet been presented to the Commission.[649] Furthermore, it relies on a determination of the "probability of loss" that itself is a concept not yet presented to or vetted by the Commission in the wildfire liability insurance context.[650] And the reasonableness of self-insurance as an option would likely need to consider not only the cost to ratepayers of the insurance itself, but also the potential cost of wildfire claims covered by that insurance. After all, rather than such claims

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[646] Ex. TURN-63 (Responses to TURN DR 97), p. 6 (Response 9(a)).

[647] *Id.*, p. 7 (Response 9(b)).

[648] In TURN's view, it provides further reason to reject SCE's proposed balancing account ratemaking treatment and its elimination of reasonableness reviews. *See* Section 34.3, below.

[649] Ex. SCE-06, Vol. 2, p. 41; Ex. TURN-63 (Responses to TURN DR 97), p. 8 (Response 10(b)).

[650] Ex. TURN-63 (Responses to TURN DR 97), p. 10 (Response 10(f)).

being paid by a third party, SCE would seem to be proposing that they be paid by ratepayers if they fall within the "self-insurance" coverage. Thus, the reasonableness and ratemaking issues would be very different for self-insurance than are implicated by the third-party insurance for which SCE seeks rate recovery here. For that reason, the Commission should make very clear that its decision here does not address self-insurance in any way, and that such determinations would be made in future proceedings, after SCE has made an adequate showing of the reasonableness of self-insurance as an option for wildfire liability insurance.

27.2 Liability Insurance (Non-Wildfire)

27.3 Property Insurance

27.4 Proposed Accelerated Recovery of Wildfire Insurance-Related Regulatory Asset

The Commission should deny SCE's request to increase its test year 2021 revenue requirement by $19 million to accelerate recovery of capitalized wildfire insurance costs in order to comply with a FERC ruling that makes clear no such action is necessary.

SCE currently recovers as capitalized costs a portion of the wildfire liability insurance costs authorized in the utility's test year 2015 and 2018 GRCs. These costs are recorded as a regulatory asset with a forecasted balance of approximately $95 million at the start of the 2021 test year; the associated rate recovery is expected to occur over a 23.4 year period. Maintaining the *status quo* would result in SCE recovering in rates approximately $13.3 million in 2021, $12.9 million in 2022, $12.5 million in 2023, and $12.1 million in 2024 for these costs authorized in the 2015 and 2018 GRCs.[651]

[651] Ex. SCE-17, Vol. 2, Appendix A, pp. A-1 to A-2 (Supplemental Response to Data Request TURN-SCE-038, Question 13.b.)

SCE here seeks to change the ratemaking treatment in order to accelerate rate recovery for the full $95 million over the test year 2021 GRC cycle, based on FERC guidance that SCE interprets to mean such costs should be treated as an expense.[652] However, rather than treat the $95 million as an expense to be amortized over this shorter period, SCE seeks to continue capitalization ratemaking treatment, thereby earning a return on the unrecovered portion throughout the GRC cycle. Thus, under SCE's approach, the utility would collect a total of $114.8 million over a four-year 2021 GRC cycle.[653] And the authorized revenue requirement would be higher by approximately $19 million in 2021 than it would be if the *status quo* were maintained.[654]

There is no dispute that SCE would ultimately recover the $95 million of previously authorized wildfire insurance costs were the status quo to be continued. The revenue requirement increase sought here is solely due to SCE's request to adopt different ratemaking that would accelerate that recovery.

SCE claims that its proposed accelerated recovery is appropriate because the utility obtains wildfire liability insurance on a "stand-alone" basis rather than under policies providing combined coverage. For such "stand-alone" coverage, SCE contends, "The Federal Energy Regulatory Commission (FERC) requires expensing, not capitalizing, stand-alone wildfire

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[652] Ex. SCE-6, Vol. 2, pp. 46-48.

[653] Ex. SCE-17, Vol. 2, Appendix A, p. A-2. For a three-year GRC cycle, consistent with the analysis in SCE's application and direct testimony, the total capitalized recovery would be $110.1 million for the $95 million of insurance costs. *Id.*

[654] *Id.* Comparing the "23.4-year recovery" (the *status quo*) with the "4-year recovery" indicates a revenue requirement increase of $18.9 million for 2021, $17 million for 2022, $15 million for 2023, and $13.1 million for 2024. Significantly larger annual differences for 2021-23 result if the comparison is to the "SCE Application" figures, although the total recovery if a three-year period is used is $110.1 million.

insurance premiums."[655] The Public Advocates Office (Cal Advocates) opposes SCE's proposed acceleration, arguing that the Commission is not obligated to follow FERC accounting guidance, and SCE has provided no evidence of any material benefit to its ratepayers from the proposed change.[656]

TURN's prepared testimony supported the staff's position, and added that the FERC authority SCE cited for its position said something very different than the characterization thereof that appeared in SCE's direct testimony. There is nothing in the cited FERC order that "requires expensing, not capitalizing, stand-alone wildfire insurance premiums." To the contrary, the FERC ruling explicitly provides that if such wildfire insurance costs "are recoverable in future periods in CPUC-jurisdictional rates, SDG&E may defer the costs."[657] In this way, FERC specifically accommodates continued capitalization of CPUC-jurisdictional amounts where permitted by the CPUC. In discovery, SCE conceded that even after the cited order, FERC would permit SCE to defer rate recovery of the previously authorized wildfire liability insurance amounts.[658]

SCE's rebuttal testimony first repeats the assertion that "[FERC] requires expensing, not capitalizing, wildfire-related insurance premiums," but then acknowledges "[t]he Commission is not bound by FERC's guidance" and "the FERC Order also recognized that the CPUC may reach

[655] Ex. SCE-6, Vol. 2, p. 47.

[656] Ex. PAO-10 (Waterworth), pp. 23-24.

[657] Ex. TURN-01 (Finkelstein), pp. 21-22, *citing* Federal Energy Regulatory Commission Order On Compliance Filing, issued August 3, 2012, to San Diego Gas & Electric Company. Docket No. ER11-4318-001, p. 7. The FERC order appears as an attachment in SCE's rebuttal testimony – Ex. SCE-17, Vol. 2, Appendix B.

[658] *Id.*, p. 22, *citing* SCE Response to TURN DR-38, Q. 13(c) and (d) (Ex. TURN-01-Atch, Attachment 7, pp. 10-11).

a different conclusion on already authorized insurance premiums."[659] Even if SCE is correct that it cannot unilaterally maintain the *status quo* in light of FERC's directives,[660] it could have asked the Commission to maintain its current ratemaking treatment, thus avoiding creating the appearance of a need for a $19 million increase to its test year 2021 revenue requirement. Instead, SCE insists that the Commission should permit it to change the ratemaking of the costs authorized in the 2015 and 2018 GRCs in order to achieve consistency with the proposed treatment for costs in 2021 and beyond in this proceeding, and to avoid having inconsistent accounting and ratemaking treatment.[661]

The Commission should deny SCE's request due to its lack of support and its inappropriateness in the current environment, where it would cause an extraordinarily high revenue requirement increase to be even higher. The FERC ruling that SCE relies upon specifically provides that the expensing approach need not apply where the Commission has provided for recovery in future periods in CPUC-jurisdictional rates. SCE acknowledges that the Commission has provided for such recovery. And while there may be some benefit from having consistent accounting and ratemaking treatment across periods and jurisdictions, there are also often conditions that warrant the Commission adopting different treatment than strict application of FERC guidance would produce. Where, as here, the change in ratemaking treatment would increase the test year 2021 revenue requirement by $19 million, the Commission must require more than vague assertions of improved efficiency and reduced inconsistency as justification for the requested change. This is especially true where the requested increase contributes to an

[659] Ex. SCE-17, Vol. 2, pp. 32 and 34-35.

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

[661] *Id.*, pp. 34 and 36.

overall requested increase in excess of $1.288 billion.[662] In this GRC, it is especially important for the Commission to limit the authorized increases to requests tied to matters that are more essential to the utility's operations. Accelerating rate recovery of past insurance expenditures does not rise to that level.[663]

28. EMPLOYEE BENEFITS

28.1 Overview

The Commission should adopt TURN's adjustments to SCE forecasts for Executive Compensation (including long-term incentives) and Benefits, which are summarized in the following table.

Summary of Base Year (Recorded) and Test Year (Forecasted – SCE and TURN) Executive Compensation and Benefits Recommendations (1,000s of 2018 dollars)[664]

		2021 Forecast		
Cost Category	2018	SCE	TURN	SCE > TURN
Executive Compensation	$ 16,346	$ 18,133	$ 4,803	$ 13,329

[662] Ex. SCE-52A 2E (SCE Update Testimony), p. 1.

[663] Should the Commission decide SCE's accelerated recovery proposal has merit, a position TURN vigorously disputes, it should require SCE to amortize the remaining $95 million as an expense, rather than as a capitalized amount with a reduced recovery period. If the Commission accepts SCE's argument that it must treat these amounts as an expense pursuant to FERC guidance, that expense treatment should start at the beginning of the 2021 test year. Ex. TURN-01 (Finkelstein), p. 23. Recovery of the $95 million as an expense over a four-year GRC cycle results in an annual recovery of approximately $23.75 million, an $8.45 million reduction from the $32.2 million SCE would collect under its four-year capitalized recovery. Ex. SCE-17, Vol. 2, Appendix A, p. A-2.

[664] See Section 28.4 for Executive Compensation, Section 28.5 for LTIP, and Sections 28.2 & 28.3 for Executive Benefits. Ex. TURN-04-E (Jones), p. 25. (Revised clean version of table only addressing executive compensation, LTIP and executive benefits.)

Executive Compensation (Long-Term Incentive Program)	$ 8,130	$ 11,602	$ -	$ 11,602
Executive Benefits	$ 14,445	$ 15,542	$ 13,166	$ 2,376
Total	**$38,921**	**$45,277**	**$17,969**	**$27,307**

The Commission should also adopt TURN's adjustments to SCE's forecast for its Short-Term Incentive Program, as summarized in the following table and addressed in Section 28.6 below.

TURN 2021 STIP Recommendation[665]

	2018 $ 000s		
	Edison Forecast	TURN Recommendation	Difference
Edison STIP at 20.9% of Labor	$180,907		
Maintain STIP at 12.11% of Labor		$103,519	($77,388)
---Measure Reductions---			
Financial Measure: 30%		($31,056)	($31,056)
Lobbying/influence: 20%		($20,704)	($20,704)
TURN Recommendation		$51,759	($129,148)

28.2 Executive Benefits (Non-Service)

SCE forecasts $15.542 million of expenses for Executive Benefits,[666] $2.376 million of which is for employees in positions of Vice President or higher after removing the cost of seven named SCE officers to comply with SB 901.[667] The benefits provided include the Executive Retirement Plan and other benefits not included in the rate request due to their negligible cost to SCE. The

[665] The details of TURN's STIP proposal are addressed below in Section 28.6.

[666] Ex. SCE-06, V3, P1, p. 136: 21-23.

[667] Ex. TURN-04-E (Jones), p. 40: FN 101, referencing SCE's response to TURN DR 76-2. This amount is allocated at $1.866 million to non-service cost and $510,000 to service cost, according to the data response.

Executive Retirement Plan is a non-qualified pension plan that provides benefits that executives cannot receive in the qualified SCE Retirement Plan as a result of compensation and payout limits imposed by the Internal Revenue Code (IRC) on that plan.[668]

While SCE removes Executive Compensation for Rule 3b-7 officers, TURN recommends that the Commission remove Executive Benefits for all employees in positions of Vice President or higher from the GRC forecast, resulting in a reduction of $2.376 million from SCE's forecast, corresponding to a recommended forecast of $13.166 million. The arguments and reasoning for this recommendation correspond to those in Section 28.4 below regarding Executive Compensation.

28.3 Executive Benefits (Service)

See Section 28.2 above, TURN recommends that the Commission remove Executive Benefits for all employees in positions of Vice President or higher from the GRC forecast, resulting in a reduction of $2.376 million from SCE's forecast. This amount is allocated at $1.866 million to non-service cost, and $510,000 to service cost.[669]

28.4 Executive Compensation

SCE forecasts $18.133 million in expenses for Executive Compensation, including salaries and short-term incentives, non-labor expenses, and outside services after removing the cost of seven named SCE officers to comply with its interpretation of Senate Bill (SB) 901.[670] The $18.133 million forecast is composed of a labor forecast of $8.493 million, which is mainly

668 Ex. SCE-06, V3, P1, p. 134: 5-9.

669 Ex. TURN-04-E (Jones), p. 40: FN 101, referencing SCE's response to TURN DR 76-2.

670 Ex. SCE-06, V3, P1, p. 50: 12-17.

for SCE executive compensation,[671] including one Shared Officer and $9.639 million for non-labor expense, which includes compensation and benefits costs for all but one of the Shared Officers and EIX Executives that SCE allocates to ratepayers.[672]

The Commission should adopt TURN's primary recommendation, to remove most of the labor forecast, $8.224 million[673] and the portion of non-labor expense that is composed of the Shared and EIX officers forecast, consistent with Senate Bill (SB) 901. To the extent that the Commission does not adopt TURN's primary recommendation, TURN's secondary recommendation regarding the Executive Incentive Program (EIC) program for executives is addressed below in Section 28.4.4, and recommends a reduction to the target cost of the EIC's financial goal and of lobbying goals on the basis that achievement of the goals primarily benefits shareholders. The deduction, 50% of SCE's request, totals $1.133 million, for a total reduction of $1.133 million

28.4.1 Compensation for All Officers with Titles of Vice President and Above Should be Removed from SCE's Forecast Pursuant to SB 901.

SB 901 was enacted in 2018 and revised Section 706 of the Public Utilities Code, prohibiting all investor owned utilities from recovering "any annual salary, bonus, benefits, or

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[671] SCE records one of the Shared Officer positions to labor in Figure III-9—the test-year forecast for the position is $261,756. (Ex. TURN-04 (Jones), p. 27: FN 60, referencing TURN DR 11-10 (Revised) (included at Ex. TURN-04-Atch 1 (Jones), p. 41). The forecast also includes $269k for Executive Labor Support, which TURN does not remove.

[672] *Id*. The SCE-allocated compensation forecast for Shared Officers is $2.652 million ($2.390 million for non-labor and $267K for labor) and for EIX Executives is $2.714 million Shared Officers (Calculated from TURN DR 27-3, Attachment CONFIDENTIAL_TURN-SCE-027 Q03 EIX and Shared Officers Att 1), for a total of $5.105 million (Ex. TURN-04-E (Jones), p. 40).As noted in the footnote, above, SCE records the cost of one of the Shared Officer positions to labor.

[673] TURN does not remove the portion of the labor forecast for Executive Support staff.

other considerations for any value, paid to an *officer* of an electrical corporation."[674] As TURN explained in testimony, while SB 901 provides guidance as to types of remuneration that constitutes "compensation", it does not define "officer" and does not limit the definition of "officer," either.[675]

SCE relies on CPUC Resolution E-4963 to establish the basis for which executives' compensation it will remove from rates (pursuant to SB 901), based on the fact that the company established a memorandum account for executive-officer compensation pursuant to Resolution E-4963 and its claim that the memorandum account tracks officer compensation and benefits "on a going-forward basis."[676] In so doing, the company relies on the Commission's understanding of the definition of officer as set forth in the Securities and Exchange Commission's (SEC) Rule 240.3b-7 to remove seven named officers in its attempt to comply with SB 901.[677] This interpretation is too narrow to comport with the intent of SB 901, because it focuses only on SCE officers that are at the Senior Vice President level and above, despite the fact that SCE's Vice Presidents are executives in charge of large sections of SCE's business. As explained in TURN's testimony, SCE's organizational chart indicates that while many of the vice presidents within the structure lead units that are below the overarching units that are the charge of Senior Vice Presidents (i.e., analogous to the "principle business unit" as used in the Rule 240.3b-7

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674 Public Utilities Code (PUC) Section 706 (*emphasis* added).

675 Ex. TURN-04 (Jones), p. 28: 18-20.

676 Ex. SCE-06, V1, P1, p. 25: 9-17.

677 As discussed below, SCE relies on its interpretation of CPUC Resolution E-4963 to invoke Rule 240.3b-7. Consistent with SCE's Rebuttal, we use "Rule 240.3b-7" when referring to the Securities and Exchange Act and "Rule 3b-7" when referring to the "officers" at issue in Rule 240.3b-7 of the Securities and Exchange Act.

definition), the vice presidents are clearly in charge of large portions of SCE's business—perhaps what Rule 240.3b-7 may designate as a "division".[678]

28.4.1.1 A Departure from SCE's Interpretation of the Definition of "Officers" Used in Resolution E-4963 for the Purposes of SB 901 Implementation is Reasonable and Consistent with the Intent of SB 901.

SCE claims that Resolution 4963-E provides "governing authority" supporting its position regarding the definition of officer, not TURN's definition.[679] SCE concludes that TURN "unilaterally" subverts what SCE asserts to be affirmative Commission precedent on the matter.[680] There are several issues with respect to the definition of "officer," as established in Rule 240.3b-7 of the Securities Exchange Act, and implications with respect to the intent and application of SB 901 that are not fully explained or potentially considered within Resolution E-4963. TURN respectfully requests that the Commission consider afresh the definition of "officer," in regards to the removal from rate recovery pursuant to SB 901. Such consideration certainly does not constitute "legal error"[681] as SCE contends. Indeed, the Commission is careful

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[678] Ex. TURN-04 (Jones), pp. 31 (starting at line 23) – 32 (through line 2), referencing SCE's 2018 organizational chart in the response to MDR 20-11 (Ex. TURN-04-Atch 1 (Jones), pp. 48-67. Furthermore, the description of some of SCE's VPs shows substantial oversight of utility operations. For example, while the position of VP of Distribution reports to the SVP of Transmission & Distribution (Ex. TURN-04 (Jones, referencing MDR-20-11 – Org Charts Jan 2018 3 of 3, attached to MDR 20-11 (Ex. TURN-04-Atch 1, p. 51), the current occupant is still responsible for all aspects of electrical and civil design, construction, maintenance and inspection of the overhead and underground distribution network at SCE, as well as material oversight, vegetation management and all associated field accounting activities (Ex. TURN-04 (Jones), p. 32: FN 77, referencing the description of VP Ferree at www.edison.com/home/about-us/leadership/southern-california-edison-leaders/gregory-m-ferree.html).

[679] Ex. SCE-17, V3, pp. 41-42: 13-21 & 1-22.

[680] *Id.*, at p. 42: 7-8.

[681] *Id.*, lines 11-12.

to state within the Discussion section of Resolution E-4963, that "officer" shall be determined by Rule 240.3b-7 "[f]or the purposes of the memorandum accounts,"[682] implying that the Commission does not necessarily intend for the definition to apply in all circumstances nor to endure on an on-going basis.[683]

Not only was Resolution E-4963 adopted to track *interim* costs—indeed, the Commission narrowly focused the resolution to track interim officer compensation "so that such amounts may be refunded to ratepayers through future proceedings,"[684] contrary to SCE's misleading assertion that the memorandum accounts should apply in "future proceedings".[685] SCE's proposed interpretation of the Resolution appears to be at odds with the spirit of SB 901, and direction that the Commission is moving in other Commission proceedings.[686] In any case, it was SCE who, without offering to the Commission the impact the use of the rule may have or discussing the spirit of SB 901, introduced the use of a Federal definition of "officer" that pertains to securities law in Resolution E-4963.[687] Therefore, TURN's position in this case does not constitute a "unilateral" expansion of the definition of "officer" or subversion of established Commission precedent, or any purported "governing authority" conveyed by Resolution E-4963.

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[682] CPUC Resolution E-4963, p. 4.

[683] Note that the Sempra Utilities both recognize that the definition of officer as consistent with Rule 240.3b-7, is only for the purposes of the OCMA in their Advice Letters establishing the OCMA, SoCalGas Advice Letter 5399, p. 2; SDG&E Advice Letter 3324-E/2728-G, p. 2.

[684] Resolution E-4963, Finding Number 6.

[685] Ex. SCE-17, V3, p. 44: 1-2.

[686] See expanded discussion below.

[687] CPUC Resolution E-4963, p. 6.

SCE's Direct Testimony states, "Resolution E-4963 defines "officer" as those employees of SCE in positions with titles of Vice President or above *who are* Rule 3b-7 officers,"[688] which is not a verbatim quotation and is at odds with the company's facsimile of the Resolution in its Rebuttal Testimony, in which it defines "officers" to be "employees in positions with titles of Vice President or above, *consistent with* Rule 240.3b-7."[689] This difference is instructive, as noted in TURN's testimony[690] – the Commission's intent with the latter, correct version of Resolution E-4963, could be interpreted simply as the inclusion of <u>all</u> officers that are at the level of Vice President or above, *is* consistent with Rule 240.3b-7. The exact language of the Resolution does not specify that officers have to be considered by the Securities and Exchange Commission to be Rule 240.3b-7 officers—complete with policy-making functions relevant to *securities law*—in order for SB 901 to apply.

Finally, SCE's reference to Energy Division's January 29, 2019, approval of SCE's Advice Filing is not compelling, given that Energy Division does not seem to parse the potentially separate significance that SCE attaches to Rule 240.3b-7 or address the spirit of SB 901. It is instructive to note that SCE mis-quoted the Commission's finding from Resolution E-4963 in its Advice Filing 3927-E, in the same way that it does in its Direct Testimony, stating that the Commission directed IOUs to exclude positions "of Vice President or above who *are* Rule 3b-7 officers of SCE,"[691] which is not the language from the Resolution,[692] which states,

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[688] Ex. SCE-06, V3, P1, p. 25: FN 35 (*emphasis* added).

[689] *Id*., p. 41: 17-19 (*emphasis* added).

[690] Ex. TURN-04 (Jones), p. 30: 4-17.

[691] Ex. SCE-17, V3, p. A-103, FN 2, which includes p. 1 of Advice 3927-E, dated December 21, 2018.

[692] CPUC Resolution E-4963, p. 8.

"officer" means employees with "titles of Vice President or above, consistent with Rule 240.3b-7". It is entirely possible that Energy Division was misled by SCE's misrepresentation of the Resolution's language. As will be discussed in greater detail below, it is also instructive to note that the Commission, through D.19-09-051, disallowed *all* of the Sempra Energy Utilities' (SEU) compensation for officers at the level of Vice President or higher *after* SCE's Advice Filing to Energy Division, which indicates the Commission's preference going forward.

In addition to the preceding material, consideration of AB 1266 is germane to uncovering the Legislature intent for SB 901 and further consideration of Commission actions in other proceedings fleshes out its intent in developing "governing authority" on this issue. These considerations are presented below.

28.4.1.2 The Commission Should Consider the Predecessor to SB 901: Assembly Bill (AB) 1266.

As explained in Exhibit TURN-04, AB 1266—SB 901's predecessor regarding PUC 706—prohibited recovery of an officer's compensation in excess of $1 million in cases for which an IOU violates a federal or state safety regulation with respect to the plant and facility of the utility and, as a proximate cause of that violation, ratepayers incur a financial responsibility in excess of five million dollars ($5,000,000).[693] As with SB 901 after it, AB 1266 does not explicitly define "officer", nor does AB 1266 also limit the meaning of "officer" in the same way as Rule 240.3b-7.[694] Given that the California Legislature did not redefine "officer" with SB 901 and that the revised version of PUC 706 established by SB 901, "replaced" the version of PUC

[693] Ex. TURN-04 (Jones), p. 32: 20-22.

[694] Ex. TURN-04 (Jones), p. 33: 2-5.

706 created by AB 1266,[695] it can be inferred that the legislature intended a definition that is consistent with the one in AB 1266—one that is effectively more expansive than the one provided by the Securities Exchange Act Rule 240.3b-7, as illustrated below.

AB 1266 and subsequent utility behavior provides insight into the intent of the legislature with AB 1266 and CPUC, pursuant to PUC 706. AB 1266 required that "all authorized executive compensation to be placed in a balancing account, memorandum account, or other appropriate mechanism so that this section can be implemented without violating any prohibition on retroactive ratemaking." Pursuant to this requirement, for its 2018 GRC request, SCE placed all executive officer compensation in a memorandum account without distinguishing between Rule 240.3b-7 and non-Rule 240.3b-7 officers,[696] and the Commission did not object. Instead of addressing this relevant point regarding the intent of the legislature and the spirit of SB 901, and the Commission's interpretation of preceding legislation, SCE side steps the issue and insipidly states that SB 901 supersedes AB 1266,[697] which fails to address TURN's point entirely.

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[695] Ex. TURN-04 (Jones), p. 33: 4-6, referencing Senate Rules Committee, SB 901 Senate Floor Analyses, p. 9, 8/31/18, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB901, as noted in FN 80.

[696] Ex. TURN-04 (Jones), p. 34:14-16, referencing SCE's 2018 GRC, as noted in FN 81; Exs. SCE-06, V1, p. 25:20-25, incl. FN 28; and SCE-09, V1, p. 30:7-13.

[697] Ex. SCE-17, V3, p. 47: 17. Moreover, SCE states (Id., lines 17-19), "…[I]n Resolution E-4963, the Commission clarified that utilities were not even required to open any officer compensation memorandum accounts in conformance with the now-superseded AB 1266." However, it is not true that SCE did not have to open a memorandum account for AB 1266. Rather, it is simply the case that the Commission require through the issuance of Resolution E-4963 the opening of memorandum accounts in response to SB 901. This is not a reason to exclude the similarities between AB 1266 and SB 901 and the Commission's response to the law that preceded SB 901 when from consideration of Legislature intent and the spirit of SB 901 in the instant proceeding.

28.4.2 There is not Clear Commission Precedent Regarding the Definition of Officer Under SB 901 but the SEU 2019 and PG&E 2020 GRCs Are Instructive.

This is the first General Rate Case, in which the issue of which executives qualify as an Officer under SB 901 will be decided by the Commission. In the PG&E 2020 GRC, the definition of an officer was not an issue because PG&E excluded the entire amount of its executive compensation forecast from the GRC in its 2020 GRC filing.[698]

The Sempra Energy Utilities (SEU) 2019 GRC was litigated before SB 901 was enacted, but the Decision was issued after SB 901 took effect. Given the timing, the Commission determined it was not necessary for SDG&E and SoCalGas to remove the officer compensation costs but did acknowledge the scope of the implementation of SB 901, stating:

> "Because the above events took place at a time when evidentiary hearings in these GRCs had already been concluded and all active parties had already filed opening and reply briefs in support of their final positions in the proceedings, we find that it would not be prudent and will cause unnecessary delay to the prejudice of all parties, ratepayers, the public, and the regulatory process, to require SDG&E and/or SoCalGas to revise their testimonies in order to extract the portions of costs that pertain to officer compensation and benefits as these costs are typically embedded in multiple costs and forecasts presented throughout the GRC. For example, costs centers containing officer compensation and benefits within the definition of the revised Section 706 such as a Chief Executive Officer (CEO), President, or Vice President (VP) will also include salaries and benefits of staff and other support personnel for that working group as well as non-labor costs. *This would be true even for cost centers that are titled CEO or Vice President of a particular division, department, unit, or working group*."[699]

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[698] Ex. TURN-04 (Jones), p. 36: 3-4 & FN 90, referencing PG&E 2020 GRC, Ex. PG&E -08, p. 1-3:21-25 (states: "PG&E is not seeking recovery of executive compensation in this case. Pursuant to Senate Bill 901, PG&E has adjusted its 2020 forecast to remove officer compensation and benefits as of September 2018.[footnote omitted] Those adjustments are shown in the workpapers for each impacted plan and a summary is provided 25 in the workpapers to Chapter 4A of this exhibit") and WP 4A-1:FN [a] (states: "Please note, this workpaper shows the removal of approximately $7.7 million of compensation and benefits associated with SEC Rule 240.3b-7 officers. PG&E will remove an additional, approximately $13 million in compensation for other officers and will update its RO and this workpaper accordingly.").

[699] D.19-09-051, pp. 25-26 (Emphasis Added).

The final sentence indicates the Commission is inclined to include all Vice Presidents in the definition, even those that are merely in charge of a *working group*. In Decision 19-09-051, the Commission then removed costs "that are entirely made up of officer compensation and benefits", from the Sempra Utilities' GRC forecast.[700] This includes the entire short-term (called Incentive Compensation Plan, or "ICP" by the Sempra Utilities) and long-term incentive plan (LTIP) forecasts for officers, without exclusion for non-Rule 240.3b-7 officers.[701]

28.4.3 Shared Officers and EIX Executives that are Primarily Allocated to SCE Should be Included in the Executive Compensation Forecast Exclusion under SB 901.

The Commission should remove the entire SCE-allocated compensation forecast for Shared Officers and EIX Executives, $5.105 million.[702] Resolution E-4963 did not expressly address the issue of Shared Officer compensation under PUC 706. Regardless of how the

[700] *Id.* at p. 26.

[701] *Id.* at p. 540. See also Ex. TURN-04 (Jones), p. 35, FN 88: "TURN assumes that the Commission removed all officer ICP forecast—i.e., not just the Rule 240.3b-7-disclosed officers—from the Sempra Utilities' GRC based on the following: The decision states, "Executive ICP are awarded to SoCalGas and SDG&E executives and are no longer recoverable from ratepayers pursuant to Pub. Util. Code § 706. Amounts corresponding to Executive ICP of $3.410 million for SoCalGas and $4.020 million for SDG&E are therefore excluded." The $3.410 million and $4.020 million that the Commission removed from the SoCalGas and SDG&E ICP forecasts, respectively, in the 2019 GRC is exactly equivalent to the companies' ICP forecasts in the 2019 GRC (see Exs. SCG-30 and SDG&E-28, p. DSR-18:tables DSR-11 and DSR-12)). … Regarding LTIP, the decision states, "Pursuant to Pub. Util. Code § 706, ...[LTIP awards] are no longer recoverable from ratepayers and the requested amounts of $10.029 million for SoCalGas and $8.570 million for SDG&E are therefore excluded from the adopted forecast." The $10.029 million and $8.570 million that the Commission removed from the SoCalGas and SDG&E LTIP forecasts, respectively, in the 2019 GRC is equivalent to the companies' LTIP forecasts in the 2019 GRC (see Exs. SCG-30 and SDG&E-28, p. DSR-21: tables DSR-13 and DSR-14)."

[702] Ex. TURN-04-E (Jones), p. 40.

Commission decides this issue as it pertains to the SCE-allocated EIX Executives, TURN recommends that the Commission remove the compensation for Shared Officers (i.e., \$2.652 million) on the basis that the portion of the Shared Officer costs that are allocated to SCE are based on the fact that such officers are employed by SCE, which is by definition an electric utility. For example, the Senior Vice President of Human Resources at SCE is shared with EIX[703] – it is not reasonable to expect that SCE would not require a Human Resources executive if it were not held by EIX.

TURN acknowledges that Resolution E-4963 declined to adopt the recommendation by both SCE and the Utility Consumers' Action Network (UCAN) to include *holding company executives*' compensation within utilities' officer compensation memorandum accounts on the basis that SB 901 only requires removal for electric-company executives. However, TURN believes that there are more facts to consider than either SCE[704] or UCAN[705] provided in

[703] Ex. SCE-06, V3, P1, p. 51: 7-11

[704] By suggesting that it only need to exclude Rule 3b-7-officer compensation, SCE simply intended to extend the rate-recovery exclusion to officers of EIX who were also Rule 3b-7-defined—as opposed to EIX officers that were not Rule 3b-7 officers (see Comments of Southern California Edison Company on Draft Resolution E-4963 (November 9, 2018), p. 1). The explanation therefore was devoid of any discussion of SCE's ability to operate as a stand-alone utility without the services provided by EIX Executives, the fact that as the primary affiliate much of the EIX officer efforts are directed toward SCE, or any allocations from EIX Executives between EIX and SCE.

[705] UCAN's comments on Draft Resolution E-4963 simply stated that "the contribution of officers of the holding company on the day-to-day performance of their subsidiary investor-owned utilities is attenuated because of the corporate holding company structure[and that a]s a result it is difficult to demonstrate how holding company officers contribute to the day-to-day operations of their subsidiary utilities[, and]…the Commission should [therefore] extend the prohibition inherent in Pub. Util. Code section 706 (a) & (b) to the officers of the utility holding company." As such, contrary to our presentation, here, UCAN did not provide any information regarding SCE's ability to operate as a stand-alone utility without the services provided by EIX Executives, the fact that as the primary affiliate much of the EIX-officer efforts are directed toward SCE, or any allocations from EIX Executives between EIX and SCE.

comments on draft Resolution E-4963. These additional facts indicate the Commission should direct utilities to allocate such costs for SB 901-based exclusion and will be addressed in greater detail below.

SCE does not include the SCE-allocated share of Shared Officers and EIX Executives from its proposed SB 901-related forecast reduction, even for those positions that are at least Senior Vice President. This exclusion fails to recognize that without the presence of the Shared Officers and EIX Executives, SCE would need to employ and pay officers solely under the SCE umbrella to execute the function of Shared Officers and EIX Executives that were executed in service to SCE – the fact that SCE is held by Edison International (EIX) is largely a distinction without a difference. Indeed, the company admits the reason that it shares officers is for efficiency[706] – therefore, SCE would require the auspices of Shared Officers and EIX Executives without the parent-affiliate structure. As for EIX Executives, specifically, they should be excluded from rate-recovery given their stated focus on SCE: "As SCE is the primary operating subsidiary of EIX, each of these EIX executive positions is largely focused on SCE's operations and service."[707]

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[706] Ex. TURN-04-Atch-1 (Jones) (TURN DR 11-8) and Ex. SCE-06V03P01, p. 53:23-25. In the referenced data response, SCE states, "SCE does not maintain its own positions, separate from those that may be required by EIX, to fulfill the roles described in testimony because having the referenced shared officers represents is a cost-effective way to run the Company. Our customers benefit through reduced costs, as the salaries and benefits for these positions are shared between the companies rather than charged 100 percent directly to our customers."

[707] Ex. SCE-06, V03, P01, p. 53:25-27. TURN notes that SCE interprets the references sentence differently that we do, stating, "The Commission implicitly confirmed this view by approving Resolution E-4963, which defines the executive officer compensation and benefits that cannot be recovered from ratepayers. Resolution E-4963 defines an officer, as stated in SB 901, to mean "those employees of the investor-owned utilities;"[citation removed] thereby indicating that appropriate holding company executive officers' compensation can be recovered in rates." It is unclear to TURN how highlighting the cost-reducing impact of shared and EIX executives and

The Commission has recognized the recovery of expenses of the holding company from ratepayers, stating, in D.04-05-055, "…it is appropriate for the utility to pay for those services provided by the Holding Company that are both needed, and that are provided efficiently, without duplication of effort."[708] As TURN argues in its testimony, just as it is reasonable for the affiliate's ratepayers to compensate the holding company for costs that it incurs on behalf of the affiliate, it is reasonable to exclude those costs from rate recovery given that they would otherwise be excluded by PUC 706, but for the artificial construct of the holding company.[709] The majority of the Shared Officers' compensation, and the majority of some of EIX's officers' compensation, is charged to SCE at rates as high as 99%, as these officers are largely focused on SCE's operations and service.[710]

TURN also notes in its testimony that it is instructive to recognize that EIX and SCE hold their respective annual shareholder meetings, not as separate meetings, but as a single meeting that is hosted by both companies.[711] This is one illustration of the degree to which the two companies are intertwined, and further supports the exclusion of SCE-allocated Shared Officer and EIX Executive compensation from recovery in the GRC as a result of SB 901. SCE side-

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the large focus of EIX executives serves to support the view that the Commission held in Resolution E-4963 regarding excluding EIX-executive compensation as a result of SB 901.

[708] Ex. SCE-06, V03, P01, p. 53: FN 77.

[709] Ex. TURN-04 (Jones), p. 38: 8-12.

[710] Ex. TURN-04 (Jones), p. 39: Figure 4. Some EIX Executives and Shared Officers are allocated to SCE at 99%, while others are allocated to SCE at rates between 30% and 99%. Of the 13 EIX Executives and Shared Officers listed, 8 are allocated to SCE at an average rate of 99%.

[711] Ex. TURN-04 (Jones), p. 39: 7-8, referencing the press release regarding the annual shareholder meetings from 2019 (*Edison International and Southern California Edison to Hold Virtual Annual Meeting of Shareholders*).

steps the question of whether the SCE-allocated compensation of EIX and Shared officers should be included in the SB 901-related revenue reduction, by simply stating that SB 901 applies only to "an officer of an electric corporation."[712] While it is true this is what the statute states, this does not address the deeper question of whether SCE-allocated work of Shared and EIX officers should be considered as work for the electric utility and not the holding company, regardless of whether EIX nominally employs the executive.

28.4.4 Executive Incentive Compensation Program: The Commission Should Deny Ratepayer Funding for This Program, or at a Minimum Adopt a Reduction of $1.133 Million.

SCE separates its short-term Executive Incentive Compensation ("EIC") program, which covers compensation for executives, from its STIP program (covered below in Section 28.6), which covers non-officer executives. Executives include both officers of SCE and a portion of the cost of officers for Edison International.

As discussed above, TURN's primary recommendation for SCE's executive compensation is that the Commission not authorize any ratepayer funding for executive compensation. This primary recommendation also applies to the EIC program. Should the Commission decide that other treatment of this program would be more appropriate, TURN provides the following alternate recommendation.

Both EIC and STIP share the same goals and weights. TURN's expanded analysis and discussion of the STIP program and its goals is in Section 28.6 below. While TURN does not take issue with the EIC as a percentage of income, TURN has similar concerns with the EIC

[712] Ex. SCE-17, V3, p. 49: 4-10.

goals primarily benefiting shareholders, as they do in STIP. Hence, TURN recommends a reduction of $1.133 million for financial and lobbying related goals in the EIC.

28.5 Long-Term Incentives

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,[713] which are intended to reward SCE employees for promoting shareholder interests. The Commission has consistently denied SCE's request for rate recovery of costs associated with LTIP since at least the 2009 GRC.[714]

In its most recent rejection of SCE's request, noting SCE's standard defense that its overall compensation is at market, the Commission stated,

> The positions of both sides of this issue are essentially unchanged since SCE's 2015 GRC. In our decision in that proceeding, we concluded that LTI does not align executives' interests with ratepayer interests, and continued "our consistent practice" and denied SCE recovery for its LTI program. Our review of the record in the instant proceeding leads us to conclude that our approach should remain unchanged, and we again deny SCE recovery of its Test Year 2018 forecast LTI program expenses.[715]

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.[716] SCE does attempt to make one new argument to support the inclusion of its LTIP request in rates, citing AB 1054, which was enacted in 2019.[717]

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[713] Ex. SCE-17, V3, p. 53: 12-13.

[714] 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.

[715] D.19-05-020, p. 188.

[716] Ex. TURN-04 (Jones), pp. 41-43 & 45-46.

[717] Ex. SCE-06, V3, P1, p. 36

SCE is correct that, "AB 1054 amends the Public Utilities Code to limit the amount of guaranteed cash compensation, and instead move to a structure with incentives based on certain performance metrics."[718] However, as discussed in Exhibit TURN-04, there is nothing directly related to 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.[719] In fact, TURN presented evidence that stock incentives do not necessarily reflect safety performance,

> …A companies' stock value is not directly linked to its safety performance. While major catastrophes, like a large wildfire, are likely to impact stock value, these events do not always have a long-term impact on stock price. Further, a utilities' compliance with risk mitigation work often has little or no impact on the stock price, sometimes for many years. For example, PG&E's stock rose in value from around $30 a share just after its first bankruptcy to $47 in 2010 after San Bruno, then to around $70 in June 2017. While the share price rose tremendously, and an LTI program based on stock value would have rewarded executives greatly, in reality, the utility was mismanaging its system and neglecting management, as evidenced by numerous recent findings by the Commission. Good financial performance, even with a long-term view, does not mean the utility has ensured or prioritized public safety. In fact, rewarding financial performance could potentially cause executives to prioritize profits over public safety. PG&E's President recently acknowledged that its executives could at times be in a position where trade-offs have to be made between safety and earnings.[720]

Accordingly, stock price is not a clear indicator of safety performance. SCE did not respond to this argument directly in its Rebuttal Testimony, nor did it present a more compelling justification for rate recovery of LTIP costs. There is nothing directly related to AB 1054, or SCE's proposed approach to responding to its requirements, that warrants a change to the

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[718] Ex. SCE-17, V3, p. 55: 15-16.

[719] Ex. TURN-04 (Jones), pp. 43-44.

[720] Ex. TURN-04 (Jones), p. 44, FN 112, referencing Letter from TURN to the Director of Wildfire Safety Division re: Executive Compensation as it relates to the requirements of AB 1054 (dated February 5, 2020), pp. 11 (Para. 2) -12.

Commission's long-established policy of disallowing utilities' LTIP. Accordingly, the Commission should deny SCE's $11.602 million LTIP forecast.

28.6 Short-Term Incentive Program

SCE's annual Short-Term Incentive Program ("STIP) for employees provides incentive payments for non-represented employees, management employees, and non-officer executive employees, based on achievement of program goals.

TURN believes strongly that increases in STIP incentive levels should not exceed increases in SCE's labor costs. Incentive compensation should be used for employee incentives, not as a mechanism for increasing pay outside of "labor costs." Furthermore, SCE's increases are focused on highly paid managers and executives, without providing any evidence that the compensation increases are necessary or benefit ratepayers.

TURN is also concerned that SCE's STIP includes incentive goals that primarily benefit shareholders. Employee base pay is linked to activities, authorized by the Commission, to benefit utility customers. Incentive compensation, also funded by ratepayers, should motivate employees to "stretch" themselves to go above and beyond when performing these duties to provide safe and reliable service at just and reasonable rates. In this rate case, SCE proposes to drastically increase incentive payments by 70% (when compared to labor cost). This increase is unsupported and unwarranted. TURN recommends that the Commission disallow the requested increase.

Furthermore, SCE includes a number of measures in the STIP that primarily serve shareholder interests. These include a financial goal and incentives for successfully influencing the Commission and state policies in a number of areas. These latter goals are for lobbying, which are not appropriate to be funded by ratepayers. TURN recommends disallowing the cost of these goals at target, as discussed further below.

28.6.1 The Drastic STIP Increase Proposed by SCE Is Unwarranted and Unsupported, as Well as Contrary to Recent Commission Decisions

The Commission has repeatedly reduced SCE's past requests for increased STIP funding. In the 2012 GRC, DRA (name of Cal Advocates at that time) concluded that SCE's STIP request was well above (about 36%) the amount authorized for the 2009 test year. The Commission expressed concern about the rapid growth in discretionary short-term incentive costs and that the bonus targets were heavily weighted toward managers and executives over rank and file employees who then constituted 90% of the workforce.[721] In the 2015 GRC, SCE proposed a 46% increase in STIP spending over the Commission's adopted ratio of STIP at 10.94 percent of labor cost. The Commission authorized SCE STIP spending at 12.11% of its total labor forecast, citing the results of the Total Compensation Study showing SCE's compensation at below market.[722] In the 2018 GRC, SCE proposed STIP funding at 15.97% of labor expense. The Commission readopted a ratio of 12.11% of labor for short-term incentive funding.[723]

In this GRC, SCE's requested funding for STIP would total 21.2% of labor, *70% above* the 12.11% adopted in the previous two GRC decisions.[724] The impacts of the STIP increases would be uneven among employee groups and would be mainly attributed to higher salary levels.[725] SCE provides no evidence that such increases would be necessary to compete in the

[721] D.12-11-051, pp. 455-458.

[722] D.15-11-021, pp. 263-265.

[723] D.19-05-020, p. 186.

[724] Ex. SCE-06 V03 P1 WP Bka, p. 207.

[725] Ex. TURN-05, p. 9, citing TURN DR 34-05bi, Att. 1, TURN DR 40-03b, Att. 1.

labor market. In addition, SCE's Total Compensation Study results show that the company's compensation is already at market, which further shows that an increase is unnecessary.[726]

TURN maintains that incentive payments funded by ratepayers, at target, should remain a steady percentage of employees' base pay, allowing incentive payments to increase with the cost of labor. SCE justifies neither the STIP incentive increases in the Compensation Design Project, nor the cost increases resulting from KCIP payments, as necessary to retain valuable employees, or to serve the needs of ratepayers.

TURN's first adjustment to SCE's STIP request is to reduce proposed target program funding to 12.11% of labor, the Commission's established ratio of short-term incentive payment to labor in SCE's previous two GRC decisions.

SCE and TURN STIP Forecasts as Percent of Labor

2018 $000s			
	Edison	TURN	Difference
Edison STIP Proposal: 21.16%	$180,907		
Maintaining 12.11% of Labor		$103,519	($77,388)

In its rebuttal, SCE argues that the ratio of STIP to labor should be updated because SCE has been paying out a greater ratio from 2014 to 2019.[727] Since SCE paid out a greater ratio than what was authorized by the Commission, SCE argues that shareholders cannot be expected to make up the deficit because doing so would create "a Hobson's choice for SCE – either not spending authorized revenues in other areas or not paying investors their expected return."[728] Yet, from beginning of 2012 to end of 2019, SCE's stock increased by 75% and was up 100% at

[726] Ex. SCE-06 V3 P1, p. 44.

[727] Ex. SCE-17 V03, pp. 30-32.

[728] Ex. SCE-17 V03, p. 36.

one point.[729] Hence, there is no evidence to suggest that SCE was not able to pay investors their expected return as SCE claims.

Thus, SCE has not provided evidence to warrant a 70% increase from the Commission's approved STIP to labor ratio of 12.11% to 21.2%. The Commission should reject SCE's proposed drastic increase in STIP funding and attempt to give itself a large pay raise in the middle of a pandemic.

28.6.1 SCE's Proposed Metrics, Including Its Safety Metrics, Insulate STIP Recipients from Poor Safety Performance That Results in Fatalities

SCE states that variable "at risk" pay helps employees align their motivations and job performance with important Company goals that benefit customers.[730] SCE further agrees that in order for employees to align their motivation and job performance with goals that benefit customers, it is important for the metrics selected to reflect outcomes that benefit customers.[731] Being provided safe electric service is one of the most important outcomes that would benefit SCE's customers, and the risk of wildfire is one of the greatest safety risks to SCE's customers.

Yet, SCE concedes that none of the metrics on which SCE has chosen to base the STIP award would be affected by a catastrophic wildfire that results in fatalities to the public. More specifically, if SCE's equipment were to cause a catastrophic wildfire that resulted in numerous fatalities to the public, all of the STIP metrics chosen by SCE would not be impacted, including wildfire resiliency metrics, operational and service excellence metrics, policy, growth and

[729] https://finance.yahoo.com/quote/EIX?p=EIX&.tsrc=fin-srch

[730] Ex SCE-17 V03, p. 11.

[731] 08 RT 895:22-896:5 (Bennett/SCE).

innovation metrics, and diversity, people, and culture metrics.[732] In other words, the bonuses for SCE's employees and executives would not be affected *at all* if SCE's equipment causes a wildfire and kills numerous members of the public. In fact, the only way that SCE's STIP payout could be affected by a catastrophic wildfire with fatalities *caused by SCE* is if its Board of Directors, at its discretion, decides to reduce the bonus payout. Furthermore, regardless of how many fatalities results from a wildfire caused by SCE's equipment (whether one or one hundred), SCE's Board has complete discretion regarding how much, if any, of the STIP payout should be reduced.

It is outrageous for SCE to suggest that ratepayers should fund $181 million of bonus per year for SCE employees and executives when the targets and metrics insulate STIP recipients from poor safety performance that results in fatalities to the public, which could include customers that are paying a part of these bonuses. The metrics that SCE has chosen to reward itself clearly do not represent safety performance, and ratepayers should not be expected to provide full funding for metrics that are not aligned with the customers' best interests, such as safety.

28.6.2 Ratepayers Should Not Fund STIP Goals and Objectives that Primarily Benefit Shareholders

While most of the goals in SCE's STIP have the potential to benefit ratepayers in addition to shareholders, the Financial Performance Goal of "Achieve Core Earnings" primarily benefits shareholders, not ratepayers. Similarly, goals to shape legislation and regulatory policy primarily benefit shareholders. This includes goals within the Policy, Growth and Innovation

[732] 08 RT 901:10-904:8 (Bennett/SCE).

Goal Category, and policy goals within the Wildfire Resiliency Goal Category.[733] Shareholders should be responsible for these incentive costs.

The Commission supports this view, as it reaffirmed in SCE's 2015 and 2018 GRC decisions regarding STIP:

> In our decision on the STIP in SCE's 2015 GRC application, we noted that in recent GRCs for all utilities we adopted reductions to short term incentives to account for payouts that are driven by shareholder benefits rather than ratepayer benefits. We found that "significant portions of the payout criteria are directly related to shareholder benefits," including achieving decisions in Commission proceedings (GRC, cost of capital) with outcomes or adopted policies that may or may not provide secondary benefits to ratepayers.[734]

In SCE's most recent GRC decision, the Commission first reduced STIP funding to 12.11% of labor expense and then also removed the incentives related to the financial goal, noting its lack of benefit for ratepayers.[735] TURN takes a similar approach here.

<u>The Financial Performance Goal "Maintain Core Earnings" Primarily Benefits Shareholders</u>

Thirty percent of the STIP goals for SCE employees, at target, are based on achieving a level of Core Earnings. Core Earnings are not financial results that adhere to Generally Accepted Accounting Principles ("GAAP"). SCE's Core Earnings are "the after-tax earnings from SCE's principal business, and exclude non-core income and losses not considered representative of the Company's ongoing earnings."[736] Since SCE's "Core Earnings" are self-

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[733] Ex. TURN-05, citing TURN DR 10-05b, Att 1.

[734] D.19-05-020, p. 185.

[735] D.19-05-020, pp. 185-186.

[736] Ex. SCE-06 V3 P1, p. 48.

defined and non-GAAP, they cannot be reliably compared to earnings for other corporations, nor can they be reliably used for financing purposes.[737]

SCE argues that ratepayers benefit from the "Core Earnings" Financial Performance goal in STIP, stating that "Core earnings are essential to maintain SCE's financial health and to provide lower cost of capital to finance the capital projects and other essential programs that benefit its customers and support delivery of safe and reliable service."[738] SCE further notes in its 2019 Proxy Statement that "Core earnings (losses) are also used when communicating with investors and analysts regarding Edison International's earnings results to facilitate comparisons of the company's performance from period to period."[739] The logic of SCE's two statements suggests that investors follow and use "Core Earnings" as the basis of investment decisions and reflect Edison's financial health. However, as shown below, this is contrary to undisputed evidence.

The graph below demonstrates Edison International's annual Core Earnings results in comparison with annual GAAP Net Income results for SCE.[740]

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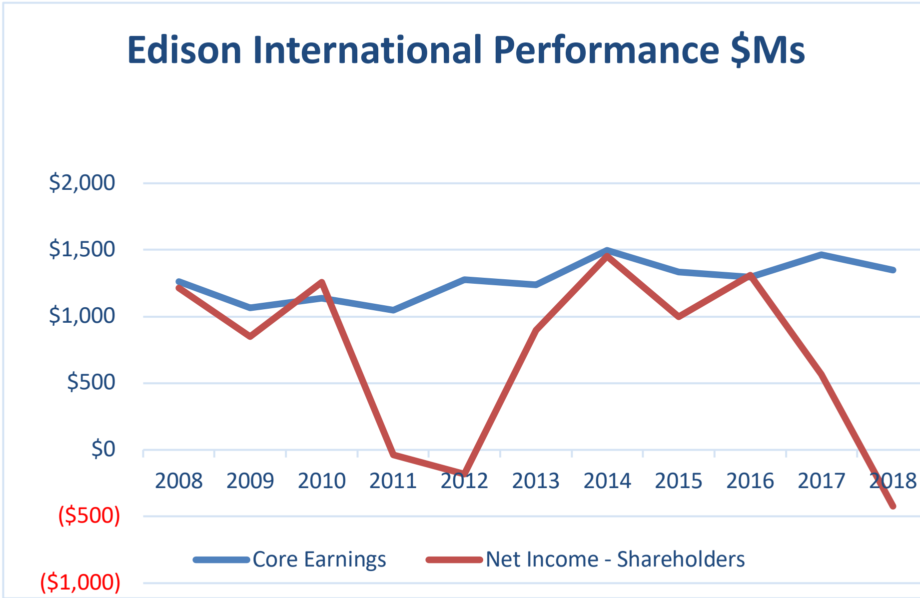
[737] Ex. TURN-05, p. 13, citing TURN DR 26-1.a-b, Appendix A.

[738] Ex. SCE-06 V03 P1 BkA, p. 48.

[739] Ex. TURN-05, p. 14, citing TURN DR 26-01, Appendix C.

[740] Ex. TURN-05, p.14, citing EIX Annual Reports: 2009, p.i; 2010, p. i, 2011, p. i, 2012, p. i, 2015, p. 47, 2016, p. 47, 2017, p. 44, 2018, p. i.

Table 1: Core Earnings vs. Net Income



While "Core Earnings" may look relatively stable, they do not reflect the results that shareholders experience. For example, in 2018, SCE omitted most of the cost of "Wildfire-related claims, net of recoveries" from its calculation of core earnings. These wildfire-related costs were largely responsible for SCE's negative basic earnings that year,[741] and these costs reduce the earnings available to shareholders or service debt. Hence, Core Earnings bears little resemblance to the true financial health of a company, and awarding STIP based on Core Earnings would not be equivalent to motivating or rewarding results that increases financial health and therefore lower the cost of capital, as SCE claims. Furthermore, SCE provides *no evidence* that good Core Earnings would allow SCE to raise capital at lower cost than poor Core Earnings performance.

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[741] *Id.*, p. i.

In its rebuttal, SCE argued that "Non-core items include income or loss from discontinued operations. These items also encompass income or loss from significant discrete items that management does not consider representative of ongoing earnings."[742] SCE goes on to state that "Core Earnings go both ways, so to speak," suggesting that it is reasonable for SCE to exclude costs from Core Earnings since it may also exclude income. Yet, during evidentiary hearings, SCE's witness admitted that he is not aware of any gain in the range of $2.4 billion to $4.7 billion dollars that has ever been excluded from Core Earnings, which is what SCE has removed for wildfire liability costs and wildfire insurance fund contributions.[743] Clearly, to suggest that SCE's exclusions from Core Earnings "go both ways" is recklessly inaccurate. The Core Earnings metric that SCE uses to award bonuses to its employees and executives bears no resemblance to the financial performance and financial health of the company since it has arbitrarily removed costs from the metric.

Thus, not only does the financial measure which SCE uses for its STIP primarily benefits shareholders, it also does not represent true financial health of the utility (and the associated savings to ratepayers as suggested by SCE). Consistent with recent SCE GRC decisions, ratepayers should not fund the incentives for this goal.

<u>SCE's Lobbying Activities or "Policy Shaping Activities" Primarily Benefit Shareholders</u>

SCE's 2019 STIP goals give 15% of program target weight to the Policy, Growth and Innovation Goal Category. Four of the seven goals within this category involve incentive

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[742] Ex. SCE-17 V03, p. 17.

[743] 08 RT 909:1-6 (Bennett/SCE).

payments for shaping legislative and regulatory policies.[744] SCE is focused on 1) the results of this GRC, 2) the Commission's Cost of Capital proceeding, 3) State transportation electrification policy and 4) Community Choice Aggregation and Distributed Generation policies.[745] In the Wildfire Resiliency Goal Category, SCE includes the goal of "Policy Reform, Wildfire." SCE describes this effort as "pursuing wildfire policy in regulatory, legislative, and legal forums which improve cost recovery certainty and reasonable allocation of liability."[746]

In SCE's 2015 GRC, the Commission found that SCE had *not* demonstrated that costs of incentives "directly related to shareholder benefits such as achieving decisions in CPUC proceedings (GRC, Cost of capital) with certain outcomes and achieving public policy objectives that may or may not provide secondary benefits to ratepayers" are reasonable.[747] In SCE's 2018 GRC, the Commission restated the same position "that 'significant portions of the payout criteria are directly related to shareholder benefits,' including achieving decisions in Commission proceedings (GRC, cost of capital) with outcomes or adopted policies that may or may not provide secondary benefits to ratepayers."[748] The fact that these activities may or may not provide benefits to ratepayers has not changed.

In its rebuttal, SCE argues that its regulatory goals are based on advocating for its customers, not for its shareholders.[749] Yet, SCE's own proxy statement reveals that the

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[744] Ex. TURN-05, p. 16, citing TURN DR 10-05b Attch. 1.

[745] Ex. TURN-05, p.16, citing TURN DR 10-05b Attch. 1.

[746] Ex. TURN-05, p.16, citing TURN DR 10-05a.

[747] D. 15-11-021, pp. 264-5.

[748] D. 19-05-020, p. 185.

[749] Ex. SCE-17 V03, pp. 18-24.

"majority of executive compensation is at risk and *aligned with shareholder interest.*"[750] This clearly indicates that SCE executives' motivation and job performance are mostly aligned with shareholder interest, not ratepayer interest. If the executives' motivation and performance are mostly aligned with shareholder interest, it is also reasonable to expect that SCE's employees' motivation and performance, including when engaged in advocacy and lobbying, will be mostly aligned with shareholder interest.

Thus, consistent with previous GRC decisions, ratepayers should not be responsible for paying bonuses to SCE's employees for effective lobbying.

<u>An Estimated 20% in STIP Weighting Is Related to Lobbying Activities</u>

SCE is unable to estimate how much of the 15% weight for this goal category is represented by the lobbying goals.[751] TURN therefore looks at past performance in this goal category to determine the lobbying/advocacy goals' contribution.

In 2019, the goal of "California legislative and regulatory developments aligned with SCE's strategy" carried 10 points of the 16 points in this goal category. That is 63% of the category weight, or over 9% of the total STIP target.[752] In 2018, The Policy Growth and Innovation Goal Category had a STIP target weight of 25%. Achieving favorable outcomes in the 2018 GRC and other CPUC and legislative processes was responsible for 7 points out of the 19 points. This is 37% of the Goal Category weight, or also 9% of the total STIP target.[753]

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[750] Ex. TURN-62, 2019 Joint Proxy Statement, p. 3. (Emphasis Added)

[751] Ex. TURN-05, p.17, citing TURN DR 10-05 a-l, p.3.

[752] Ex. TURN-05, p.17, citing EIX-SCE 2020 Proxy Statement, p. 44.

[753] Ex. TURN-05, p.17, citing EIX-SCE 2019 Proxy Statement, p. 38.

Thus, TURN uses a weight of 9% of STIP target for lobbying in the Policy Growth and Innovation Goal as the basis of our recommended disallowance.

The Wildfire Resiliency goal category for STIP is new in 2019. SCE has valued it at 20% of the STIP target score. This goal category includes 8 operational goals to reduce wildfire risk. This goal category also includes one goal for "Policy Reform, Wildfire."[754] In 2019, SCE exceeded its target in Wildfire Resiliency on both the operational goals and the Policy Reform goal. The Policy Reform goal results, for activities related to lobbying or "advocating," equaled slightly more than half, 53%, of the Wildfire Resiliency score.[755] This equals 11% of the STIP result. Thus, TURN uses a weight of 11% of the STIP target for lobbying in the Wildfire Resiliency goal, half of the goal category weight.

TURN combines the 9% STIP weight for lobbying in "Policy, Growth and Innovation" and the 11% STIP weight of lobbying in "Wildfire Resilience" and recommends a 20% disallowance from the STIP forecast for lobbying related activities.

28.6.3 Ratepayers Should Not Fund Bonus Programs that Even SCE Agrees Are Arbitrary and May Not Benefit Ratepayers

SCE proposes to add its Known Contributor Incentive Program ("KCIP") payouts to the cost of its STIP incentives, which is additional incentive compensation provided to some employees. All of the KCIP-eligible employees are in pay grades 17 and 18,[756] including

[754] Ex. TURN-05, p.17, citing TURN DR10-05b, Att. 1.

[755] Ex. TURN-05, p.17, citing op cit. 2020 Proxy Statement, p. 44.

[756] Ex. TURN-05, p. 11, citing TURN DR 40-03 a-d.

Principal Managers, Attorneys, Senior Attorneys, Expert Level Jobs and the CEO's Senior Advisor.[757]

The KCIP incentives are unrelated to the goals of STIP. SCE notes that "an employee receives a KCIP award which recognizes his or her achievements in the prior year as well as expected future contributions," which "serves as a valuable recognition and retentive tool."[758] SCE further notes that KCIP payouts are based on manager discretion, and that no specific metrics have been identified.[759] In fact, SCE does not dispute the fact that since the KCIP metrics are based on manager discretion, the targets adopted by the managers may not benefit ratepayers.[760] In other words, if SCE's proposal is adopted, SCE's customers may be paying for bonus payouts that do not benefit ratepayers.

Thus, since SCE provides no evidence that KCIP spending is necessary for employee retention, nor evidence that the program encourages behavior that benefits ratepayers, the Commission should deny ratepayer funding for the STIP costs related to this program.

28.6.4 TURN's Recommendation: The Commission Should Adopt a Reduction of $129.1 Million to Account for Unwarranted Increase and Goals that Primarily Benefit Shareholders

In sum, TURN recommends that the Commission reject SCE's proposal to increase its STIP to labor cost ratio by 70%. Instead, the Commission should adopt the same ratio of 12.11%, which results in a reduction of $77.4 million. In addition, ratepayers should not pay for metrics and goals that primarily benefit shareholders, and the Commission should adopt a

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[757] Ex. TURN-05, p. 11, citing TURN DR 47-01 a-b.

[758] Ex. SCE-06 V03 P1, p. 42.

[759] 08 RT 916:6-19 (Bennett/SCE).

[760] 08 RT 916:20-917:1 (Bennett/SCE).

reduction for these metrics, including the financial measure metrics and the lobbying related metrics, which total $51.8 million. TURN's recommendation is summarized in the table below:

Table 28-2: TURN 2021 STIP Recommendation

	2018 $ 000s		
	Edison Forecast	TURN Recommendation	Difference
Edison STIP at 20.9% of Labor	$180,907		
Maintain STIP at 12.11% of Labor		$103,519	($77,388)
---Measure Reductions---			
Financial Measure: 30%		($31,056)	($31,056)
Lobbying/influence: 20%		($20,704)	($20,704)
TURN Recommendation		$51,759	($129,148)

28.6.5 The Commission Should Also Pursue a Policy of Sharing STIP Costs Between Shareholders and Ratepayers for Metrics that Benefit Both

The Commission has repeatedly noted that benefits from incentive compensation accrue to both shareholders and ratepayers. As it noted in PG&E's 2014 GRC Decision, this discussion has gone on for the last 20 years.

> "In D.00-02-046, we adopted a policy of allowing 50% recovery of targeted employee incentive program costs from ratepayers, stating: '[S]hareholders and ratepayers alike benefit from the good performance that incentive programs such as PIP seek to encourage. We continue to believe that equal sharing of cost is fair, and that it provides appropriate incentives to the utility to perform in ways that benefit ratepayers and shareholders alike.'"[761]

In PG&E's 2017 GRC Decision, the Commission commented, "ratepayers derive benefits from various elements of the STIP and should bear a reasonable level of costs commensurate with benefits, although PG&E shareholders benefit from STIP as much as or more than do

[761] D.14-08-032, p. 523.

ratepayers."[762] This notion is also supported by PG&E's statements in its recent bankruptcy proceeding:

> "The 2019 STIP, like prior STIPs and similar incentive plans of the Debtors' peer companies, is essential to stabilize and motivate the employee base and to align the participants' performance with objectives of the Company; namely, to provide safe and reliable service to the Debtors' customers and maximize enterprise value for the benefit of the Debtors' economic stakeholders, including the Objectors"[763]

TURN agrees with the Commission that shareholders benefit from short-term incentives that also benefit ratepayers. SCE has a history of attempts to increase authorized STIP spending as a percentage of labor costs. The beneficiaries of these proposed increases are the more highly paid recipients of STIP incentives. In past years, SCE has decided to fund these STIP increases with shareholder funds. TURN believes that this is evidence that SCE and its shareholders are aware of the benefits they accrue as a result of good STIP performance. Furthermore, as a general rule, it is not good public policy to include 100% of incentive payments in rates. If employees earn their bonuses, shareholders are doing well and can afford to pay them. If they do not earn their bonuses, but 100% of the target level bonuses are included in rates, the shareholders receive a windfall because the money to pay the then non-existent bonuses results in earnings.

Thus, TURN recommends that the Commission consider a formal policy of sharing STIP costs between shareholders and ratepayers for measures that benefit them both. This would allow utilities to be aware that their shareholders would be expected to participate in incentive

[762] D.17-05-013, p. 103.

[763] Ex. TURN-05, p.19, citing United States Bankruptcy Court Northern District of California San Francisco Div., Bankruptcy Case no. 19-30088Reply Memorandum of Points and Authorities in Further Support of Corrected Motion of Debtors… April 9, 2019 p. 15.

costs when they design the programs to present in GRCs. In addition, as discussed above, TURN also believes that the Commission should continue to deny ratepayer funding for measures that primarily benefit shareholders.

28.7 401(k) Savings Plan

28.8 Dental Plans

28.9 Disability Management - Programs

28.10 Group Life Insurance

28.11 Medical Programs

28.12 Miscellaneous Benefit Programs

28.13 Recognition

28.14 Vision Service Plan

28.15 Other Issues

29. EMPLOYEE TRAINING & SUPPORT

29.1 OU Support Services

SCE forecasts $32.816 million in O&M expense (i.e., $22.880 million, labor; $9.936 million, non-labor) for OU Support Services. The Commission should instead adopt an O&M forecast of $29.323 million (i.e., $21.591 million, labor; $7.732 million, non-labor), as per the following table, which results in a total reduction for the activity of $3.493 million.

SCE and TURN forecasts for OU Support Services (1,000s of 2018$)[764]

[764] 2018 (recorded) and SCE's 2021 forecast: Ex. SCE-06, V3, P1, p. 10: Figure II-4.

Catetory	2018 Recorded	2021 Forecast		
		SCE	TURN	SCE > TURN
Labor	21,898	22,880	21,591	1,289
Non-Labor	7,732	9,936	7,732	2,204
Total	29,630	32,816	29,323	3,493

The Commission should reduce SCE's labor forecast because SCE chooses a "last recorded year" method for this forecast but then applies a labor escalation, effectively double counting escalation.[765] As TURN noted in Testimony, SCE inappropriately applied a 2.9 percent labor escalation rate to its 2018 base year forecast which was already in constant dollars.[766]

Regarding SCE's non-labor forecast, the Commission should reject SCE requested increase to Base Year costs of $7.732 million by $2.204 million in order to account for "special accounting fees and vendor costs to incorporate changes to the benefit programs and participant web sites caused by union negotiations for 2019 through 2021," resulting in a Test Year forecast of $9.936 million.[767] As TURN demonstrated in Testimony, SCE's proposed increase was based on a vague and speculative claim that it will see costs for this category increase due to additional groups at SCE who are attempting to organize.[768] However, SCE admitted in its rebuttal testimony that the group of employees attempting to organize remain non-represented after a recent vote.[769]

[765] Ex. SCE-06, V3, P1, p. 15: 17-18.

[766] Ex. TURN-04 (Jones), p. 26: 5-9.

[767] Ex. SCE-06, V3, P1, p. 16: 3-6.

[768] Ex. TURN-04 (Jones), p. 26: 20-25.

[769] Ex. SCE-17, V3, p. 8: 10-11.

In Rebuttal, SCE indicated that it does not contest TURN's recommendation to reduce the Test Year forecast for OU Support Services by $1.289 million for labor and $2.204 million for non-labor, for a total reduction of $3.493 million.[770] Accordingly, the Commission should adopt TURN's recommended reductions to SCE's original OU Support Services forecasts.

30. TOTAL COMPENSATION STUDY

31. ENVIRONMENTAL SERVICES, AUDITS, ETHICS & COMPLIANCE, AND SAFETY PROGRAMS

32. ENTERPRISE OPERATIONS

32.1 Facility & Land Operations

TURN recommends reductions to, and disallowances of certain projects, encompassed by two of SCE's five Facility and Land Operation capital programs, infrastructure updates and substation reliability upgrades.

32.1.1 Capital Expenditures for Infrastructure Upgrades: Overview

SCE forecasts total expenditures for Infrastructure Upgrades of $201.944 million from 2019 through 2023.[771] The Commission should adopt TURN's recommendation to reduce SCE's forecast by $82.874 million by reducing SCE's forecast for the Blythe Service Center, and disallowing SCE's request for the following three Infrastructure Upgrade projects: (1) Santa Barbara Service Center, (2) T&D Training Center, and (3) Vehicle Maintenance Facilities, as summarized in the Table below.

[770] Ex. SCE-17, V3, p. 8: 15-17.

[771] Ex. SCE-17, V5 (Neal), p. 4: 3-4.

TURN Recommendation for Capital Expenditures for Infrastructure Upgrades[772]

	Nominal $000s		
INFRASTRUCTURE UPGRADES	SCE	TURN	DIFFERENCE
Blythe Service Center	$ 13,213	$ 11,159	$ (2,054)
Santa Barbara Service Center	$ 15,123	$ -	$ (15,123)
T&D Training Center	$ 45,285	$ -	$ (45,285)
Vehicle Maintenance	$ 22,646	$ -	$ (22,646)
Total	$ 96,267	$ 11,159	$ (85,108)

32.1.1.1 The Commission should Limit SCE's Recovery for the Blythe Service Center to the Recorded Costs of the Project.

As shown in Exhibit SCE-17, Volume 5, the Blythe Service Center was fully in use and useful at the end of 2019 and SCE recorded $11.159 million in expenditures for the project in 2019.[773] However, SCE originally requested $13.213 million for the project to account for final invoices to be paid in 2020.[774] The Commission should authorize no more than what was actually spent for the project. SCE's witness Mr. Neal conceded to TURN's position during evidentiary hearings, stating, "we seek to recover $11.159 for expenses incurred in 2019 related to the Blythe Service Center and we reserve the right to recover additional funds in the next general rate case to true-up unpaid invoices that were incurred in 2019 and early 2020 …".[775] Accordingly, the Commission should adopt TURN's recommendation to reduce SCE's forecast for the Blythe Service by $2.054 million.

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772 This Table compares TURN's recommendations with SCE's request in its direct testimony. SCE appears to have modestly modified its request for the Blythe Service Center and T&D Training Center projects in its rebuttal testimony, Ex. SCE-17, V5 (Neal), p. 5, Table I-5.

773 Ex. SCE-17, V5 (Neal), p. 6: 12-18.

774 *Id.* at pp. 6-7: 18-19 & 1.

775 5 RT 688-689, 27-28 & 1-5 (SCE/Neal).

32.1.1.2 The Commission should Deny Recovery of SCE's Request for the Santa Barbara Service Center.

SCE requests $15.123 million to locate, plan, and purchase a parcel for the Santa Barbara Service Center to be spent after the test year, in 2022-2023. The forecast includes $1.068 million for planning and programming in 2022 and $14.055 million for land purchase and environmental studies.[776] SCE's request should be rejected for two reasons, each of which are an independently sufficient basis to deny the request. First, SCE's request is improper as the project will not be completed during this GRC cycle. Second, as will be addressed in greater detail below, the Commission should deny SCE's request as the Company already received $48.6 million for this project in the 2018 GRC and the company re-prioritized the funds for other projects.

[776] Ex. SCE-06, V5 (Neal), pp. 37-38.

32.1.1.2.1 The Land Acquisition Costs for the Santa Barbara Service Center Should Not be Included in this GRC because the Funds Will Not be Spent by the End of the Test Year.

Regarding TURN's first justification for denying SCE's request, SCE has made it clear that it does not anticipate incurring any costs for this project in the test year. In response to a data request regarding the Santa Barbara Service Center, SCE states, "SCE forecasts $15.123 million for the acquisition of land and related costs during 2022-2023".[777] Accordingly, review of these costs in the present GRC is inappropriate.[778]

SCE's response to this argument presented by TURN in testimony fails to address the crux of the issues. SCE references the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, stating that under Plant Held for Future Use (PHFFU), "provides that land purchased in anticipation of future requirements be included in rates".[779] This argument misses the point, TURN is not challenging SCE's ability to generally recover land purchase costs, TURN is challenging recovery because SCE has not yet purchased the land or demonstrated it is likely it will purchase the land, instead SCE is requesting funding for hypothetical land acquisition costs related to the purchase of a parcel that may not happen. Both the "FERC and CPUC guidance" SCE refers to in its attempt to justify recovery of these costs, clearly apply to land acquisition costs that have already been incurred.[780] SCE's witness agreed with this interpretation during evidentiary hearings,

> Q. So according to the sentence you just read, plants held for future use is land and plant-related items that have already been acquired, and have not been put into use. Is that correct?

[777] Ex. TURN-49, p. 3, SCE Response to DR TURN-SCE-080, Q.3c.

[778] The Scope of Review of an IOU's capital forecast is generally limited to the test year and the two years preceding the test year. See D.12-11-051, (SCE 2012 GRC), pp. 24-25, "A major difference between SCE's capital forecasts and the forecasts of other parties is that for most

A. That's the way I would interpret it, yes.[781]

Accordingly, the CPUC and FERC guidance SCE attempts to rely on, does not address the realities of the present situation in which SCE has not yet acquired a parcel for the project, and does not currently anticipate doing so, by the end of the test year. The Commission should reject these speculative and uncertain future costs that SCE has failed to demonstrate will materialize. If the utility is convinced of the need for this relocation, it can choose to go forward with the project and present a more compelling analysis in support of its funding request in the next GRC.

32.1.1.2.2 SCE has Failed to Establish the Reasonableness of the Project Costs in Light of its History of "Re-Prioritizing" Funds Authorized for this Project in the Last GRC.

In the 2018 GRC, the Company requested $48.6 million to relocate the Santa Barbara Service Center. The Commission authorized the full amount despite TURN's objections.[782] However, the Commission warned against diversion of the funds authorized for the project. The Decision stated,

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categories, the parties did not examine 2013-2014 capital expenditures. In this decision, we examine SCE's forecast 2010-2012 capital expenditures, even if a project includes proposed spending in subsequent years. This is consistent with prior GRCs, due to both the limited resources of the parties, but also to the greater degree of speculation present the farther the estimated costs are projected from 2009 (when developed by SCE)."

[779] Ex. SCE-17, V5 (Neal), p. 9: 4-7.

[780] Ex. TURN-49, p. 4 & 8, SCE Response to DR TURN-SCE-080, Q.3a Attachment. The FERC guidance states, "7. Land and Land Rights. A. The accounts for land and land rights shall include the cost of land owned in fee by the utility and rights." The CPUC guiandance states, "J. Plant Held for Future Use (PHFU): PHFU includes land and plant related items that have been acquired by Edison for use in the future.

[781] 5 RT 680-681, 26-28 & 1-4 (SCE/Neal).

[782] D.19-05-020, p. 222.

> That said, we emphasize that we expect this project to go forward as planned, without the diversion of funds that TURN documented in its testimony for other projects. In the event that SCE does divert these funds, we will consider whether the financial responsibility for this project should be placed on SCE's shareholders. [783]

The exact situation the Commission warned SCE about in the last GRC has occurred, SCE did not spend any of the authorized $48.6 million on the Santa Barbara Service Center project.[784]

Based on SCE's history of not spending authorized amounts for this project and the many challenges SCE has faced in locating a suitable parcel,[785] there is not sufficient certainty that the Company will even complete the purchase of land and environmental studies as scheduled. Additionally, SCE did not conduct a cost-benefit analysis for the project in this GRC[786] which would have been useful to inform the reasonableness of this project given the difficulties SCE has had locating a parcel. Accordingly, it is unjust and unreasonable to continue authorizing tens of millions of dollars of ratepayer funds for this project and the Commission should follow through on enforcing its warning from the 2018 GRC (that SCE has continued to ignore) and reject SCE's forecast for land acquisition costs for the Santa Barbara Service Center.

32.1.1.3 T&D Training Center

In the 2018 GRC Decision, the Commission authorized $92.037 million for the T&D Training Center.[787] From 2017 to 2018, Edison unsuccessfully attempted to purchase land for

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[783] *Id.*

[784] 5 RT 672, 6-9 (SCE/Neal).

[785] Ex. SCE-06, V5 (Neal), pp. 36-37; See also, Ex. TURN-10-Atch-1, p. 4, SCE Response to DR TURN-SCE-031, Q11a-b; See also, 5 RT 676-677, 27-28 & 1 (SCE/Neal): Q. Okay. And SCE has not been able to purchase a parcel, to date. Is that correct? A. Unfortunately, no.

[786] 5 RT 675, 26-28 (SCE/Neal).

[787] Ex. TURN-10-Atch-1, p. 5, SCE Response to DR TURN-SCE-030 Q13a.

the project.[788] Through 2019, only $2.132 million had been spent on the Center.[789] In the present GRC, SCE is requesting $45.285 million to complete the project and has decided to consolidate the existing T&D training facilities at Chino, Westminster, and Alhambra to available space at the Rancho Vista site.[790] The Commission should deny SCE's request as the Company already received $92.037 million for this project in the 2018 GRC and the company re-prioritized the funds for other projects.[791]

SCE also fails to provide sufficient justification for the project. TURN requested support for the requested T&D Training Center costs and the Company provided a single page cost summary from CCMI.[792] The sheet lists estimated costs in the categories of construction cost, Furniture, Fixtures, and Equipment, pre-construction costs, and management costs, but does not provide any supporting documents. This is not sufficient support. The discovery request asked for support and included examples such as bids, contracts, and invoices, but none of these were provided. It is the burden of SCE to support its requests and SCE is not entitled to a "presumption of prudence,"[793] and a single page listing of estimated costs is insufficient. The

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[788]Ex. SCE-06, V5 (Neal), p. 38.

[789] Ex. TURN-10, p. 13, "Actual Capital Expenditures for T&D Training Center" Table. SCE spent $1,276,000 2015-2018 and $856 in 2019. See Ex. TURN-10-Atch-1, p. 5 & 22, TURN-SCE-030 Q13a-b, TURN-SCE-057 Q14.

[790] Ex. SCE-06, V5 (Neal), pp. 38-39.

[791] Ex. SCE-17, V5 (Neal), p. 13: 14-17.

[792] Ex. TURN-10-Atch-1, p. 6, SCE Response to DR TURN-SCE-030 Q14.

[793] D.85-08-102 (Helms Pumped Storage Project), 18 CPUC 2d 700, 709-710; D.93-05-013, 49 CPUC 2d 218, 220.

utility must carry this burden affirmatively, and the Commission has found requests for rate increases that lack sufficient evidence of reasonableness are subject to dismissal.[794]

The lack of support provided for the project, coupled with the fact that over $92 million has already been collected from ratepayers for this project justifies a complete rejection of the SCE's forecast for this project. It is unjust and unreasonable to continue authorizing tens of millions of dollars of ratepayer funds for this project.

32.1.1.4 Vehicle Maintenance Facilites

The Commission should reject SCE's request for $22.646 million for a new vehicle maintenance facility because, as discussed above in Section 32.1.1.2, SCE was once again authorized funding for this project in the 2018 GRC but the project was delayed and SCE re-prioritized the funds for other projects.[795] SCE admits that it did not spend any of the previously authorized funding on the project as no expenditures were recorded for this project from 2016-2019.[796] The Commission should not re-authorize spending for this project yet again.

Similar to the T&D Training Center discussed above, SCE also fails to provide sufficient justification for this project. TURN requested support for SCE's Vehicle Maintenance Facilities costs and the Company only provided a cost summary from CCMI.[797] Once again SCE has not met its burden to support its request. The Commission should reject SCE's request as it has not

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794 D.86-10-069, 22 CPUC 2d 124, 150.

795 Ex. TURN-10, p. 14: 10-12; Ex. SCE-17, V5 (Neal), p. 16-17.

796 Ex. TURN-10-Atch-1, p. 8, SCE Response to DR TURN-SCE-030 Q16b.

797 Ex. TURN-10-Atch-1, pp. 9-10, SCE Response to DR TURN-SCE-030 Q18.

made a reasonable showing regarding the expected costs of the project, nor has it provided sufficient evidence that the project will go forward as planned.

Additionally, as addressed above in Section 32.1.1.2.1, review of these costs in the present GRC is inappropriate as the project is not scheduled to commence until 2022,[798] and SCE does not anticipate incurring any costs in the test year.[799]

32.1.2 The Commission Should Deny SCE's Request for Capital Expenditures for Two Substation Reliability Upgrade Projects it Received Funding For in the 2018 GRC.

Consistent with TURN's analysis and recommendations, the Commission should reject SCE's request for $15.005 million for the Devers and Rector Maintenance and Test Buildings. However, TURN notes that SCE appears to have decreased its original request for both of the substation reliability upgrade projects TURN objected to, reducing its request for the Devers Maintenance & Test Building from $4.643 million to $2.735 million, due to 2019 recorded costs being more than 50% less than forecast.[800] Additionally, SCE reduced its request for the Rector Maintenance and Test Building from $10.362 million to $8.046 million.[801] If the Commission declines to adopt TURN's recommendations to reject but of these projects, then it should at the

[798] The Scope of Review of an IOU's capital forecast is generally limited to the test year and the two years preceding the test year. See D.12-11-051, (SCE 2012 GRC), pp. 24-25, "A major difference between SCE's capital forecasts and the forecasts of other parties is that for most categories, the parties did not examine 2013-2014 capital expenditures. In this decision, we examine SCE's forecast 2010-2012 capital expenditures, even if a project includes proposed spending in subsequent years. This is consistent with prior GRCs, due to both the limited resources of the parties, but also to the greater degree of speculation present the farther the estimated costs are projected from 2009 (when developed by SCE)."

[799] Ex. SCE-17, V5 (Neal), p. 16, Table I-9.

[800] Ex. SCE-17, V5 (Neal), p. 20, Table I-11.

[801] *Id.* at p. 22, Table I-12.

very least only adopt SCE's apparent "rebuttal position" which utilizes the 2019 recorded costs which are lower than SCE's forecast.

32.1.2.1 Devers Maintenance and Test Building

The 2018 GRC Decision authorized $5.005 million for the Devers Maintenance and Test Building project, but SCE has only spent approximately 30% of the authorized funding on the project to date.[802] Once again, the Company is requesting money for a project they failed to complete in the past rate case cycle. The Commission should put a stop to this pattern now, SCE should be held accountable for completing its proposed projects with the initial funding that was authorized.

SCE also fails to appropriately justify its forecast for the project. As explained by the Commission, "In a normal general rate case, the utility must demonstrate the reasonableness of every dollar in its revenue requirement."[803] SCE failed to meet its burden for justifying this project, by only providing a one-page cost estimate[804] and failing to provide any contracts, invoices or documentation to support the proposed costs. Accordingly, SCE's costs are speculative, and in light of the fact that it significantly underspent its authorized budget for the project in the last GRC cycle, it is un just and unreasonable to continue authorizing funds for the project.

[802] Ex. TURN-10 (Defever), p. 17, Table 13.

[803] D.96-12-066, 1996 Cal. PUC LEXIS 1111, *10-11, 69 CPUC2d 691 (Cal. P.U.C. Dec. 9, 1996).

[804] Ex. TURN-10 (Defever), p. 17: 9-11, referencing TURN-SCE-030 Q48, see Ex. TURN-10-Atch-1, pp. 11-12.

32.1.2.2 Rector Maintenance and Test Building

SCE's request for the Rector Maintenance and Test Building is similar to the Devers project discussed above in that SCE was authorized $11.035 million for the project in the 2018 GRC Decision but spent less than $700,000 through 2018.[805] It is inappropriate for ratepayers to provide funds for a project, and then be asked to again provide the funds for essentially the same scope of work when the Company fails to complete the project in the prior rate case cycle.

Similar to the discussion regarding the Devers Maintenance and Test Building, SCE also fails to appropriately justify its forecast for the project. TURN asked SCE to provide support such as invoices, bids, and contracts for the project but SCE failed to provide the requested documents.[806] This is especially troubling given that SCE claims, "the project is in the middle of construction"[807] which indicates SCE should have bids and contracts for the project. SCE has not justified its costs, coupled with the fact that it significantly underspent its authorized budget for the project in the last GRC cycle, it is unjust and unreasonable to continue authorizing ratepayer funding for the project.

33. POLICY, EXTERNAL ENGAGEMENT AND RATEMAKING

33.1 Overview

33.2 Develop and Manage Policy and Initiatives

33.3 Professional Development and Education

33.4 Other Issues

[805] Ex. TURN-10 (Defever), pp. 17-18: 18-19 & 1.

[806] *Id*. at p. 19: 5-7.

[807] Ex. SCE-17, V5 (Neal), p. 23: 13-14.

34. GRC-RELATED BALANCING AND MEMORANDUM ACCOUNT PROPOSALS

The Commission must reject SCE's proposed new balancing accounts, and continue to require SCE to demonstrate reasonableness of above-authorized costs before permitting rate recovery of such costs.

SCE proposes to create three new balancing accounts in this proceeding. Two of the accounts would serve to record the costs of all system hardening and enhanced operational practices associated with its wildfire risk mitigation activities and vegetation management activities (the Wildfire Risk Mitigation Balancing Account (WRMBA) and the Vegetation Management Balancing Account (VMBA)). SCE also seeks a third new balancing account (the Risk Management Balancing Account (RMBA)) for recording payments made for wildfire insurance and related risk-transfer mechanism.[808]

The Commission must reject SCE's proposals for these new two-way balancing accounts. In each case, the utility's proposal represents a fundamental shift of cost recovery risk from the utility to its customers. Under existing ratemaking for nearly all of the costs that SCE would record in the new balancing accounts, SCE already has an opportunity to achieve rate recovery of its recorded costs, even if the recorded costs exceed a previously-authorized forecast.[809] But any such rate recovery would require a demonstration of reasonableness of the above-authorized costs, consistent with Section 451 of the Public Utilities Code. Under SCE's proposals here, there would be no reasonableness review of above-authorized costs. As a result, ratepayers

[808] Ex. SCE-07, Vol. 1A, p. 32.

[809] The one exception is SCE's "routine" vegetation management expenses. To TURN's knowledge, that subset of vegetation management expenses has in the past been authorized on a forecast basis, and is not subject to program-specific memorandum account or balancing account treatment at present.

would be at greater risk of paying rates that include above-authorized costs that were never determined to be reasonable.

TURN recognizes that, under PU Code Section 8386.4, the utility is permitted to record in a memorandum account "costs incurred for fire risk mitigation that are not otherwise covered in the [utility's] revenue requirements." But any expanded cost recovery opportunity under the statute comes with a critical restriction: "The commission shall review the costs in the memorandum accounts and disallow recovery of those costs the commission deems unreasonable."[810] SCE's proposals here would eliminate any reasonableness review for above-authorized costs, and substitute the lesser "review for compliance" that takes place in ERRA Review proceedings. In the face of the clear statutory language directing a reasonableness review of any above-authorized costs, SCE's proposal is impermissible.

To achieve a ratemaking approach that is consistent with Section 8386.4, the Commission should simply follow the legislative direction from that section and permit SCE to continue to record above-authorized amounts in a memorandum account, subject to after-the-fact reasonableness review. Such ratemaking would provide SCE an opportunity to recover the entire amount spent, even if the recorded spending exceeds the amount the Commission authorizes for rate recovery here; the only limitation would be that SCE has to establish the reasonableness of the above-authorized spending. Even better, the Commission could achieve such ratemaking by simply maintaining the *status quo* to the extent the costs are recorded in memorandum accounts. Alternatively, the Commission could authorize one-way balancing accounts that would apply to the spending level authorized in this GRC, and companion memorandum accounts for purposes

[810] Section 8386.4(b)(1).

of recording any above-authorized spending. Under either approach, the above-authorized spending would be subject to an after-the-fact reasonableness review, either in SCE's next GRC or in a separate application.

TURN's General Criticisms of SCE's Balancing Account Proposals and General Recommendation

SCE's Proposed Balancing Accounts Are Flawed, Both As Originally Proposed And As Modified In Rebuttal Testimony, and Must Be Rejected.

As proposed in its direct testimony, SCE's new balancing accounts would eliminate reasonableness reviews of any above-authorized costs. The utility acknowledges as much, describing its proposal as permitting it to recover above-authorized costs "with no after-the-fact reasonableness review of costs spent in excess of the forecast adopted in this proceeding."[811] Instead, the above-authorized amounts would only be "reviewed for compliance" in the utility's annual Energy Resource Recovery Amount (ERRA) review proceeding.[812] The Commission has recognized that the "compliance review" performed in an ERRA proceeding does not rise to the level of a "reasonableness review."[813] Thus, the upshot of SCE's proposal is that costs above the level authorized in this GRC could be recovered in rates without any determination of reasonableness.[814] And for the cost categories that would fall within SCE's new balancing

[811] Ex. SCE-18, Vol. 1, p. 12.

[812] Ex. SCE-07, Vol. 1A, p. 33.

[813] "The Commission is required to perform a compliance review of the ERRA balancing account and related regulatory accounts and non-ERRA accounts. A compliance review considers whether a utility has complied with all applicable rules, regulations, opinions, and laws, while a reasonableness review evaluates not only a utility's compliance, but also whether the data or actions resulting from, for example, the calculation of a forecasted expense, are reasonable, based on the methods and inputs used." D.18-10-031 (SCE 2016 ERRA), p. 3.

[814] Ex. TURN-01 (Finkelstein Testimony), p. 25.

accounts, this would represent a change in ratemaking practice and loss of ratepayer protection. Through 2020, SCE either has no opportunity to recover above-authorized spending amounts (in the case of "routine" vegetation management), or can only recover above-authorized amounts after demonstrating the reasonableness of those amounts. For the 2021 test year and thereafter, those cost recovery restrictions would no longer apply, and the utility would merely need to satisfy a lesser "compliance review."

SCE's rebuttal testimony reiterated and reaffirmed that its primary position remains that the Commission should adopt two-way balancing accounts, and find that "after-the-fact reasonableness review of costs in excess of the forecast adopted in this proceeding is unnecessary."[815] But the utility presented alternative positions that would provide for a reasonableness review of above-forecast spending recorded in the new balancing accounts, but only to the extent the spending exceeds a "soft cap" set at 120% of the adopted forecast, with the excess spending calculated over the entire rate case cycle, and the reasonableness review conducted by a Tier 3 advice letter, rather than in an application proceeding.[816]

The Commission should not adopt SCE's alternative proposals. Contrary to Commission Rule 12.5 which makes clear that settlements may not be cited as precedent, the utility has cherry-picked the settlements from two proceedings and cobbled together a ratemaking proposal that continues to lack key ratepayer protections. Under Rule 12.5, SCE's reliance on non-precedential settlements should be given no weight by the Commission.

[815] Ex. SCE-18, Vol. 1, pp. 12 and 17.

[816] *Id.*, pp. 13-14 (for the WRMBA), and p. 17 (for the VMBA). SCE's rebuttal proposed no alternative for the RMBA.

Even if the Commission were to permit SCE to rely on the prior settlements, it should still reject the utility's revised position, While SCE characterizes the new position as "logically indistinguishable" from the outcomes under the two settlements, there are, in fact, important distinctions that should convince the Commission that a different outcome is called for here. In the Grid Safety & Resiliency Program (GS&RP) settlement adopted in D.20-04-013, the cap was set at 100% of the authorized spending for most programs, and at 115% for the covered conductor program. There was also a funding cap based on the number of trees to be removed. Importantly, the settlement also included a unit cost element, with SCE required to make a reasonableness showing if the settled average unit costs were exceeded for most programs, or if the covered conductor unit costs exceeded 115% of the settled amount, or if the average unit costs for tree removal fell in the 100% to 125% range (with SCE precluded from rate recovery of tree removal costs that exceed 125% of the average settled costs.[817] In addition, any reasonableness review would occur either in the next GRC or through a separate application.[818] Setting the trigger for reasonableness reviews at 100% of the authorized spending for most programs, including unit cost provisions that could also trigger reasonableness reviews, and conducting the reasonableness reviews in an application proceeding appear to have satisfied the Commission that, on balance, the ratemaking proposed in the settlement is reasonable in light of the whole record developed in that proceeding, consistent with law, and in the public interest, the standard for settlement approval set forth in Rule 12.1(d). Each of those important elements is

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[817] D.20-04-013, pp. 18-19.

[818] *Id.*, p. 33, and Ordering Paragraph 24.

missing from SCE's proposals revealed in rebuttal testimony, making the "logically indistinguishable" label inapposite.

The pending proposed settlement from PG&E's test year 2020 GRC (A.18-12-009) contains similar ratepayer protections that are not included in SCE's rebuttal testimony proposal, such as a lower "soft cap" for the overall spending on most programs, and the inclusion of a unit cost trigger in addition to an overall spending trigger.[819] And while the PG&E GRC settlement would permit the reasonableness review of above-authorized spending to occur via a Tier 3 Advice Letter, it is not yet known if the Commission agrees that reliance on a Tier 3 Advice Letter arising from a GRC decision is permissible under Section 8386.4(b), given the statute's explicit reference to a general rate case or an application proceeding as the forum for such review.[820]

Finally, even if SCE were correct that the proposed outcomes in the two settlements are "logically indistinguishable" from its rebuttal testimony proposals, the Commission should find inappropriate the utility's attempt to cherry-pick those settlements. Taking any element of a proposed settlement out of the context of the entire settlement ignores the interrelationship of the trade-offs achieved across the range of settled issues, often a key characteristic of a proposed settlement. For example, the inclusion of a Tier 3 Advice Letter process for the reasonableness review in the PG&E GRC settlement is tied not only to the greater ratepayer protection achieved through the unit cost trigger element within that section of the settlement, but to the overall outcomes that would be achieved under the wide-ranging GRC settlement. This is part of the

[819] TURN Response to SCE DR-14 (included in Appendix B to Ex. SCE-18, Vol. 1), p. B-2.
[820] As of the date of this brief, no Proposed Decision has yet issued on the PG&E GRC settlement.

reasoning underlying Rule 12.5, which directs that the settlement is only binding in the proceeding in which it is adopted, and an adopted settlement "does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding."

In sum, the Commission should conclude that SCE's alternative proposals presented for the first time in its rebuttal testimony are not reasonable under the circumstances in this proceeding, and should not be adopted.

TURN General Recommendation – The Commission Should Either Retain Existing Ratemaking Mechanisms, or Adopt Modified Balancing Accounts To Provide For Reasonableness Reviews of Any Above-Authorized Spending.

TURN's testimony recommended rejection of SCE's proposed balancing accounts altogether.[821] The upshot of adopting this recommendation would be a continuation of the current ratemaking mechanisms, with SCE continuing to record its incremental costs in the existing memorandum accounts.[822] And consistent with currently authorized ratemaking, future recovery of any above-authorized costs would require SCE to demonstrate the reasonableness of such costs in its next GRC or another application proceeding. This remains TURN's primary recommendation on this issue.

TURN's testimony also presented alternative balancing account recommendations, including a one-way balancing account for wildfire mitigation cost recovery, and a one-way balancing account for the Hazard Tree Mitigation Program, with a focus on the need to ensure authorized funds not used for the programs be returned to ratepayers rather than diverted to other

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[821] Ex. TURN-01 (Finkelstein Testimony), pp. 24-28.

[822] Ex. TURN-02-Atch-1-E (Borden-Finkelstein Testimony Attachments), p. 171 (SCE Response to TURN DR-01, Question 6.b. in WSD-001).

utility purposes.[823] Upon further reflection and consideration of the evidentiary record developed here, TURN acknowledges that a strict one-way balancing account approach for these categories may not be permitted under Public Utilities Code Section 8386.4. If such costs are deemed part of the utility's Wildfire Mitigation Plan, the utility is permitted to establish "a memorandum account to track costs incurred for fire risk mitigation that are not otherwise covered in [its] revenue requirements," with rate recovery of such costs subject to reasonableness review.[824] A one-way balancing account, without more, typically precludes any opportunity for rate recovery of above-authorized spending.

Therefore, TURN clarifies its alternative recommendations as follows: If the Commission opts to adopt a balancing account to cover any of the three cost categories for which SCE is seeking new balancing accounts, instead of the two-way balancing account SCE has proposed for each, it should adopt a one-way balancing account and a companion memorandum account. The one-way balancing account would track spending up to the amount the Commission authorizes as a reasonable forecast in this proceeding and includes in the GRC revenue requirement; if the recorded spending is below the authorized figure, the difference would be refunded to ratepayers. The companion memorandum account would track spending above the authorized amount, and the utility would be required to demonstrate the reasonableness of the above-authorized spending, either in its next GRC or in a separate application proceeding, in order to recover those above authorized amounts in rates.

[823] Ex. TURN-02 (Borden-Finkelstein Testimony), pp. 30 and 45.
[824] Section 8386.4(b)(1).

Reliance on a memorandum account for the tracking and subsequent reviewing of above-authorized spending is consistent with the approach the Commission has taken in the two most recent PG&E gas transmission and storage (GT&S) rate cases. In D.16-06-056 (PG&E's Test Year 2015 GT&S), the Commission adopted a forecast for hydrostatic testing costs that was below the utility-proposed figure, but also approved a memorandum account to track expenses above the authorized expense level. PG&E would then have an opportunity to recover the tracked amounts in a formal application proceeding, to the extent it could demonstrate the reasonableness of those amounts.[825] Similarly, for the array of programs within PG&E's Transmission Integrity Management Program (TIMP), the Commission rejected the utility's proposal to replace the existing one-way balancing account with a two-way balancing account. However, it recognized the utility might face new transmission integrity management statutes or rules that could result in additional costs, and allowed PG&E to track such costs in a memorandum account created for that purpose.[826]

In D.19-09-025 (PG&E's Test Year 2019 GT&S), the Commission adopted a similar approach for Compression and Processing (C&P) expenses, with a new memorandum account established to track above-authorized amounts, particularly for compliance with new regulations.[827] The Commission adopted a forecast for upgrades under the In-Line Inspection Program, but provided a memorandum account for recording above-authorized spending associated with upgrades that exceeded the authorized pace.[828] The one-way balancing account

[825] D.16-06-056, pp. 62-63.

[826] *Id.*, pp. 253-254.

[827] D.19-09-025, pp. 102-104.

[828] *Id.*, pp. 137-138.

and memorandum account previously adopted for TIMP was retained, as the Commission found the mechanism reasonable for ensuring a sufficient opportunity for PG&E to recover costs incurred due to unidentified potential regulatory changes.[829] And for the Root Cause Analysis and Locate and Mark programs, the Commission also directed use of memorandum accounts to track above-authorized spending for later reasonableness review.[830]

The Commission should also require appropriate sub-accounts within each one-way balancing account and associated memorandum account to ensure the ability to track and, as appropriate, compare authorized and recorded spending at a more granular level. For example, SCE's vegetation management spending subject to this GRC includes four separate programs for which the utility's proposed spending totals $211 million, of which $56 million is the forecast for the Hazardous Tree Management Program (HTMP).[831] The Commission's review of above-authorized spending must permit comparison not only of the total recorded spending to the total forecast subject to the VMBA, but also the recorded versus authorized amounts for each program within the balancing account. To illustrate, assume the Commission adopts a total forecast of $200 million for the four programs covered by the VMBA, based on program-specific forecasts of $50 million each. Further assume that SCE records costs of $40 million each for three of the four programs, but $100 million for the fourth. If the Commission only considers the cumulative total, it would appear that only $20 million of SCE's recorded spending is subject to reasonableness review.[832] But the above-authorized spending on the fourth program is actually

[829] *Id.*, p. 159.

[830] *Id.*, pp. 166-167 and 224-225.

[831] Ex. SCE-13, Vol. 6 E2 (Jocelyn), p. 3, Table I-1.

[832] ($40 * 3) + $100 = $220; $220 - $200 = $20 million.

$50 million above the authorized figure. The Commission's reasonableness review should focus on the full amount of above-authorized spending for the fourth program. To enable this, the Commission should require that the accounts record costs in a manner that permits a comparison of the overall spending levels, but also the program-specific levels to the amount authorized for that program.

To summarize, simply maintaining SCE's existing ratemaking mechanisms would provide the utility with a sufficient opportunity to recover above-authorized amounts incurred during this GRC cycle, subject to SCE successfully establishing the reasonableness of such amounts. If the Commission opts to authorize balancing accounts for any or all of the activities for which SCE has requested them, it should adopt each as a one-way balancing account up to the amount authorized as reasonable in this proceeding, and provide for a companion memorandum account for purposes of permitting SCE to record any above-authorized spending. Recovery of any amount recorded in the companion memorandum account would be subject to a reasonableness review in either SCE's next GRC or in a separate application proceeding.

34.1 Wildfire Risk Mitigation Balancing Account

TURN's testimony called upon the Commission to reject SCE's proposed WRMBA for two reasons. First, it clearly violates Section 8386.4(b), which requires a memorandum account for purposes of tracking costs incurred for fire risk mitigation that are not otherwise covered in SCE's revenue requirement, and a reasonableness review of those costs.[833] Second, it would render nearly meaningless the Commission's adoption of a reasonable forecast in this proceeding. Should SCE's recorded costs exceed the adopted forecast, it would still recover the

[833] P.U. Code Section 8386.4(b)(1).

full amount spent, without regard to the reasons (or lack thereof) explaining the cost overruns.[834] Adoption of the WRMBA as proposed by SCE would effectively serve to assign to ratepayers the entire cost recovery risk, rather than limiting that risk to costs demonstrated to be reasonable, with the utility and its shareholders bearing the risk of unreasonable costs.[835]

In its rebuttal testimony, SCE presents three reasons why it is appropriate that there be no reasonableness reviews for above-authorized spending for activities the costs of which are recorded in the WRMBA. First, SCE argues that "statute prohibits SCE from shifting funds authorized for wildfire mitigation plan-related spending," which it suggests should moot TURN's concern about the potential for such fund shifting.[836] However, TURN's stated concern was not limited to potential fund shifting, but also addressed the need for cost control in WMP-related activities, which is a discipline that an after-the-fact reasonableness review helps promote.[837]

SCE's second reason for eliminating reasonableness reviews going forward is "the scope of the wildfire mitigation activities themselves are reviewed and in SCE's view approved in the [Wildfire Mitigation Plan (WMP)] process." The utility expands on this point, arguing "the cost of activities performed in compliance with the approved WMP should be considered *per se* reasonable and recoverable from customers."[838] The Commission has already firmly rejected this argument. In R.18-10-007, the WMP rulemaking proceeding, SCE had doggedly taken a similar

[834] Ex. TURN-02-E (Borden/Finkelstein Testimony), p. 28.

[835] Ex. TURN-01 (Finkelstein Testimony), p. 25.

[836] Ex. SCE-18, Vol. 1, pp. 12-13.

[837] Ex. TURN-02-E (Borden/Finkelstein Testimony), p. 29.

[838] Ex. SCE-18, Vol. 1, p. 13.

position. And in D.19-05-036, the Commission made very clear that it did not share the utility's view, or any view that suggested approval of a Plan constitutes a determination on cost, reasonableness, or prudency.[839] Instead, it explained very clearly that the approval of a utility's WMP is not "dispositive of an IOU's ultimate cost recovery for the operations and maintenance costs of … steps to mitigate wildfire risk."[840] SCE should not be permitted to revive this failed argument here.

For its third reason, SCE asserts that "a two-way balancing account is appropriate for new activities whose actual costs can differ from the recorded data [underlying the forecast]."[841] TURN submits that on this point, SCE has it precisely backward; for new activities with greater uncertainty underlying the cost forecasts presented here, it is especially critical that the Commission review any above-authorized spending for reasonableness. The Commission reached a similar conclusion in PG&E's recent GT&S rate case with regard to the potential for above-authorized spending due to costs incurred "to comply with unidentified potential regulation changes that could impact the scope of [Transmission Integrity Management Program] work during the instant rate case period."[842]

34.2 Vegetation Management Balancing Account

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[839] D.19-05-036, p. 38.

[840] *Id.*, p. 20; *see also* Conclusion of Law 3 ["SB 901 does not provide that Commission approval of a WMP is dispositive of whether the WMP filer acted reasonably and prudently when the filer seeks recovery of WMP-related costs."]

[841] Ex. SCE-18, Vol. 1, p. 13.

[842] D.19-09-025 (PG&E test year 2019 GT&S), p. 159, and Finding of Fact 82.

SCE's proposed VMBA would cover "routine and wildfire-related vegetation management activities."[843] The utility does not contend that a balancing account is warranted because the vegetation management costs are beyond its control. Rather, it describes a "comprehensive transformation" of its vegetation management program, with a newly-developed reliance on risk management practices to evaluate issues and prioritize work. SCE also cites "forecast uncertainty around SCE's [Hazard Tree Mitigation Program, or HTMP] and the new requirements for expanded clearing distances in [High Fire Risk Areas, or HFRA], which can impact the final scope of work for those programs and their associated costs."[844] The fact that costs may be higher going forward than they were in the past is not a sufficient justification for two-way balancing account treatment, particularly if such treatment means above-authorized spending is not subject to reasonableness review.[845] And, again, to the extent the recorded costs exceed the authorized amounts for the "new" elements of vegetation management activities, or due to the "forecast uncertainty" of HTMP, that represents further reason to require an after-the-fact demonstration of reasonableness should the utility spend more than is authorized here. If there is a legitimate purpose to be achieved through consolidation of the existing accounts into a single ratemaking account,[846] the Commission should create a consolidated account while still preserving reasonableness reviews of above-authorized spending.[847]

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[843] Ex. SCE-18, Vol. 1, p. 14.

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

[845] Ex. TURN-01 (Finkelstein Testimony), pp. 26-27.

[846] Ex. SCE-07, Vol. 1A, p. 33; Ex. SCE-02, Vol. 6, p. 2.

[847] Ex. TURN-01 (Finkelstein Testimony), p. 27. As described further below, the accounts should be maintained at a sufficiently granular level to permit review of each program included in the balancing account.

SCE's rebuttal testimony sought to characterize TURN as having taken two "incongruous" positions by acknowledging that vegetation management activities are relatively low cost as compared to the covered conductor program, but also arguing that an increase in vegetation management costs does not alone sufficiently justify two-way balancing account treatment.[848] There is nothing incongruous about TURN's positions. It is entirely possible for SCE to spend unreasonable amounts on its vegetation management programs even though, when compared to other programs, vegetation management activities are relatively low cost. And it is the risk of SCE spending unreasonable amounts that should remain with the utility and its shareholders. Under SCE's two-way balancing account proposal, that risk would be inappropriately shifted to ratepayers.[849]

34.3 Risk Management Balancing Account

The RMBA is needed, according to SCE, because wildfire liability insurance costs are "significant, difficult to forecast accurately, and beyond the control of SCE."[850] TURN agrees that the costs are significant, and that SCE has failed to forecast them accurately in recent years. But key elements are and will remain within the control of SCE. After all, the utility assembles the portfolio or "tower" of policies that achieve its total coverage in any given policy period, and the Commission should presume that the utility has at least some control over the mix of policies and coverages included in that portfolio. Furthermore, SCE has indicated that, going forward, it may rely for the first time on alternative risk transfer instruments such as catastrophe bonds, and

[848] Ex. SCE-18, Vol. 1, p. 16.

[849] Ex. TURN-01 (Finkelstein Testimony), p. 25.

[850] SCE-07, Vol. 1A, p. 34.

self-insurance at levels far greater than it has in the past. The decision whether or not to rely on such instruments would be entirely within the utility's control.[851] And the utility describes self-insurance as an option that might be appropriate where "wildfire insurance is overpriced in the market relative to its true actuarial value," but has not presented testimony or workpapers that identified or defined the process for determining the "true actuarial value" for such purposes.[852] SCE's proposal to record wildfire liability insurance costs in the RMBA, with only "compliance" reviews going forward, would mean any decision to pursue self-insurance would likely never be subjected to a reasonableness review.

The RMBA is particularly inappropriate because it follows so closely on the heels of the creation of the Wildfire Expense Memorandum Account (WEMA) which exists, in part, to permit the utility to track and later seek rate recovery of above-authorized wildfire liability insurance costs. Before establishment of SCE's WEMA, if the utility's recorded liability insurance costs exceeded the amount authorized in its GRC, the utility typically bore the entire risk of such overruns. Once SCE's WEMA went into effect, the risk of above-authorized costs was assigned to SCE's customers, subject to the requirement that SCE demonstrate the reasonableness of those costs. Now SCE seeks a two-way balancing account to replace the relatively recently-adopted insurance-related elements of WEMA and eliminate the associated reasonableness review protection. In short, SCE's response to a period of "extreme volatility and uncertainty" in which its wildfire liability insurance expense forecast has mushroomed from $92 million in the 2018 GRC to $624 million for the 2021 test year is to implement a change that

[851] Ex. TURN-01 (Finkelstein Testimony), p. 27.

[852] Ex. SCE-17, Vol. 2, p. 27; Ex. TURN-63 (SCE Responses TURN DR 97), Response 10.b, p. 8.

would reduce the Commission's scrutiny of such costs.[853] TURN submits that these are conditions that cry out for at least the level of scrutiny available through the reasonableness review process associated with the WEMA, not the far lesser review "for compliance" that would occur in the ERRA.[854]

34.4 Other Balancing and Memorandum Accounts

35. OTHER RATEMAKING PROPOSALS

35.1 Renewed Requests for Project Funding

35.2 Review of Mobilehome Park Costs

36. OTHER OPERATING REVENUE

36.1 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.[855] Since that time, SCE shareholders have been rewarded with more than $1.126 billion of revenues while ratepayers received $545.1 million,[856] even though ratepayers paid for the assets *and* paid shareholders for the returns on the rate base. Because Edison Carrier Solutions ("ECS") generates the vast majority of revenues for NTP&S,[857] TURN focuses most of its analysis and recommendation below on ECS, but the issues identified below apply to most, if not all of SCE's NTP&S offerings.

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[853] Ex. SCE-06, Vol. 2, p. 41.

[854] Ex. TURN-01 (Finkelstein Testimony), pp. 27-28.

[855] D.99-09-070, Attachment A, pp. 3-4.

[856] Ex. TURN-06, p. 21, citing DR TURN-SCE-063, Question 3, Exhibit A.

[857] Ex. TURN-06, p. 21, citing Periodic Reporting of Non-Tariffed Products and Services for 2018. In 2018, Use of Communications and Computing Systems generated $47.166 million.

36.1.1 SCE's Has Been Running a Subsidized Business Within the Utility that Is More Profitable Than the Top Companies in the Sector

SCE has been running a subsidized and less-regulated business within the utility because ECS has failed to allocate all costs associated with its NTP&S offerings to shareholders. As a result, ECS freely uses activities and resources funded by ratepayers, which allows the shareholder to enjoy a level of profitability that is unheard of and unmatched by even the top companies in the sector.

ECS is an organization with more than 140 personnel that focuses solely on generating revenues for non-tariffed products and services.[858] SCE claims that ECS is a department within the Customer Service Organization Unit,[859] but in reality, its functions and purposes are nothing like the utility's. All ECS positions are "100% funded by shareholders" and "fully dedicated to ECS matters."[860] In other words, all ECS personnel are fully dedicated toward the generation of revenues, of which 90% is given to shareholders and 10% to ratepayers. After repeated attempts, TURN finally uncovered that ECS does not (and most likely has never) credited or reimbursed the utility or ratepayers for use of the utility's resources.[861] In fact, SCE could not even describe the accounting mechanism that would be used if such a transaction were to occur,[862] most likely because ECS, a business that provides 90% of revenue to shareholders, *has never compensated the ratepayer or the utility for use of SCE's resources.*

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[858] Ex. TURN-06, p. 25, citing DR TURN-SCE-046, Question 6.

[859] Ex. TURN-06, p. 25, citing DR TURN-SCE-046, Question 3.

[860] Ex. TURN-06, p. 25, citing DR TURN-SCE-046, Question 6.

[861] Ex. TURN-06, p. 25, citing DR TURN-SCE-063, Question 4 Supplemental.

[862] Ex. TURN-06, p. 26, citing DR TURN-SCE-063, Question 4, Question 4 Supplemental.

In fact, SCE readily admits that it does not compensate ratepayers or the utility for ECS's use of utility resources.[863] SCE claims that it uses the "but for" test to determine that "support for ECS does not increase SCE's costs for shared services."[864] Despite the fact that it is inappropriate for SCE to be the sole decision-maker for this determination due to conflict of interest (discussed below in Section 36.1.2), this assertion is outrageous and unreasonable. Below are select examples of ratepayer funded resources that have been freely provided to ECS (while ratepayers only receive 10% of revenues):

- ECS has more than 140 personnel and currently has 20 vacancies, yet it does not have its own Human Resources personnel and instead uses SCE's resources.[865]
- ECS does not pay rent or office related expenses (including utilities) for its more than 140 personnel.[866]
- ECS does not have an IT department to support the IT needs but instead uses SCE's resources.[867]
- ECS does not have a Legal or Regulatory department. When SCE litigated Application 17-02-001, it used ratepayer funded resources to fight for the

[863] Ex. TURN-06, p. 26, citing DR TURN-SCE-063, Question 4 Supplemental.
[864] Ex. TURN-06, p. 26, citing DR TURN-SCE-046, Question 5.
[865] Ex. TURN-06, p. 26, citing DR TURN-SCE-046, Question 6 Org Chart.
[866] Ex. TURN-06, p. 26, citing DR TURN-SCE-046, Question 2 Attachment.
[867] *Id.*

continuation of a sharing mechanism that provides 90% of revenue to shareholders.[868]

The above list is by no means comprehensive. SCE often claims that the costs for providing NTP&S are not included in the GRC,[869] but it is not able to provide examples or documentation showing where costs have been removed from the GRC to account for these costs.[870] In short, for close to two decades, ECS has been freely using ratepayer funded resources to generate revenue, 90% of which is given to shareholders. It is not reasonable for a business with more than 140 personnel with annual revenues greater than $38 million to have no expenses for HR, rent, utilities, IT support, and others. Unsurprisingly, due to all the subsidized expenses, shareholders have enjoyed tremendous profit margins at levels unheard of in the telecommunications sector and higher than the top companies in the sector.

By SCE's own measure, shareholders have enjoyed an average *net margin* for NTP&S of 23.2% in the last five years:[871]

	2014	2015	2016	2017	2018	Average
Shareholder Gross Revenue ($M)	$55.1	$56.6	$53.8	$54.8	$52.3	$54.5
Shareholder Net Profit ($M)	$15.3	$17.1	$11.9	$11.6	$7.8	$12.7
Shareholder Net Margin (%)	**27.8%**	**30.2%**	**22.1%**	**21.2%**	**14.9%**	**23.4%**

[868] A.17-02-001, TURN Reply Comments (November 13, 2017), p. 5. SCE claims that shareholders paid for outside counsel in that proceeding, but SCE also used internal Legal and Regulatory resources that were funded by ratepayers. This fact is undisputed.

[869] Ex. TURN-06, p. 27, citing DR TURN-SCE-063, Question 4.

[870] *Id.*

[871] Ex. TURN-06, p. 27, citing DR TURN-SCE-063, Question 3 Exhibit A.

By comparison, the median net margin for the Telecommunications Services industry is 3.84%.[872] Over the last ten years, AT&T's median net margin was 8.51%,[873] and Verizon's median net margin was 9.98%.[874] Yet, using assets primarily paid for by ratepayers and resources funded by ratepayers, SCE's shareholders have been able to achieve average net margin of 23.2%, over 130% *more* than Verizon and AT&T!

It is worth noting that SCE likes to tout the "fact" that ratepayers have received 74% of "net benefits" since 1999. SCE's claim of "net benefits" for ratepayers is a complete red herring because it does not account for the fact that ratepayers paid for the assets being used to generate the revenue, as well as all the ECS-related expenses discussed above that act as free subsidies to the business. Hence, the "net benefits" measure is meaningless for ratepayers. Meanwhile, "net benefits" likely underestimates the net margins for shareholders because it does not account for the returns that shareholders receive as a result of the assets used being in rate base. Even without accounting for the return on rate base, the net margin for shareholders, as discussed above, is already shockingly high and likely impossible if ratepayers had not paid for the assets and subsidized the expenses.

In its rebuttal, SCE claims that the six-year average net margin for ECS is 1.2%.[875] Yet, an examination of SCE's analysis reveals that it is nonsensical, arbitrary, and contradicted by

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[872] Ex. TURN-06, p. 27, citing https://www.gurufocus.com/term/netmargin/NYSE:VZ/Net-Margin-/Verizonmmunications

[873] Ex. TURN-06, p. 27, citing https://www.gurufocus.com/term/netmargin/NYSE:T/Net-Margin-/ATT

[874] Ex. TURN-06, p. 28, citing https://www.gurufocus.com/term/netmargin/NYSE:VZ/Net-Margin-/Verizonmmunications

[875] Ex. SCE-18 V01, p. 61.

SCE's own statements. First, SCE arbitrarily deducts the GRSM threshold as an expense for ECS, which reduces the net margin by more than 21% right off the top.[876] The GRSM threshold is not an expense, nor is it attributable to Telecommunication Services. Second, under this manufactured analysis, SCE shareholders would have lost money in three of the last six years, yet SCE has ferociously fought to preserve the status quo *in every single proceeding* that attempted to re-examine the appropriateness of SCE's NTP&S framework. SCE again vigorously defends the status quo and asserts that any change would "significantly impair shareholder incentive to invest" and would "frustrate SCE's reasonable investment-backed expectation."[877] It is nonsensical and unreasonable to believe that SCE would vigorously defend an NTP&S framework that results in losses in three of the last six years. The Commission should reject SCE's self-serving analysis that claims the net margin for ECS is only 1.2%.

36.1.2 The Inequitable Sharing of Revenues Creates Inappropriate Conflicts of Interests Between Shareholders and Ratepayers

In addition to the inappropriate subsidies by ratepayers to shareholders, the unequitable sharing mechanism also creates inappropriate conflicts of interests. SCE is a utility funded by ratepayers that is supposed to provide services to benefit ratepayers. Yet, it is housing a business (ECS) within the Customer Service Organization Unit with all positions 100% funded by shareholders and fully dedicated toward the generation of revenues, of which 90% is given to shareholders and 10% to ratepayers. Thus, ECS should be considered either 100% or at least 90% owned by the shareholders. When a business that is at least 90% owned by shareholders is

[876] Ex. SCE-50, DR TURN-SCE-087, Question 3

[877] Ex. SCE-18 V01, pp. 48-49.

allowed to exist within a ratepayer funded utility, many inappropriate conflicts of interests are created.

For example, when ECS utilizes resources that are funded by ratepayers, how does the utility resource decide whether to prioritize ECS's request over other requests from the utility? If an HR employee has a great candidate and is trying to fill comparable positions within the utility and ECS, does the HR employee offer the ECS position to the candidate or the utility position? If the HR employee prioritizes the ECS position over the utility's, the HR employee could be making a choice that prioritizes shareholder profits over safety. The same situation comes into play when other utility resources are faced with competing requests from ECS and other parts of the utility. It is inappropriate for shareholders' profit from non-utility service to compete with other priorities of the utility whose mandate is to provide safe and reliable service.

Another clear example of conflict of interest is the fact that SCE is the sole decision-maker in the "but for" test to determine which costs are considered incremental. Every dollar and every use of ratepayer funded resource that SCE does not determine to be "incremental" is a dollar that goes to shareholders' profit. In other words, SCE gets to decide which expenses should be paid for by ratepayers, which results in an increase to shareholder earnings. SCE should not be given the authority to make this determination when the interests of ratepayers and shareholders are clearly conflicted.

Furthermore, because SCE considers ECS a part of the utility, ECS does not have to comply with the Affiliate Transaction Rules, even though it is a business that should be considered at least 90% owned by shareholders. The Affiliate Transaction Rules were implemented in order to “protect consumer interests” and “foster competition.”[878] By not considering ECS an affiliate or separate subsidiary, SCE is able to bypass all the safeguards that were built into Affiliate Transaction Rules to protect ratepayers and the public. As a result, the shareholders have enjoyed tremendous profit margins at ratepayers’ expense, and SCE’s unfair advantage most likely harmed competition instead of the Commission’s goal to foster competition.

In its rebuttal, SCE claims that there is no need to credit or reimburse the utility for ECS’s use of utility resources because SCE has determined that these costs are either not incremental, or the costs are incremental and were never borne by the utility.[879] SCE then asserts that ECS’s use of utility resources is either too small to have an impact or that its employees are properly trained on cost allocation principles.[880] Despite the fact that SCE is the sole decision-maker on what costs are considered incremental,[881] SCE later admitted that it does not have a record of the “but for” tests conducted by SCE for ECS,[882] nor does it keep a record or time log of ECS’s use of utility resources![883] This extraordinarily unreasonable and unjust finding is one of the worst conflict of interests that TURN has ever observed and hence worth repeating here – 1) SCE alone conducts the “but for” test that determines which costs are incremental and should

[878] 1997 Cal. PUC LEXIS 1139, *10.

[879] Ex. SCE-18 V01, p. 59.

[880] Ex. SCE-18 V01, pp. 59-60.

[881] Ex. SCE-18 V01, p. 59. SCE attempted to argue that it is not the sole decision-maker in its rebuttal testimony but was unable to provide what other entities shared the decision-making power. It was only able to state that its decisions are subject to audit and review.

[882] Ex. SCE-50, DR TURN-SCE-087, Question 1.

[883] Ex. SCE-50, DR TURN-SCE-087, Question 4.

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 ECS's use of utility resources, which not only means that an audit of ECS's use of utility resources is impossible, but also that ECS is essentially free to use whatever and however much of utility resources (funded by ratepayers) it desires, which provides 90% of revenues to shareholders.

36.1.3 SCE Should Not Be the Sole Determiner of What Costs Are Incremental and Must Record and Pay for Its Use of Ratepayer Funded Resources

As demonstrated above, SCE's NTP&S framework is ripe with inappropriate conflicts of interests and opportunities for SCE shareholders to take advantage of ratepayers. The Commission must not allow SCE to continue to be the sole determiner of what costs are incremental when SCE is using ratepayer resources to generate profits for shareholders. Every dollar that SCE determines, on its own, to be not incremental is a dollar that ratepayers are paying to the shareholders' bottom line. At a minimum, the Commission should order the following:

1) SCE shall keep a record of each of the "but for" tests that it conducts for its NTP&S offerings that includes sufficient detail to enable the Commission to meaningfully review the logic and calculations supporting SCE's determination. SCE shall include the test records as workpapers as part of its next GRC application.
2) SCE shall keep time logs and other appropriate records of its NTP&S offerings' use of ratepayer funded utility resources that includes sufficient detail to enable the Commission to meaningfully review the use of those

resources. SCE shall include time logs and other records as workpapers as part of its next GRC application.

3) In the next GRC, the Commission intends to review the "but for" tests and SCE's use of ratepayer funded utility resources for its NTP&S offerings. If the Commission determines that costs were inappropriately treated as not "incremental" or otherwise borne by ratepayers, the Commission should disallow those costs. The Commission should also make clear that it will consider modification of the revenue sharing mechanism in the next GRC.

The Commission has repeatedly expressed concerns regarding SCE's NTP&S offerings.[884] In this GRC, TURN has provided compelling examples of unjust and unreasonable subsidies of SCE's NTP&S offerings by ratepayers, demonstrated the inappropriate conflicts of interests created by SCE's NTP&S practices, and presented undisputed evidence that SCE (whether intentional or inadvertently) does not retain sufficient records to allow the Commission and the public to examine whether ratepayer funded resources are inappropriately being used to generate profits for SCE shareholders. The Commission should signal its intention to address and, if appropriate, end this unjust and unreasonable enrichment of SCE shareholders at ratepayers' expense, and at a minimum order SCE to keep records that would allow an examination of these subsidies to be performed.

36.2 Added Facilities Ratemaking

36.3 Other OOR

[884] D.09-03-025, p. 301; D.12-11-051, p. 657; D.15-11-021, p. 382.

37. RATE BASE

37.1 Overview

37.2 Electric Plant, Reserve and Depreciation Expense

37.2.1 Aged Poles

In 2013-2015, SCE undertook an "Aged Pole Program" in which it replaced certain distribution poles without regard to each pole's then-current condition. This is the third SCE GRC in which the Commission has been asked to address rate recovery issues associated with the costs SCE incurred for that program. In SCE's test year 2015 GRC, the Commission disallowed rate recovery for a portion of the costs due to the utility's failure to demonstrate the prudence of the aged pole replacements at the level requested.[885] In SCE's test year 2018 GRC, the Commission denied SCE's request to reverse the disallowance and begin rate recovery of the remaining undepreciated amount for those poles, in part due to SCE's continuing failure to demonstrate the prudence of the Aged Pole Program.[886] Here, SCE asks again that the Commission reverse the previously adopted disallowance.[887] If authorized by the Commission, this reversal would add approximately $14.6 million to the 2021 test year revenue requirement.[888] TURN urges the Commission to deny SCE's request and retain the *status quo* for the 2021 GRC period.

SCE's now asks the Commission to focus not on "whether SCE has provided sufficient evidence to defend the prudency" of the disallowed expenditure, the question specifically posed in both the 2015 and 2018 GRC decisions. Instead, SCE would treat the question as one of "how

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[885] D.15-11-021 (SCE test year 2015 GRC decision), pp. 112-113 and Finding of Fact 131.

[886] D.19-05-020 (SCE test year 2018 GRC decision) , pp. 326-329 and Finding of Fact 269.

[887] Ex. SCE-07, Vol. 02A, pp. 7-8.

[888] Ex. TURN-11 (Marcus-Finkelstein Testimony), p. 1, citing SCE response to TURN DR 8-2.

to place customers in roughly the same position they would have been in had SCE not replaced" the poles associated with the disallowance.[889] The utility's logic is not grounded in or directly responsive to the prior decisions, and the request should be denied for that reason alone. Furthermore, even if the Commission agrees that a calculation of purported ratepayer indifference should be the basis for deciding whether the previously adopted disallowance continues in effect, it should conclude that the poles replaced in the Aged Pole program could reasonably be expected to have remained in service until at least 2024-25, on average. Therefore, the Aged Pole disallowance should remain in effect through this GRC cycle.

37.2.1.1 The Disallowance Adopted and Maintained In The Commission's 2015 and 2018 GRC Decisions Turned On The Utility's Continuing Failure to Demonstrate Prudence, A Failure SCE Repeats Here.

The Commission first reviewed SCE's Aged Pole program in the utility's test year 2015 GRC. The resulting decision made clear that the determination of whether rate recovery of any amount for expenditures to purchase and install poles is a question that "turns on the prudency of the investment decision."[890] The Commission disallowed a substantial portion of the costs of replacement poles under the Aged Pole program because "SCE has not demonstrated that the aged pole replacements are prudent, at the level requested."[891] The amount permitted in rates reflected the Commission's assessment of the number of replaced poles that might have

[889] Ex. SCE-18, Vol. 2, p. 2 [emphasis in original].

[890] D.15-11-021, p. 112.

[891] *Id.* p. 113.

otherwise failed in service, with the disallowance tied to the number of replaced poles that could have continued to serve ratepayers for years to come.[892]

In SCE's test year 2018 GRC, the utility sought to add back to its plant balances the remaining book value of the replacement poles that had been disallowed in the 2015 GRC. The utility argued that the $23 million of lost revenues from the disallowance during the 2015-2017 GRC cycle was itself a sufficient basis to support going-forward recovery of the undepreciated amount for the previously disallowed investment.[893] The Commission disagreed, and maintained the *status quo*. It reiterated the earlier decision's finding that permitting rate recovery for 14,245 replacement poles installed in 2013 and 2014 under the Aged Pole program had reflected the Commission's "recognition that some value was being provided to ratepayers because some poles may have failed in service while also recognizing some could have continued to provide service to ratepayers for many years to come."[894] After reiterating that the earlier decision had tied rate recovery to a demonstration of prudence, the decision noted that SCE's renewed request in the 2018 GRC continued to fall short in that regard:

> SCE still has not answered the question posed prior to D.15-11-021, a precondition before we would allow recovery in rates for expenditures to purchase and install poles. That question turns on the prudency of the investment decision. SCE has not established, indeed has not presented evidence, which would support a finding that it was prudent to replace poles (beyond the poles the Commission authorized) which continued to be used and useful at the time they were replaced. Absent evidence – which we indicated in D.15-11-021 should be provided – supporting the prudence of early replacement of aged poles over higher frequency of inspections or pole reinforcement or other evidence which would support the prudency of the expenditure, we continue to disallow recovery for the

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[892] *Id.*, pp. 113-114.

[893] D.19-05-020 (SCE test year 2018 GRC), pp. 326-327.

[894] D.19-05-020, p. 327.

> 8,586 more aged poles SCE replaced over what the Commission authorized. In disallowing recovery now we note that our decision is based on a failure by SCE to establish the prudence of its expenditure: that it was not prudent to replace the existing poles but also recognize that at some point in time it would become prudent to replace these aged poles.[895]

The 2018 GRC decision's discussion of this issue left SCE an opening for seeking relief here: "we do not preclude SCE from attempting to establish in its next GRC the prudency of replacing the 8,586 poles by a certain date or dates."[896]

Despite the discussion and directives in D.19-05-020, in this GRC SCE again did not meaningfully attempt to demonstrate prudence for the disallowed poles. To the contrary, the utility contends that the 2018 GRC decision did not invite re-litigation of the prudency of the Aged Pole program.[897] As set forth above, the decision contains repeated references to the prudency issue, and the continuing need for SCE to demonstrate an alternative expected replacement date for the disallowed poles. SCE's assertion that prudency is no longer an issue to be addressed seems to represent SCE's tacit admission that the utility is unable to make a prudency showing that might warrant a reversal of the existing disallowance.

The Commission should maintain the disallowance from the 2015 and 2018 GRC decisions due to SCE's ongoing failure to establish the prudence of its investment decision.

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[895] D.19-05-020, pp. 328-329.

[896] *Id.*, p. 329.

[897] Ex. SCE-18, Vol. 2, p. 3.

37.2.1.2 SCE's "Ratepayer Indifference" Showing Supports Continuation of the Disallowance Through the Test Yer 2021 GRC Cycle.

Instead of providing the analysis called for in the 2018 GRC decision, SCE proposes an alternative approach premised on a calculation of ratepayer indifference.[898] In the section that follows, TURN explains why the alternative approach is inappropriate under the circumstances here. However, embedded in SCE's calculations is an answer to the question the Commission described in the 2015 and 2018 GRC decisions, and it also indicates continuation of the disallowance is warranted. SCE's Aged Pole remaining life analysis calculated a 10-year remaining life for the poles and other equipment replaced in 2014-2015.[899] This, then, is SCE's apparent answer to the question posed in D.19-05-020. TURN's testimony presented an alternative analysis demonstrating that a remaining life of at least 12 years is a more reasonable expectation.[900] But even if the Commission were to accept SCE's estimated remaining life, ten years from 2014-2015 would indicate the poles would otherwise have been replaced in 2024-2025. Continuing the disallowance throughout this 2021-2024 GRC cycle is therefore consistent with the Commission's earlier decisions.[901]

[898] Ex. SCE-18, Vol. 2, pp. 5-6.

[899] Ex. SCE-18, Vol. 2, p. 5.

[900] Ex. TURN-11 (Marcus-Finkelstein Testimony), pp. 4-9.

[901] Ex. TURN-11 (Marcus-Finkelstein Testimony), p. 4.

37.2.1.3 SCE's PVRR-Based Approach Is Inappropriate Under The Circumstances Here.

SCE's request to end the Aged Pole program disallowance is premised on the Commission adopting an alternative approach. Rather than establishing the date on which the poles would likely have been replaced absent the program, SCE seeks to assess whether a six-year disallowance (from 2015 through 2020) "is sufficient to make customers whole for the prematurely replaced poles."[902] Using "present value revenue requirement" (PVRR) calculations, the utility asserts that "the costs customers will begin paying in 2021 is [sic] less than what they would have paid for replacement poles had SCE never undertaken the Aged Pole program," and even calculates $22.4 million as an "Excess Benefit received by Customers resulting from disallowance."[903]

SCE contends that its approach with the Aged Pole program is consistent with the approach taken in calculating the "SPIDACalc" disallowance adopted in the 2018 GRC.[904] While there are similarities in the manner in which the calculation is performed, there are material differences between the underlying circumstances and purpose served by the calculation. In the 2018 GRC, TURN had proposed a disallowance for poles SCE replaced prematurely under its pole loading program due to a faulty software program (SPIDACalc). TURN and SCE agreed that the adopted disallowance, if any, should be accelerated such that it would be reflected in the revenue requirement over the three-year 2018 GRC cycle only, rather than removed from rate base for some longer period depending on the duration of the

[902] Ex. SCE-07, Vol. 2A, pp. 7-8.

[903] *Id.*

[904] *Id.*, p. 8.

disallowance adopted by the Commission.[905] The series of agreed-upon PVRR calculations was presented to determine the disallowance figure for a single-GRC cycle. The Commission relied on the other record evidence to resolve the disputed issue regarding the appropriate period for calculating the disallowance amount, then used the PVRR-calculated amounts to determine the corresponding disallowance figure for a single-GRC cycle.[906]

Here, SCE asks the Commission to use the PVRR calculation amount as the basis for selecting a period that is shorter than the ten- to twelve-year period that is supported by other record evidence. SCE cites no prior decision where the Commission determined the appropriate duration of a disallowance based on a theory of "ratepayer indifference" or a PVRR showing. While TURN understands it is an approach that might get SCE the relief it seeks, it is not consistent with the Commission's very clear directives in D.19-05-020 with regard to the Aged Pole program and the showing required of SCE going forward.

The Commission should decline to use SCE's "ratepayer indifference" approach, and instead rely on SCE's and TURN's calculations demonstrating that the prematurely-replaced poles under the Aged Pole program would reasonably be expected to have remained in service an average of at least 10 years (by SCE's calculations) or 12 years (by TURN's calculations). Since the pole replacements occurred in 2014-2015, the existing disallowance should be maintained through this GRC cycle that is scheduled to run through the end of 2024.

[905] D.19-05-020, pp. 337-338.

[906] *Id.*, pp. 340-341.

37.3 Working Capital

37.3.1 Lead Lag Study

37.3.1.1 Fuel & Purchased Power

37.3.1.2 Wildfire Insurance Premiums

37.3.1.3 Goods and Services

TURN recommends a reduction in SCE's working cash request of $15.391 million to reflect a payment lag day forecast of 45-days for PO Goods and Services payments, as opposed to the 40.1 days proposed by SCE.[907] A key element of effectively managing working cash to minimize costs to ratepayers is to fully utilize vendor credit by extending lag days. SCE should carefully manage its working cash in order to reduce its revenue requirement where possible. One action SCE can and should take is to target a PO Goods and Services payment lag in line with top performing global utilities and, at a minimum, consistent with its own best past performance. Based on external benchmarks and SCE's own prior proposals,[908] SCE should be targeting at least 45 Lag Days for its Goods and Services PO Payments in order to minimize costs to ratepayers. PWC Consulting's most recent Working Capital Report indicates median lag days of 59 days for utilities globally,[909] and 55 days for North American corporations

[907] Ex. SCE-54 (Joint Comparison Exhibit), p. 233, TURN-95 updates TURN's calculation based on SCE most recent RO model run.

[908] Ex. TURN-03, p. 33 footnote 102. In SCE's 2015 GRC, SCE forecasted an average PO payment lag of 49.24 days (SCE-10, Vol 02 p. 83), and an overall payment lag *for both PO and Non-PO Good and Services* of 45.19 days (SCE-10, Vol 02, p. 80, Table V-28 Lead Lag Summary 2015, line 11) compared to the 34 days in its original 2021 proposal.

[909] Ex. TURN 03, p. 33, citing PWC, Working Capital Report 2019/20: Creating value through working capital, Unlocking cash in a digital age. p. 13.

generally.[910] SCE achieved payment lags for its PO invoices of 49.5 days, 47.9 days, and 51.9 days in 2014, 2015, and 2016 respectively.[911]

This indicates that SCE should be capable of achieving 45-day payment lags, and in its 2015 GRC SCE forecasted an average PO payment lag of 49.24 days based on its own "Operational Excellence Initiative" through which "SCE endeavored to negotiate improved standard payment terms with its top 200 PO Suppliers."[912] SCE's standard PO payment terms are currently 60-days.[913] However, SCE achieved lag days for 2018 of 40.2 days, and its 2021 forecast uses the same value for base year recorded.[914]

In rebuttal testimony, SCE concedes that "SCE's proposed lag days is lower than in prior rate cases"[915] SCE asserts that its reduction in lag days is due to expedited payments to small businesses and Diverse Business Entities (DBE), early payment vendor discounts, and the use of electronic payments.[916] SCE asserts that small DBE businesses to which it offers expedited payments "make up for 47% of SCE's spending in 2018 are about three days faster than Non-DBEs."[917] While SCE's commitment to "offering a variety of payment options that can help

[910] Ex. TURN 03, p. 33, citing Ibid., p. 16

[911] Ex. TURN 03, p. 33.

[912] Ex. TURN 03, p. 33, citing 2015 SCE GRC, Ex SCE-10, Vol 02, p. 83.

[913] Ex. SCE-18 V02, p. 22: "SCE offers competitive tiered terms with its suppliers, which allows suppliers to receive payment earlier than the standard 60-day term."

[914] Ex. TURN 03, p. 33, citing TURN_DR 017 Q1a-c. Attachment, Summary Tab 2018 Sample of Goods and Services supporting Workpaper SCE, Vol 2, Chapter III, p. 31.

[915] Ex. SCE-18 V02, p. 21.

[916] Ex. SCE-18 V02, p. 21.

[917] Ex. SCE-18 V02, p. 21.

small businesses maintain positive cash flow" is laudable,[918] based on the information provided by SCE, expedited payments should account for only 1.4 days deviation from the 45 day target,[919] while SCE's forecast shows a nearly five-day difference.

SCE also cites a seven-day slower processing time for checks relative to electronic payments as another reason its lag day forecast is significantly higher for this GRC cycle.[920] SCE asserts that "between 2018-2019, check payments to suppliers make up only about 10% of payment activity" with most suppliers transitioned to electronic payments. TURN does not doubt the proliferation of electronic payments and notes that electronic payments not only speed up the receipt of funds by vendors, but they also reduce the cost of payments for SCE relative to paper checks. That said, citing electronic payments as a reason SCE cannot target payment lag days at the level it previously achieved defies common sense. SCE's excuse for its low payment lag days forecast requires the Commission to ignore the fact that the timing of when payments are released to vendors is *entirely in SCE's control* and SCE's standard payment term is not 45-days but *60 days*.[921]

The relative speed of electronic payment processing vs. paper checks is only relevant to SCE's forecast of lag days if SCE intends to continue managing its payment process as if the majority of its payments were still by paper checks. Certainly, when checks were the rule, to target a 45-day payment lag, SCE would have to calculate the payment date including the time

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[918] Ex. SCE-18 V02, p. 21.

[919] 47% of payments x 3 days average reduction in payment lag for vendors receiving expedited payment terms = 1.41 days

[920] Ex. SCE-18 V02, p. 22.

[921] Ex. SCE-18 V02, p. 22: "SCE offers competitive tiered terms with its suppliers, which allows suppliers to receive payment earlier than the standard 60-day term."

for transit, and check clearing, counting back seven days from the payment due date and mailing the check in time to satisfy the targeted payment term. Now, given the "overwhelming majority"[922] of payments are electronic, SCE can easily target a 45-day payment lag by managing when it releases payments to vendors, just like SCE did when the primary means of payment was a check.

Finally, SCE asserts that its forecast "reflects shorter lag days resulting from SCE's participation in Vendor Discount programs that benefit customers by passing on savings through reduced O&M."[923] In other words, SCE asserts that it is trading payment lag days for vendor discounts; thus, the higher the lag days, the lower the vendor discounts which reduce O&M costs charged to ratepayers. Yet, the table below indicates no particular relationship between payment lag days and vendor discounts. Furthermore, SCE's testimony also acknowledges that "Vendor Discount activities were relatively flat between 2014-2017,"[924] but PO Lag Days fluctuated significantly and in a manner that does not appear to impact the level of vendor discounts in any predictable way.

SCE Vendor Discount and PO Lag Days[925]

Year	2014	2015	2016	2017	2018	2021
Vendor Discount	9.7	11.7	10.2	9.9	14.1	11.2
PO Lag Days	49.5	47.9	51.9	43.1	40.2	43.1

922 Ex. SCE-18 V02, p. 22.

923 Ex. SCE-18 V02, p. 22.

924 Ex. SCE-06 V02, p. 16.

925 Ex. SCE-06 V02, p. 16, Table II-2; Ex. SCE-07 V02, Goods and Services Workpapers p. 31; Ex. TURN-03-Atch-1, DR TURN-SCE 17, Question 1.

SCE reports that the recorded benefits from vendor discount programs were $14.1 million in 2018 and are forecasted to be $11.2 million in 2021.[926] SCE's response to TURN's data request confirms that "SCE's calculation of goods and services payment lag days is based on 2018 recorded data, which includes recorded vendor discounts."[927] However, in calculating O&M costs, SCE uses an average value of $11.2 million for vendor discounts over 5 years from 2014 to 2018. This value is $2.9 million lower than the $14.1 million on which SCE calculates working cash, so ratepayers are, in fact, not even receiving the full benefit of vendor discount programs! SCE should certainly not be allowed to use *both* a low estimate of payment lag days due to vendor discounts *and* a low forecast value for vendor discounts.

The Commission should adopt a 2021 PO payment lag forecast of 45-days and adjust SCE's working cash downward by $15.391 million as TURN recommends because: 1) SCE's expedited payments to DBE do not account for a differential of nearly 5 days between SCE's forecast and best practice which SCE has exceeded in the past; 2) SCE's explanation that its forecast of 40.1 days is more reasonable based on an increase in electronic payments defies common sense; and 3) SCE's level of vendor discounts does not appear to be negatively impacted by targeting higher PO payment lag days. If the Commission does not elect to reduce SCE's working cash request to reflect a 45-day PO payment lag, it should adjust SCE's O&M request so that the test year reflects the full value of vendor discounts assumed in the working cash forecast. Allowing SCE to have it both ways would be unreasonable and unjust, resulting in additional cost to ratepayers.

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926 Ex. SCE-18 V02, p. 22.

927 Ex. TURN-69, DR TURN-SCE 113, Question 1.

37.3.1.4 Depreciation Expense

TURN recommends a reduction of $89.149 million in SCE's working capital request based on increasing the depreciation expense payment lag days from zero to 15.2 days,[928] consistent with the fact that depreciation is recognized and "paid" monthly.

Over the past GRC cycles, TURN has made proposals to change the treatment of depreciation in the GRC working cash calculation. Given the magnitude of this GRC request, the finite nature of ratepayer family budgets and SCE's crucial and competing needs for limited GRC funding, TURN feels an obligation to advance recommendations that invite all parties to sharpen their pencils to reduce this request where possible.

SCE disagrees with TURN and cites CPUC Utility Standard Practice U-16, dated September 1968, asserting that "since depreciation immediately reduces the average authorized rate base during the recorded month, SP U-16 correctly applies a zero-day lag. The working cash component is necessary to bridge the gap between when the recovery of costs is received from customers (revenue lag day) and when rate base is reduced (depreciation expense lag day)."[929] SCE asserts that a zero day lag for depreciation "keeps rate base whole until cost recovery is received through the customer bill payment 45.1 days later."[930]

However, both TURN and SCE agree that depreciation is a non-cash expense.[931] As such, depreciation is an accounting construct, and it is recognized as a financial expense for SCE

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[928] Ex. SCE-54 (Joint Comparison Exhibit), p. 234. Ex. TURN-96 updates TURN's calculation based on SCE most recent RO model run.

[929] Ex. SCE-18 V02, p. 24.

[930] Ex. SCE-18 V02 p. 25.

[931] Ex. TURN-69, DR TURN-SCE 104, Question 1.

when recorded. When depreciation is recorded, it "immediately reduces the average authorized rate base during the *recorded* month."[932]

TURN's intention in recommending an increase in the depreciation expense lag from zero to 15.2 days is not for purposes of arbitrarily aligning depreciation payment lag with the accounting cycle, rather it is *because* depreciation, while it may accrue pro rata over the month for purposes of calculating its value, is recognized (and thus, "paid") once per month consistent with a monthly accounting close.[933] Rate base is recorded monthly as well.[934] Thus, under TURN's recommendation, working cash supports the "payment" of depreciation expense when it is recognized on SCE's books, rather than before as SCE proposes. This difference amounts to roughly $90 million more per year in revenue requirement to fund a non-cash expense, or roughly 75 cents per month[935] of payments from residential customers to investors[936] for a non-cash expense. Since debt holders recover their return of and on capital through a separate component related to the cost of capital, maintaining the practice of zero lag days for depreciation can only serve to gratuitously enrich shareholders at the expense of ratepayers.

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[932] Ex. SCE-18 V02, p. 24.

[933] Ex. TURN-69, DR TURN-SCE 104, Question 1.

[934] Ex. TURN-69, DR TURN-SCE 104, Question 1.

[935] Ex. TURN-03-Atch-1, DR TURN-SCE 17, Question 5.

[936] Ex. TURN-69, DR TURN-SCE 104, Question 1. SCE states: "The cash cycle, for depreciation expense, beings with cash outlays by investors for the construction utility infrastructure. The cash cycle ends with recovery of investor cash (through depreciation) when customers pay their bill."

37.3.1.5 Synchronized Interest Adjustments

TURN proposed to include interest on long-term debt in the lead-lag calculation of working cash requirements. However, after reviewing SCE's rebuttal testimony, TURN withdraws this proposal.

37.3.1.6 Taxes Based on Income

TURN recommends a working cash requirement reduction of $265.945 million based on increasing the income tax payment lag days to align with the reality that SCE has not paid federal or state taxes since before the last 2018 GRC cycle, and is unlikely to have any actual tax burden during the 2021 rate case cycle.[937]

SCE states that its tax calculation is predicated on SCE's assumed tax liability based only on revenue and expenses within this GRC proceeding, and that estimated tax payments arising from the federal and state tax liability associated with those assumed revenues and expenses will be paid consistent with tax laws and regulations.[938] SCE further states that it "generally agrees with the facts"[939] asserted by TURN, acknowledges that SCE has incurred significant deductible tax costs over the past 10 years, that these costs "have mitigated SCE's authorized tax liability,"[940] and that future tax benefits "could limit Federal or State tax liabilities for the next few years."[941]

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[937] Ex. SCE-54 (Joint Comparison Exhibit), p. 236, TURN-98 updates TURN's calculation based on SCE most recent RO model run.

[938] Ex. SCE-18, p. 33.

[939] Ex. SCE-18, p. 33.

[940] Ex. SCE-18, p. 33.

[941] Ex. SCE-18, p. 33.

Notwithstanding SCE's agreement with TURN's statements and a recognition that from 2005-2018 SCE has included $2.8 billion more in revenue requirement than it has paid in federal income taxes, and that SCE has taken in $377 million more in revenue requirement than it has paid in California State income taxes, SCE asserts that these tax benefits were (and are) "outside of ratemaking."[942] The utility cites D.84-05-036, which found that "the Commission has consistently calculated income taxes for ratemaking purposes based on cost of service developed from adopted expenses which excludes the various disallowed expenses,"[943] and "because of a utility's affiliated or nonutility operations, a utility holding company's tax liability will be determined as a consolidated tax return. Thus, income taxes collected through authorized rates may not actually be paid." [944]

TURN believes the operative word in the D.84-05-036 Finding Of Facts cited by SCE is that taxes collected through authorized rates *may* not correspond to the cash taxes paid—not that such a mismatch is a regulatory goal. The context of the decision contemplates a consolidated parent company return rolling up a number of utility and/or non-utility operating companies who may have different tax positions, and whose parent entity may not pay liabilities taxes in the amount assumed for its utility affiliates individually.

It is doubtful that D.84-04-036 could have foreseen or intended SCE's circumstances where SCE, a utility holding company with a single fully-regulated utility operating subsidiary, consistently paid zero federal income taxes for nearly a decade while collecting billions of pre-

[942] Ex. SCE-18, V02, p. 34.

[943] Ex. SCE-18, V02, p. 34, citing D.84-05-036 p. 14.

[944] Ex. SCE-18, V02, p. 34, citing D.84-05-036 p. 18.

paid income taxes from ratepayers. In fact, in support of the "separate return" method[945] that such a string of tax losses is exceeding unlikely given the actions of the free capital market, D.84-04-036 stated, "in a free enterprise system the credo of capitalism is to maximize profit… it is inconceivable that the shareholders of the consolidated group are willing to maintain any operat[i]on in a losing position. Rather, one should expect that action will be taken to improve earnings so that past losses will be recovered."[946] In SCE's case, this operation in both a federal and state tax loss position has persisted since at least 2011.[947] D.84-04-036 goes on to observe "that if it can be shown that the consolidated group is in a permanent loss position, then the Commission should consider the impact that consolidated income taxes would have had on the effective tax rate to be used in calculating the adopted income taxes in setting rates."[948] Thus, while D.84-05-036 describes the general practices of the Commission in calculating taxes for ratemaking, it does not bar the Commission from taking a different approach and even suggests examples of situations where the Commission would be reasonable to deviate from its general practice, which TURN asserts would apply to the current situation.

SCE's tax losses have been so large and persistent that this is precisely a case where the Commission ought to depart from business as usual. SCE's primary reasoning for why the Commission ought to allow SCE shareholders to receive a windfall in the form of inflated working cash (for taxes SCE freely acknowledges it will not likely pay this GRC cycle) is

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[945] This is the practice of considering the utility's tax position separately from its parent or other affiliates under its parent for ratemaking which the Commission adopted.

[946] D.84-05-036 (1984 Cal. PUC Lexis 1325), p. 7.

[947] Ex. TURN-03, p. 39.

[948] D.84-05-036 (1984 Cal. PUC Lexis 1325), p. 7.

because the Commission has always allowed it before. In a continued refrain of "why stop now?" SCE is requesting that the Commission expressly "affirm the precepts established in OII 24 and deny TURN's inclusion of events outside this rate case."[949]

D.84-05-036 was not able to foresee and consider the unique situation that SCE has not and will likely not pay taxes for many years. The Commission can and should depart from the precedent set in D.84-05-036 for good reason, either as a response to unusual circumstances or as an ongoing change in practice. TURN recommends the Commission consider its past precedent in light of the magnitude of SCE's current GRC request and the billions of unpaid taxes already collected in SCE's revenue requirement over the past 10 years. TURN recommends that the Commission adopt a payment tax lag of 365 days for federal and state taxes as these better reflect the timing of actual tax payments. If the Commission chooses not follow TURNs recommendation, TURN urges the Commission to resist SCE's request to blindly reaffirm the Conclusions of Law reached in OII 24, which in the case of SCE, has resulted in a $2.8 billion windfall for shareholders over the past ten years.

37.3.2 Customer Deposits

Since SCE's 2003 GRC, the Commission has required SCE to apply customer deposits to offset rate base on the grounds that the deposit balances should be treated like a source of permanent working capital.[950] TURN recommends that the Commission continue this practice. TURN also recommends that the Commission continue to authorize SCE to use up to 10% of its customer deposits to promote its minority and community bank program.

949 Ex. SCE-18, p. 35.

950 Ex. TURN-03, p. 44.

In the 2018 and 2015 GRCs, SCE asked the Commission, as it did in its 2012 GRC, to reject this policy for a number of reasons, including arguments that the policy applies only to SCE, and deposits are actually debts rather than equity and otherwise fundamentally different than other working cash adjustments.[951] The Commission has repeatedly denied this request.

TURN urges the Commission to do so again in this GRC. TURN notes that SCE's customer deposits remain a permanent source of low-cost capital which compares favorably to SCE's weighted average cost of commercial paper as a source of short-term funds. The interest paid on customer deposits is de minimis and has ranged from 0.19%-1.84% annually over the period 2011-2018,[952] relative to SCE's weighted average interest rate for commercial paper of 3.23% and 2.24% for 2018 and 2019 respectively.[953]

SCE asserts the fact that customer deposits bear some de minimis interest obligates the Commission based on SP U-16 to exclude them from working capital. It does not, as the Commission has demonstrated in its prior decisions concerning the treatment of SCE's customer deposits regard since 2003. In D.04-07-044, SCE's 2004 GRC, the Commission explicitly addressed the applicability of SP U-16 to the treatment of customer deposits, stating that "as the Commission has previously held, U-16 is only a guide, and deviations are appropriate where circumstances warrant."[954]

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[951] Ex. TURN-03, p. 46, citing D.15-11-021 (SCE 2015 GRC), pp. 470-471, D.12-11-051 (SCE 2012 GRC), pp. 627-628.

[952] Ex. TURN-03 p. 48, footnote 130, citing DR TURN-SCE 009, CD Interest Rates Tab.

[953] Ex. TURN-03 p. 48, citing SCE 2019 10K, Note 5, p. 81.

[954] D.04-07-044, p. 253.

SCE asserts that "customer deposits are not like working cash adjustments such as vacation accruals. Accruals are deductions made to account for timing differences between when costs are incurred and when bills are paid. This delayed payout improves cash flow and makes working cash available."[955] But SCE's assertion is form over substance; its customer deposits have acted for SCE as permanent working capital because "SCE does not segregate the cash associated with customer deposits other than the 10% of customer deposits in SCE's minority and community bank program" from other short-term funds and sources of capital.[956]

SCE attempts to distinguish customer deposits from other cash sources by stating that "Customer Deposits are funds collected from customers for security against non-payment that will be returned" or used as a credit against bills in the case of non-payment.[957] TURN's overall point is that while individual customers may receive back or forfeit their customer deposits, on aggregate SCE has maintained a stable and often increasing pool of customer funds that provides it with a permanent layer of working capital as they have for the past two decades.[958] SCE itself concedes that customer deposits have resulted in a net positive working cash flow from 2012-2019.[959]

Additionally, SCE's customer deposits are a considerable source of funding, and have remained at a high, stable level. Since 2012, customer deposits have increased significantly from

[955] Ex. SCE-18, Vol 2, p. 41.

[956] Ex. TURN-67, DR TURN-SCE 114, Question 1.

[957] Ex. TURN-03, p. 48 citing SCE-07 V02 p. 42.

[958] Ex. TURN-03, p. 48 citing TURN DR 54, Q1a-b, Customer Deposits Summary Tab.

[959] Ex. TURN-67, DR TURN-SCE 114, Question 1.

a 13-month rolling average of $195 million to $290 million at the end of 2018.[960] In 2019, the balance continued to grow to $302 million.[961] SCE agrees that for the period from 2012-2019, the net annual cash received by SCE from customer deposits exceeded the cash from customer deposits refunded to customers.[962]

SCE argues that due to D.20-06-003, SCE can no longer request deposits from residential customers seeking new or reconnected service."[963] As a consequence, SCE's Customer Deposit balances have decreased since the beginning of 2020 and SCE is anticipating a decline in customer deposit balances during this GRC cycle.[964] Even so, SCE itself forecasts customer deposits to remain at a high level ranging from $261 million in 2021 to a low of $222 million in 2023.[965]

Finally, SCE asserts that the status of balancing account collections has no bearing on the treatment of customer deposits, and if it did then SCE is now showing a net under-collection as of its March 31, 2020, first quarter SCE filing. TURN disagrees with SCE's assertion. For utilities with ongoing under-collections, balancing accounts are a use of short-term funds to finance the revenue shortfall that will be made up in the future. For utilities with balancing accounts that are net over-collected on an ongoing basis, those over collections are a source of short-term funds, and they reduce the need for other sources of working capital. Over the period

[960] Ex. TURN-03, p. 48.

[961] Ex. TURN-67, DR TURN-SCE 114, Question 1.

[962] Ex. TURN-67, DR TURN-SCE 114, Question 1.

[963] Ex. TURN-67, DR TURN-SCE 114, Question 1.

[964] Ex. TURN-67, DR TURN-SCE 114, Question 1.

[965] Ex. TURN-67, DR TURN-SCE 114, Question 1.

of 2016-2019, SCE has had a net over-collection of $1.2 billion annually on average. SCE's balancing account overcollections have run on average at roughly 20% of 2018 recorded GRC base revenues. Removing customer deposits as an offset to working cash would tend to increase SCE's working cash revenue requirement, but SCE's over-collected balancing accounts already provide a significant source of stable, relatively low-cost short-term funds that do not need to be provided in rates. Yet, SCE asks the Commission to authorize a ratemaking treatment that pretends SCE would hold a zero customer deposits balance beginning in 2021. Not only would this ratemaking treatment be unrealistic, it would also unreasonably and unjustly increase costs to ratepayers.

TURN recommends that the Commission continue its treatment of customer deposits for SCE. Recognizing balances are expected to remain high but are declining through this GRC cycle, TURN recommends that the Commission adopt the lowest average forecast value, provided by SCE, of $221.888 million as the offset to rate base and reduction to working capital, rather than the base year average of $262.082 million.[966]

37.3.3 Other Working Capital Issues

37.3.3.1 Palo Verde Materials & Supplies

TURN recommended adjusting SCE's proposed materials and supplies inventory by relying on the 13-month average inventory shown in the APS budget.[967] By contrast, SCE's calculation was based on an average of 2016-2018 inventory subject to non-labor escalation. Using TURN's approach, the resulting inventory reduced from $35.663 million to $32.296

[966] Ex. SCE-54 (Joint Comparison Exhibit), p. 238, TURN-100.

[967] Ex. TURN-09, pages 13-14.

million (or 4.65% less in nominal dollars). In rebuttal testimony, SCE accepted TURN's recommendation to rely on APS budget data, which results in a 4.65% reduction, but makes an additional adjustment of $0.433 million to account for sales tax and unpaid inventory adjustments applied to all M&S inventory.[968] Since TURN accepts this additional adjustment, there are no remaining disputes with SCE on this issue.

37.3.3.2 Long-Term Incentives

38. DEPRECIATION AND DECOMMISSIONING

38.1 Overview

SCE seeks a $227 million increase to its authorized depreciation and decommissioning expense for test year 2021. Of this amount, $184 million is for depreciation of transmission and distribution assets, and represents the net impact of SCE's proposed $199 million increase for net salvage costs, offset slightly by the $15 mm decrease resulting from SCE's proposed service lives for those assets. The other material driver of SCE's requested increase is the proposal to initiate accrual of decommissioning costs for SCE's smaller hydroelectric generation assets; the utility proposes to start such collection at $30 million.[969]

The Commission should not adopt an increase of any amount to SCE's depreciation or decommissioning expenses in this GRC as a step toward mitigating the overall revenue requirement increase that is likely to result for test year 2021 and remain in place for each of the attrition years to follow. SCE is seeking to increase its GRC revenue requirement by $1.2 billion

[968] Ex. SCE-18v2, page 31.

[969] Ex. SCE-18, Vol. 3, p. 1, Table I-1.

based solely on a portion of its application here. Add in the impact of "Track 2" and of the vegetation management cost increases forewarned in SCE's update testimony, and the increase for 2021 climbs to approximately $1.7 billion. Under these circumstances, the Commission should seek out each and every opportunity to reduce the overall increase it will adopt without unduly impinging upon the funding found just and reasonable for programs and activities directly linked to SCE's provision of safe and reliable service. As the Commission has correctly recognized in the past, the funding for depreciation and decommissioning accruals present one such opportunity, as "depreciation does not affect [the utility's] ability to provide safe and reliable service."[970] In the 2018 GRC decision, the Commission noted that Standard Practice U-4 provides for regularly reviewed and updated depreciation showings, meaning future rate cases will serve as an opportunity to reconsider the need for revisions to accrual amounts, hopefully in the context of a far smaller proposed overall increase.[971] Denying SCE's requested increases would mean the utility continues collecting in rates approximately $1.6 billion of depreciation and decommissioning expense on an annual basis,[972] a figure that is understated in that it is based on plant balances as of the end of 2018. And the impact of the overall authorized revenue requirement increase from this proceeding would be partially reduced.

If the Commission decides to adopt any revision to existing depreciation or decommissioning rates or expenses, it should limit any increase to no more than is recommended in TURN's testimony and analysis presented in this brief, based on the evidentiary record

[970] D.00-02-046 (PG&E test year 1999 GRC), 2000 Cal. PUC LEXIS 239, *60.

[971] D.19-05-020 (SCE test year 2018 GRC), p. 319.

[972] Ex. SCE-18, Vol. 3, p. 1, Table I-1. SCE reports $1.83 billion as the "Total Proposed" figure under its recommended changes, and $227 million as the "Change from Authorized." $1.83 billion - $227 million = $1.6 billion.

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, and would increase the associated depreciation expense by $50 million on a stand-alone basis. By proposing more reasonable service lives for those same accounts, TURN's positions would result in a $59 million decrease as compared to the currently authorized service lives, and thereby offset the revenue requirement impact from the increased expense of its proposed net salvage figures. And TURN agrees with SCE that it is appropriate to begin accruing funds toward the decommissioning of the utility's smaller hydroelectric generation assets, but would have the collection start at $10 million per year rather than $30 million per year.[973] Each of these positions is fully explained and justified in TURN's prepared testimony on these topics.[974]

38.2 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 $199 million of increased annual depreciation accrual (based on 2018 year-end plant balances).[975] As noted above, TURN's primary recommendation is that the Commission adopt no change to existing net salvage rates as a step toward mitigating the revenue requirement impact of SCE's overall GRC request. In the alternative, TURN's depreciation analysis relied on the Commission's past

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[973] *Id.*

[974] Ex. TURN-08 (Garrett) addresses T&D net salvage and service life issues; Ex. TURN-09 (Marcus) covers decommissioning issues for generation facilities.

[975] Ex. SCE-07, Vol. 03, p. 2, Table I-1.

commitment to "gradualism" and recommended smaller changes to the currently authorized net salvage rates, resulting in a $50 million increase to the annual depreciation accrual.

38.2.1 Net salvage generally

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.[976]

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.[977]

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[976] Ex. TURN-08 (Garrett), pp. 39-40.

[977] *Id.*, p. 40.

38.2.2 TURN's Net Salvage Recommendation – The Commission Should Either Retain Currently Authorized Net Salvage Rates, Or Adopt 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.[978] 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.[979]

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."[980]

SCE's depreciation study proposed increased (that is, more negative) figures for the net salvage rates for eleven T&D accounts. There appears to be no mention in the utility's direct testimony of the concept of "gradualism" or any reference to the PG&E 2014 GRC decision. 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 described in the PG&E decision. That is, for each account for which SCE proposed a more

[978] D.14-08-032 (PG&E test year 2014 GRC), p. 597.

[979] *Id*. at 598.

[980] *Id*., at 602.

negative net salvage rate, TURN's adjustments limit the change to 25% of the utility's estimated increase. While TURN calculated the resulting net salvage rates would produce a $33 million increase in the annual depreciation expense when viewed in isolation,[981] SCE's calculations indicate a $50 million increase under TURN's recommendation.[982]

38.2.3 SCE Ignored the Concept of Gradualism In Its Depreciation Study, Then 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. After all, 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 concept under the circumstances, and instead retained the then-authorized rates as the more reasonable outcome.[983]

Here, SCE made no mention of "gradualism" in its depreciation study, and instead proposed increased net salvage rates that, if adopted, would result in an annual depreciation expense increase of $199 million when applied to 2018 plant balances (which would translate to a correspondingly larger increase if applied to authorized 2021 plant balances).[984]

[981] Ex. TURN-08 (Garrett), pp. 42-43.

[982] Ex. SCE-18, Vol. 3, p. 4, Table II-2.

[983] D.19-05-020 (SCE test year 2018 GRC), pp. 314 and 319.

[984] Ex. SCE-07, Vol. 03, p. 2, Table I-1.

38.2.3.1 SCE's Ongoing Claims Of Deficient Depreciation Rates Continue To Be Inadequately Supported.

A key element of SCE's arguments on these points is the utility's attempted revival of arguments the Commission has regularly and uniformly rejected in past GRC decisions. SCE assumes that the amounts it has recorded as cost of removal, as well as its and its past and present proposals for depreciation accruals and calculations of future costs of removal represent a sacrosanct truth that it should maintain 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, whether here or in prior GRCs, added to 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."[985] 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 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).[986] The

[985] *Id.*

[986] D.12-11-051 (SCE TY 2012 GRC), pp. 658-659.

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.[987]

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.[988]

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[987] *Id.*, pp. 671-672.

[988] D.15-11-021 (SCE TY 2015 GRC), pp. 394-395 (footnote citations omitted).

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 four to five times as much to remove the plant in service than it originally cost to install the plant.[989] 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.[990] In this way, SCE has substantial control over the amounts that it is reporting as "recorded" costs of 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.

38.2.3.2 SCE Falls Short with its Attempts To Illustrate The Inadequacy Of Past Depreciation Rates Found Just and Reasonable in Past GRCs.

In its rebuttal testimony, SCE describes the GRC outcomes since 2006 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 in nearly every

[989] Ex. SCE-18, Vol. 3, p. 31, Table III-9. The -469% and -508% figures reported as the 5-year and 10-year average for Account 364 (Distribution Poles), and the -438% and -474% averages for Account 369 (Services) indicate net salvage cost of 4.4 to 5.1 times the original plant cost. For Account 364, SCE's recorded figures for cost of removal have exceeded -700% in four of the past ten years. Gunn, SCE, 9 RT 958, l. 28 to 959, l. 26.

[990] Gunn, SCE, 9 RT 959, l. 28 to 960, l. 19.

GRC prior to this one.[991] In other words, SCE is criticizing the Commission for failing to authorize an increased overall depreciation rate in prior GRCs in which 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 lay the fault on the Commission's doorstep.

SCE's rebuttal testimony also includes an attempt to illustrate adoption of longer service lives along with "stagnated net salvage rates, leading to a growing and distressing gap between recorded costs and GRC-authorized costs for net salvage."[992] Again, the "recorded" costs are the SCE-produced figures, 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 2006 GRC through the 2018 GRC, the SCE-proposed average service lives increased by approximately 25% overall (from 39 years to 49 years), while its 10-year average "recorded" figures for net salvage rates increased by approximately **<u>250%</u>** (from -53% in 2006 to -133% in 2018). The GRC authorized net salvage rates increased by approximately 22% (from -51% to -62%) during that same period. TURN submits that SCE's table raises far more troubling questions about the pattern displayed by its "recorded" figures over this period than it does regarding the reasonableness of the Commission-adopted outcomes.

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[991] Ex. SCE-18, Vol. 3, pp. 6-7 and Figure II-1.

[992] *Id.*, p. 8 and Figure II-2.

SCE fares no better in its attempt to demonstrate that its overall depreciation rates should be increased when it compares its authorized and proposed rates with those of PG&E and SDG&E. Reliance on a combined T&D rate is misleading, as the three utilities have substantially different amounts of transmission plant subject to Commission jurisdiction, and that difference has a material impact on the overall rate calculated for each. SCE calculates its currently-authorized distribution-only depreciation rate as 3.71%, and a transmission-only rate of 2.53%.[993] For PG&E, the pending settlement in its test year 2020 GRC would yield a distribution-only depreciation rate of 3.90%, and a transmission-only rate of 2.67%. For SDG&E, the Commission's decision in its test year 2019 GRC provided a distribution-only rate of 3.83%, and a transmission-only rate of 3.14% (with the latter applicable to $4 million of plant; SCE has $5 billion of CPUC-jurisdictional transmission plant).[994] TURN submits that the differences between the rates for PG&E and SDG&E and the currently-authorized rates for SCE are not so large as to justify any increase here, particularly when SCE made no attempt to demonstrate that the different utilities would not be reasonably expected to have differences of this magnitude in their composite depreciation rates.

38.3 T&D Average Service Life

38.3.1 TURN's Analysis And Recommendations Are Firmly Based On SCE's Retirement Data and Produce Reasonable Curves and Lives.

TURN's depreciation recommendations propose service life adjustments to eight 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

993 Ex. TURN-73 (SCE Response to TURN-89, Questions 4 and 9), p. 2.

994 *Id.*, pp. 2-4.

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." In order to develop a complete curve that is consistent with the utility's recorded data, the survivor curve must be fitted and smoothed with a complete curve, a function that relies on "Iowa curves" that reflect known retirement patterns.[995] 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.[996]

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

[995] TURN's testimony included a more detailed explanation of how the Iowa curves are used in the actuarial analysis. Ex. TURN-08 (Garrett), Appendix C.

[996] Ex. TURN-08 (Garrett), pp. 9-11.

of the curve, and should be given less weight. The fitting process therefore focuses not only on the entire OLT curve, but also the portion that presented the most significant part of the curve for certain accounts.[997]

The following sections summarize TURN's showing on each of the eight accounts for which TURN proposes a life-curve that is different than SCE's proposal for the account.

38.3.1.1 Account 352 (Structures and Improvements)

The OLT curve derived from SCE's data for this account has adequate retirement history for Iowa curve analysis. TURN recommends a curve of L0.5-58, whereas SCE recommends L1-55. For this account, it is difficult to ascertain the better fit through a visual inspection analysis. Both curves have similar shapes, and both provide relatively close fits to the retirement data through the upper and middle portions of the OLT curve. Therefore, the mathematical curve fitting technique is particularly useful here. The sum-of-squared-differences (SSD) is 1.8815 for SCE's proposed curve, but 1.2079 for TURN's, indicating the L0.5-58 curve is a better mathematical fit with SCE's historical data. SCE's testimony referred to "unlikely recurring retirement activity" without further explanation or quantitative analysis of the impact of that activity on the utility's proposed service life.[998] The Commission should adopt the L0.5-58 curve as proposed by TURN.

38.3.1.2 Account 354 (Towers and Fixtures)

TURN recommends a curve of R5-69, whereas SCE recommends R5-65. The OLT curve for this account reflects relatively less retirement experience, as the curve does not drop

[997] *Id.*, pp. 11-12.

[998] Ex. TURN-08 (Garrett), pp. 13-16.

below 80% surviving in any year. Given these circumstances, the entirety of the OLT curve may not be suitable for visual and mathematical curve fitting. Therefore, TURN limited the analysis to only those data points associated with retirements that represent less than 1% of the beginning dollars exposed to retirement. The result is the selection of a curve that is a better mathematical fit than is SCE's (an SSD of 0.0222 for SCE's, and 0.0044 for TURN's).[999] The Commission should adopt the R5-69 curve as proposed by TURN.

38.3.1.3 Account 356 (Overhead Conductors and Devices)

TURN recommends a curve of R3-65, whereas SCE recommends R3-61. As with Account 354, discussed above, both Iowa curves provide relatively close fits to the OLT curve to a certain point, then statistically ignore the tail end of the OLT curve. And also as with Account 354, TURN's proposed curve achieves a better mathematical fit to the OLT curve (an SSD of 4.8243 for SCE's, and 2.9499 for TURN's). There is sufficient retirement history to provide reasonable estimates through use of conventional Iowa curve fitting analysis, making it inappropriate for SCE's depreciation study to defer to the opinions of SCE personnel.[1000] The Commission should adopt the R3-65 curve as proposed by TURN.

38.3.1.4 Account 361 (Distribution Structures and Improvements)

TURN recommends a curve of L0-58, whereas SCE recommends L0.5-55. The OLT curve for Account 361 is well-suited for conventional Iowa curve fitting techniques in that it is relatively smooth, contains adequate retirement history, and resembles a pattern typically observed in utility property retirement. Both recommended Iowa curves provide relatively close

[999] *Id.*, pp. 16-20.

[1000] Ex. TURN-08 (Garrett), pp. 20-23.

fits to the OLT curve through age interval 55, and correctly disregard data points occurring after the truncation point based on a 1% cutoff. TURN's proposed curve achieves a better mathematical fit to the OLT curve (an SSD of 0.0651 for SCE's, and 0.0501 for TURN's). While SCE cites input from its personnel suggesting no known reason why past retirement experience would not be expected to continue going forward, TURN's testimony explained that if this is true, it provides further basis for adopting the curve better supported by the historical data.[1001] The Commission should adopt the L0-58 curve as proposed by TURN.

38.3.1.5 Account 362 (Station Equipment)

TURN recommends a curve of L0-67, whereas SCE recommends S0.5-65. The OLT curve for Account 362 is relatively smooth and complete, and displays the retirement pattern of an L-shaped curve generally. SCE's selection of an S-shaped curve is puzzling, given the recorded data. The graph representing the recorded data and the TURN and SCE selections for the appropriate Iowa curve leave no doubt as to TURN's recommendation being the better visual fit. It is also a superior mathematical fit, as SCE's proposed curve results in an SSD of 0.3120, while TURN's results in an SSD of 0.0043. SCE's own historical data for this account clearly indicate an average service life of 67 years using an L-shaped curve, and the utility has presented inadequate reason for using a poor-fitting S-shaped curve for this account.[1002] The Commission should adopt the L0-67 curve as proposed by TURN.

[1001] *Id.*, pp. 23-27.

[1002] Ex. TURN-08 (Garrett), pp. 27-30.

38.3.1.6 Account 366 (Underground Conduit) - deferred

TURN recommends a curve of R2.5-64, whereas SCE recommends R1-59. For this account, the entirety of the OLT curve falls within the 1% truncation benchmark,[1003] resulting in a particularly shaped curve with no Iowa curve providing a near-perfect fit such as was the case for Account 362, discussed above. However, the R2.5-64 curve recommended by TURN provides a better visual fit, and the mathematical fitting process confirms this, as SCE's proposed curve results in an SSD of 0.2767, while TURN's results in an SSD of 0.0922. This is another account in which SCE proposes retention of the currently-authorized curve and resulting average service life based on its depreciation study having "deferred to the Company." Given that the OLT shows that at age 60, there are over 70% of the assets surviving in this account, an average life going forward in excess of 60 is strongly indicated.[1004] The Commission should adopt the R2.5-64 curve as proposed by TURN.

38.3.1.7 Account 369 (Services)

TURN recommends a curve of R1.5-60, whereas SCE recommends R1.5-55. Both of the recommended Iowa curves are shorter than the curve indicated by the OLT, as the historical data suggest an average life that is notably longer than those observed in the industry for this account. However, the OLT strongly indicates an average life going forward of longer than 55 years, and the 60-year life TURN proposes represents a good balance between current indications of average life, and the possibility that the average life may decline going forward. Indeed, the only

[1003] The "1% truncation benchmark" means that data points on the observed life table curve that are associated with dollars exposed to retirement that are less than 1% of the beginning dollars exposed to retirement are excluded from the statistical analysis and curve fitting process. TURN-08 (Garrett), p. 25 (in the discussion of Account 361).

[1004] Ex. TURN-08 (Garrett), pp. 30-33.

conclusion drawn from the utility's data is that the life should be longer than 55 years, and perhaps even longer than the 60 years proposed by TURN. TURN's recommended curve is also a better mathematical fit, as SCE's proposed curve results in an SSD of 0.5353, while TURN's results in an SSD of 0.3199.[1005] The Commission should adopt the R1.5-60 curve as proposed by TURN.

38.3.1.8 Account 370 (Meters)

TURN recommends a curve of R3-30, whereas SCE recommends R3-20. The OLT for this account does not have adequate retirement history for conventional Iowa curve fitting techniques. Going forward, the OLT will inevitably start to decline as retirement activity increases, and will likely form a pattern more resembling an Iowa curve. Of the assets in this account that have reached 30 years, 99% are still surviving, strongly suggesting a life of at least 30 years. TURN's recommended curve is also a better mathematical fit, as SCE's proposed curve results in an SSD of 8.5993, while TURN's results in an SSD of 1.2332.[1006] The Commission should adopt the R3-30 curve as proposed by TURN.

38.3.2 The Commission Should Find TURN's Recommendations Are Based On a More Straightforward Analysis With Data-Supported and Visually-Confirmed Curves Developed In An Understandable Manner.

TURN submits that SCE has presented a service life analysis that is highly likely to be largely if not entirely impenetrable to anyone lacking advanced course work in mathematics or statistics. The Commission needs to understand and, if necessary, be able to replicate the process that leads to the results that it may choose to include in its decisions. SCE's study is not

[1005] *Id.*, pp. 33-36.

[1006] Ex. TURN-08 (Garrett), pp. 36-39.

consistent with the Commissioners or their staff achieving the necessary level of understanding or ability to replicate.

SCE's depreciation study on issues associated with developing an average service life and life-curve combination for each account suffers some of the key flaws and shortcomings that the Commission found in SCE's study on net salvage issues in the test year 2018 GRC. As in the earlier GRC, SCE relied on the services of Foster Associates and, in particular, Dr. Ronald White. It was Dr. White's analysis of the utility's net salvage recommendations in the 2018 GRC that was the subject when the Commission stated, "We find, however, the study brings us no closer to resolving questions about the reliability of SCE's depreciation showing. Indeed, the study presents additional questions and assumptions <u>which are not readily verified or resolved</u>."[1007]

In its description of the analysis for the utility's transmission and distribution service life recommendations, SCE's study would leave even the most depreciation-savvy Commissioner or staff member perplexed. Consider, for example, SCE's witness's description of how he derived service life estimates for SCE plant and equipment. The description starts with a reference to analysis "using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios."[1008] As one would expect, it seems, "[t]he reason polynomials are limited to a third-degree term … is that some low modal Iowa curves exhibit two inflection points in a plot of the hazard function."[1009]

[1007] D.19-05-020, p. 314 [emphasis added].

[1008] Ex. SCE-07, Vol. 3, p. 68.

[1009] *Id.*, p. 70, fn. 80.

Later, the testimony describes the process as seeking "to estimate coefficients … of the polynomial from an estimate of hazard rates derived from a sampling of historical retirements recorded for a plant category." To estimate the coefficients in the SCE study, Dr. White used "orthogonal polynomials" pursuant to a procedure developed by Tchebysheff.[1010] In rebuttal testimony, SCE defended the superiority of its statistical techniques over those used by TURN's depreciation analyst by asserting

> In short, the statistical methods used in the 2019 SCE study maximize the informational content of the data and minimize the influence of extraneous events by analyzing the underlying forces of retirement at the level of independent hazard rates. [footnote 29] – Although some correlation can be found in the conditional proportion retired, the covariance between the hazard rates in two age intervals is asymptotically zero. This property has permitted the development of various methods of weighting that reflect serial independence of the disturbance term.[1011]

The Commission cannot permit the development of depreciation parameters to become so complicated or as to prevent a meaningful determination of the reasonableness of the process or its results.

SCE's approach here is, to TURN's knowledge, unlike any average service life analysis the Commission has previously accepted, either explicitly or by inference, in any prior decision. When TURN asked whether SCE's witness was aware of any other depreciation expert who relies on an approach to statistical service life studies similar to that used by Foster Associates, the utility's response did not identify a single example, instead claiming "Dr. White does not monitor how others may estimate service-life statistics."[1012] Instead, SCE pointed to material

[1010] *Id.*, p. 70.

[1011] Ex. SCE-18, Vol. 3, p. 21, including fn. 29.

[1012] Ex. TURN-68 (SCE Responses to TURN DR-078), Q/A 3.

from the appendix to NARUC's *Public Utility Depreciation Practices* as support for its approach. But the provided passage concluded with an affirmation of the role of visual inspection of the resulting curves in order to gauge "which smoothed survivor curve (life table) best fits the observed life table."[1013] As noted above, for a number of the accounts in dispute it was TURN's performance of the visual fit function that demonstrated the superior fit of TURN's proposed curves, as is well-illustrated in the graphs for each account that appear in TURN's testimony.

38.3.3 The Criticisms Raised in SCE's Rebuttal Lack Evidentiary or Analytical Support.

SCE's rebuttal testimony sought to undermine the quality of TURN's analysis and the reasonableness of the resulting curves by challenging the sum of squared differences (abbreviated as SSD in TURN's testimony, and SSQ in SCE's). Dr. White sponsored a table which purported to compare "SCE and TURN service lives, curves, and [SSQ] differences using T-Cuts reported by Mr. Garrett [TURN's analyst]." With one exception, the table accurately repeats the figures calculated and reported by Mr. Garrett with regard to TURN's proposed life and curve for each of the eight disputed accounts, as well as TURN's calculated SSQ figure.[1014] But for the values attributed to SCE, again with one exception, the listed curve shape is not the curve recommended by the utility,[1015] and for <u>none</u> of the accounts is the life value consistent with the utility's proposal. The rebuttal testimony and attachments contain nothing that would

[1013] *Id.*, excerpt from *Public Utility Depreciation Practices*, p. 247.

[1014] Ex.SCE-18, Vol. 3, p. 23, Table III-8. The SSQ for Account 352 is 1.2079 as calculated by Mr. Garrett, but is 0.1381 in SCE's table.

[1015] Again, the exception is for Account 352.

permit an interested party to cross-check or better understand the utility's calculation.[1016] SCE might be attempting to make the point that, had TURN's analysis sought to "derive service lives and curves that jointly minimize sum of squared differences," the resulting recommendations would be those attributed to SCE in Table III-8. But that badly misconstrues TURN's use of SSD in its analysis. As TURN's testimony explains, the retirement data for some accounts may not be suitable for reliance on mathematical curve fitting for the selection of the recommended curve, as the results might suggest an average life that is notably longer than what is observed in the industry for a given account.[1017] Had TURN merely sought to minimize the SSD results for a given account, the recommendations would have been for different curves and far longer average lives, as indicated by SCE's table indicating accounts with lives in excess of 100 years. Instead, TURN relied on SSD as one of several factors considered in selecting the recommended curve for a given account. TURN then also used a comparison of the SSD for the TURN-selected curve and for the SCE-selected curve to demonstrate that, for each of the eight accounts in question, TURN's selected curve achieves a better mathematical fit. And nothing in SCE's rebuttal counters that comparison or the reasonable conclusions to be drawn therefrom.

The Commission should also disregard SCE's attempt to characterize TURN's analysis as being of a lesser scope or relying on lesser quality data as compared to SCE's study.[1018] As TURN's testimony explains, Mr. Garrett obtained and reviewed all the data that was used to

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[1016] In contrast, the material used for the SSD calculations underlying TURN's recommendation were included in the attachments to the testimony. Ex. TURN-08, Exhibit DJG-6 through DJG-13.

[1017] *See, for example*, Ex. TURN-08 (Garrett), pp. 35-36 (discussing Account 369 – Services).

[1018] Ex. SCE-18, Vol. 3, pp. 21-22 and Table III-7.

conduct SCE's depreciation study.[1019] TURN in good faith assumed that SCE in fact provided all such data, which would cover everything in the "Database" and "Life Analysis" categories SCE has listed. And while it is true that TURN did not engage in field visits, there is nothing in SCE's depreciation study that indicates that such field visits provided critical information for the utility's development of its recommendations in the disputed accounts. Furthermore, SCE's study appears to have taken positions potentially contrary to the input received from SCE personnel. After all, the utility's direct testimony states, "The amount of weight given to the analysis of historical data will depend on the extent to which past retirement experience is considered descriptive of the future."[1020] And SCE's study indicates that for several accounts, SCE personnel provided confirmation that the past retirement experience is expected to be descriptive of the future, or at least that there is no reason to believe otherwise. But SCE's depreciation analysis treated such input as if it warrants maintaining the currently authorized curve,[1021] rather than recognizing that a different curve as suggested by the retirement data through 2018 reflects the likely retirement activity going forward. For the accounts addressed by TURN, SCE's determination to maintain the existing curve rather than rely on the historical data led to a shorter life and, as a result, higher depreciation rates, all else equal.

38.4 Small Hydro Decommissioning

The Commission should adopt TURN's proposed accrual amount for purposes of initiating accrual of decommissioning costs for small hydroelectric generation facilities. SCE

[1019] Ex. TURN-08 (Garrett), p. 8.

[1020] Ex. SCE-07, Vol. 03, p. 67.

[1021] *Id.*, Appendix A, pp. A-10 to A-11 (Account 352), A-25 to A-26 (Account 361), currently is not recovering in rates any amounts for the future decommissioning of its relatively small hydroelectric generation assets. As the utility describes it, this made sense until recently, given the renewable generation benefits that such small hydroelectric facilities provide, and their prior treatment as "potentially perpetual facilities."[1022] However, in light of changes that make the continued cost-effective operation such facilities less certain going forward, decommissioning may in some cases be the least-cost option for customers over the long-term.[1023]

There is no dispute among the parties about the appropriateness of permitting SCE to begin accruing funds for the potential future decommissioning of some of its small hydroelectric facilities. The difference in the parties' positions has to do with how to develop the appropriate amount for inclusion in rates at this time. SCE proposes to collect $29.6 million per year beginning in the 2021 test year,[1024] based on a calculation method that Public Advocates accurately described as "almost entirely and exclusively based on hypotheticals."[1025] Public Advocates proposes $6.8 million per year, as a result of focusing on the funding accrual on the two facilities with the greatest likelihood of decommissioning. TURN agrees with the staff's focus on the facilities that are either certain or highly likely to be decommissioned, but relied

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[1022] Ex. SCE-05, Vol. 1, p. 113; Ex. SCE-07, Vol. 3, p. 80.

[1023] Ex. SCE-05, Vol. 1, p. 115.

[1024] Ex. SCE-18, Vol. 3, Table IV-9, p. 30. In the Joint Comparison Exhibit (Ex. SCE-54), the utility's recommended funding level is listed as $27.4 million. It is not clear why this figure in the JCE is lower than the figure in Table IV-9 of SCE's rebuttal testimony, when the JCE figures for TURN and Cal Public Advocates match the figures calculated for those parties in Table IV-9.

[1025] Ex. PAO-16, p. 19.

upon more recent information to support an accrual of $10.1 million per year.[1026] TURN's proposed hydro decommissioning amount includes Borel, and the Agnew Lake and Rush Meadows plant within the Rush Creek facilities, the three plants with the highest probability of decommissioning. TURN's calculation includes setting hydro decommissioning costs in 2023 dollars rather than to the future year of retirement, consistent with the treatment of inflation in decommissioning estimates adopted in D.19-05-020. For the Borel plant, TURN also proposes to include the $31 million payment from the federal government to SCE as a reduction to rate base and amortize it as an offset to the Borel decommissioning expense over the expected remaining life of 14 years.[1027]

SCE estimated a probability of decommissioning for each plant, assigning each one of four scores ranging from 99% ("virtually certain" to be decommissioned) to 10% ("very unlikely, although the possibility cannot be ruled out").[1028] The Borel facility that has been rendered inoperable because the tunnel easement was condemned is the only plant to receive the 99% score. Two of the three dams in the Rush Creek system received the 90% score, consistent with the higher cost of needed seismic retrofitting, the fact that the two dams are no longer needed for generation, and SCE having modified the dams in a manner that results in reservoir levels that no longer meet FERC license conditions.[1029] There is no dispute among the parties

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[1026] The $10.1 million figure for TURN's recommendation matches the amount SCE calculated in its rebuttal testimony and that also appears in the Joint Comparison Exhibit, rather than the $9.761 million figure in Ex. TURN-09 (Marcus), p. 31. SCE's calculation reflects a more complete representation of escalation over a five-year period.

[1027] Ex. TURN-09 (Marcus), pp. 31-32. SCE has agreed to this offset. Ex. SCE-52 (Joint Comparison Exhibit), p. 252.

[1028] Ex. SCE-05, Vol. 1, pp. 115-116 and Table II-37.

[1029] *Id.*, p. 118-119.

about including forecasted decommissioning costs for these facilities in the development of a hydro decommissioning accrual figure.

TURN and Public Advocates both propose to exclude the facilities for which SCE has assigned a probability of either 50% or 10%. As Public Advocates explains, for the facilities with the 50% score, SCE has effectively omitted from its analysis the possibility of selling its small hydro assets.[1030] And for ten of the twelve small hydro facilities that received the 10% score, SCE's decommissioning cost estimates rely on data from a 2012 study.[1031] TURN does not suggest that it would never be appropriate to begin accruing amounts toward the potential decommissioning of at least some of these hydro assets with a 50% or below SCE-determined potential for decommissioning. But there needs to be further and more current analysis of both the likelihood of decommissioning and the expected costs before any amount should be included in rates based on that prospect. Therefore, the Commission should adopt TURN's and Public Advocates' position that the decommissioning accrual here should be calculated based solely on the small hydro assets for which SCE assigned a score of 90% ("very likely, but not completely certain") or higher.

In its rebuttal testimony, SCE warns of the possibility of "rate shock" in the future should the utility be forced to recover decommissioning costs in a "compressed period of time."[1032] The Commission should ignore this claim; if SCE makes a more complete and compelling showing in support of its small hydro decommissioning proposal in its next GRC, the period of time for collecting any decommissioning costs would be compressed or reduced by only a limited

[1030] Ex. PAO-16, p. 20.

[1031] *Id.*, p. 117, Table II-38, Note F.

[1032] Ex. SCE-18, Vol. 3, p. 31.

amount. Furthermore, the prospect of such a future adjustment resulting in "rate shock" has to be considered in the context of the "rate shock" embodied by SCE's proposal here. After all, the utility would saddle its customers with a $29.6 million increase in one fell swoop, given that the utility is collecting $0 in current rates toward the potential future decommissioning projects. Also for that reason, SCE should not be heard to argue that the recommendations of TURN and Public Advocates would represent "continuing to defer recovery" of such decommissioning costs.[1033] No party is proposing to maintain the *status quo*; each party is therefore seeking to achieve some amount of recovery where, today, there is none. SCE may prefer a more aggressive pace of accrual than what would be achieved under TURN's proposal, but that proposal represents an increased annual accrual of $10.1 million per year as compared to the currently authorized revenue requirement.

Even if the Commission were to determine that SCE had demonstrated that an annual accrual of $30 million may be justified, it should still adopt TURN's lower figure under the circumstances of this GRC. As noted at the outset of the brief, given the magnitude of the potential revenue requirement increase from SCE's billion-plus request, the Commission must seek out opportunities to reduce the impact of the adopted increase, including deferring increases that can reasonably be recovered, if necessary, in future GRC periods. Selecting a lower starting point to begin the movement toward developing a hydro decommissioning accrual would be consistent with such an approach, and mitigate in a small but important way the overall impact of the revenue requirement increase that will be adopted for the 2021 test year.

38.5 Decommissioning Escalation

[1033] *Id.*, p. 32.

The Commission should calculate generation decommissioning expense in 2023 dollars, consistent with the outcome adopted in SCE's test year 2018 GRC.

In SCE's test year 2018 GRC, the Commission rejected SCE's approach that escalated costs of decommissioning generation plant to the anticipated cost in the year of retirement some years or even decades into the future, then recover that escalated figure in equal amounts over the remaining service life of the plant. Instead, the Commission chose to escalate the decommissioning costs to 2020, and divide that figure by the remaining service life.[1034]

Here, SCE claims that the approach adopted in D.19-05-020 is not consistent with Standard Practice U-4, and proposes to instead rely on the approach that the Commission explicitly rejected in the 2018 GRC. Therefore, even though SCE proposes to use here the currently authorized decommissioning estimate for Mountainview, the Peakers, and its Photovoltaic generation plant (other than Perris, which is already decommissioned), its approach of reflecting inflation through the retirement year rather than through 2023 results in accrual increases.[1035] SCE has also escalated its decommissioning estimates for its small hydroelectric projects in the same manner.

TURN recommends that the Commission retain the method adopted in D.19-05-020, and calculate the generation decommissioning expense in 2023 dollars. Calculating decommissioning expense in nominal dollars from the future year of decommissioning, then using that figure as the basis for collections during this GRC cycle from 2021-2024, results in "collecting dollars now on a vastly inflated expense," the precise outcome the Commission

[1034] D.19-05-020, pp. 324-325.

[1035] Ex. SCE-07, Vol. 3, pp. 76-77 and 84-86.

sought to avoid in D.19-05-020.[1036] As TURN's testimony noted, for Mountainview, a dollar in the expected retirement year of 2040 is worth about 68 cents in 2021 dollars. Rather than requiring SCE's ratepayers in 2021-2024 to pay the same number of dollars that is expected to be collected from future ratepayers who will be paying in cheaper nominal dollars, the Commission should retain the just-adopted approach. Consistent with that approach, TURN's testimony calculated SCE's proposed decommissioning costs for Mountainview, the Peakers, and the Solar Photovoltaic projects in 2023 dollars. TURN's small hydro decommissioning recommendations are also stated in 2023 dollars.[1037]

TURN's testimony also included an alternative method for including escalation in SCE's decommissioning estimates, should the Commission choose not to follow the approach adopted in D.19-05-020. SCE uses a specific and inappropriate Handy-Whitman escalation rate for purposes of escalating its decommissioning estimates from past studies to current dollars.[1038] TURN explained that the Handy-Whitman index is not a good fit for purposes of escalating plant demolition and removal costs, because it is developed as a construction cost index for gas turbine peaker plants. In addition, it includes escalation of the cost of materials, a factor not present for decommissioning activities.[1039] The Handy-Whitman index increases were much higher than general inflation, with compound growth rates in the 5.0% to 5.6% range during the periods in question, driven by even larger increases in cost for gas turbine plant during those periods.[1040]

[1036] D.19-05-020, p. 325.

[1037] Ex. TURN-09 (Marcus), pp. 34-35.

[1038] *Id.*, p. 35.

[1039] *Id.*

[1040] *Id.*, pp. 35-36.

The mismatch of an index based solely on gas turbine peakers to the costs of decommissioning solar production plant is particularly pronounced.[1041]

Under TURN's primary proposal of maintaining the approach adopted in D.19-05-020 and calculating the decommissioning cost estimates in 2023 dollars, there is less need to make an adjustment to correct for the inappropriate escalation rates from 2003-2018. But if the Commission instead adopts SCE's proposal for future inflation here, TURN recommends using a 4% compound rate of increase for the 2003-2018 period, reflecting the 3.34% reported figure adjusted judgmentally to 4% to assure conservatism in light of potential increases in non-labor construction costs and potential differences in percentage wage increases.[1042] Use of a 4% rate for the 2003-2018 escalation yields a decommissioning expense reduction of $342,000 as applied to Mountainview, the Peakers, and the Solar Photovoltaic projects.[1043] The reduction to hydro decommissioning expense would be approximately $2.7 million.[1044]

38.6 Perris Decommissioning

The Perris solar project (10.2 MW (DC)) was installed by SCE in 2012 pursuant to the Solar Photovoltaic Program (SPVP) authorized in D.09-06-049. It represents the largest single project in the SPVP in SCE's portfolio of 91 MW of utility-owned rooftop solar.[1045] Although SCE negotiated a 20-year lease for the Perris solar project rooftop site, the facility was retired

[1041] *Id.*, p. 36.

[1042] *Id.*

[1043] *Id.*, p. 34, Table 27.

[1044] Compare TURN estimate of $11.9 million before the amortization of $31 million of federal payments (from comparison exhibit workpapers) to SCE estimate of $14.6 million for Borel and Rush Creek (Agnew, Rush M.) only. (SCE-7 Vol. 3, p. 82)

[1045] D.13-05-033 (SCE-owned projects comprise a total of 91 MW).

and decommissioned after only 7 years of operations.[1046] No other projects deployed by SCE under the SPVP program have been subject to premature decommissioning.[1047]

SCE requests full recovery of both decommissioning costs associated with the Perris solar facility and the remaining capital costs with a full rate of return for shareholders. TURN offers three recommendations. First, the Commission should limit the recovery of decommissioning costs to those incurred to date. Second, TURN urges the Commission to deny mass property treatment to Perris and authorize recovery of the remaining net plant over six years with no return on equity or debt.[1048] Third, SCE should be directed to pursue any legitimate damage claims against the facility owner with 95% of the proceeds credited to ratepayers.[1049]

38.6.1 The Commission Should Not Permit Recovery Of Decommissioning Costs Beyond Those Incurred To Date

The Joint Comparison exhibit provides a summary of positions based on a forecast decommissioning cost of $6.5 million.[1050] However, this figure appears to be well in excess of the expected cost of decommissioning based on recorded figures, data responses and testimony provided during evidentiary hearings. At the end of June 2020, project decommissioning was complete and SCE had incurred $3.81 million in decommissioning costs.[1051] Although "physical

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[1046] 5 RT 698 (SCE/Rankin)

[1047] 5 RT 719: 6-10 (SCE/Rankin)

[1048] Ex. TURN-09, page 37.

[1049] Ex. TURN-09, page 37.

[1050] Ex. SCE-54, page 248; Ex. SCE-18v3, page 40, Table VI-12.

[1051] Ex. TURN-046, SCE response to TURN Data Request #91, Q14.

decommissioning" was complete as of April 2020, SCE asserts that recorded costs are "not final" because of "building restoration issues" subject to resolution with the facility owner.[1052]

During evidentiary hearings, SCE witness Rankin clarified that "building restoration" refers to "hardware on and near the side of the building" that <u>may</u> have to be removed.[1053] As of June 26, 2020, SCE had not received any written confirmation from the facility owner regarding "a need for additional restoration work on the roof" that would allow for an estimate of remaining costs.[1054] When asked to explain this statement, SCE witness Rankin could not identify any additional work that would be required by the landlord.[1055] Similarly, SCE witness Gunn explained that, with respect to remaining costs, "there's a little bit of work that it's unclear whether or not we'll have to perform."[1056]

Given these facts provided just prior to, and during, evidentiary hearings, and in the absence of any clearly supported estimate of remaining costs, the Commission should decline to authorize the recovery of any decommissioning costs in excess of the $3.81 million recorded as of June 2020. This limit on cost recovery should be enforced regardless of whether the Commission adopts the other ratemaking recommendations proposed by TURN. Even if the Commission decides to authorize additional costs, the $6.5 million figure provided in SCE's application should not be used because there is no basis to find it reasonable.

[1052] Ex. TURN-046, SCE response to TURN Data Request #75, Q3.

[1053] 5 RT 712: 9-20 (SCE/Rankin)

[1054] Ex. TURN-046, SCE response to TURN Data Request #91, Q14.

[1055] 5 RT 713: 11-13 (SCE/Rankin)

[1056] 9 RT 988: 21-23 (SCE/Gunn)

38.6.2 The Terms Of SCE's Lease With The Facility Owner Were Not Reasonable

SCE's decision to execute a 20-year lease with the owner of the facility hosting the Perris solar project was questionable in light of information that it knew before making the commitment. As explained in TURN's direct testimony, an inspection report commissioned by SCE indicated a remaining 15-16 year service life for the roof, less than the contemplated 20-year duration of the lease agreement.[1057] In rebuttal testimony, SCE argues that repairs undertaken prior to the project installation, combined with expected UV protection provided by the project "extended the expected service life to 15-20 years at the time SCE committed to build the facility."[1058] Even under SCE's revised projections, the remaining service life of the roof was barely adequate to ensure the project could operate for the intended period of 20 years.

Despite this knowledge, SCE proceeded to execute a 20-year lease agreement that gave the facility owner the absolute right to require removal of the project at SCE's sole expense if repairs or replacement to the roof were desired by the landlord. SCE witness Rankin agreed that the lease allowed the landlord to exercise this option without satisfying any criteria or proving to SCE that there is a sufficient basis for roof replacement.[1059] Although the Commission authorized SCE to build rooftop solar projects pursuant to D.09-06-040, the lease agreement associated with the Perris project was never reviewed or approved.[1060] This case represents the first time that the arrangement is subject to Commission scrutiny.

[1057] Ex. TURN-09, pages 37-38.

[1058] Ex. SCE-18v3, page 43, lines 1-2.

[1059] 5 RT 701: 13-18 (SCE/Rankin)

[1060] Ex. TURN-046, SCE response to TURN Data Request #62, Q6.

SCE asserts that its installation and ownership of the Perris project did not cause, or contribute to, the need for roof replacement.[1061] Moreover, SCE "did not agree" with the landlord that a roof replacement was necessary.[1062] Although SCE "did communicate to the building owner that we didn't think either our system caused it or a reroof was necessary", the landlord proceeded to require removal of the entire solar project.[1063] Because the lease obligated SCE to remove the entire project at its own expense, there were no specific remedies available to protect ratepayer interests.[1064] In response to a data request from SCE, TURN witness Marcus expressed concerns about the reasonableness of this type of lease arrangement:[1065]

> Such a provision may be unreasonable if it assigns all early removal storage and re-installation costs to the lessee in the event that the need for complete roof replacement is not attributable to damage caused by the lessee or the installed project fixtures. Additionally, it may not be reasonable for such a provision to provide the lessor with the right to pursue total replacement of the roof when discrete repairs that do not require the removal of all installed project fixtures would be sufficient. An unreasonable resolution of these specific issues can be found in the lease between SCE and Falcon Perris CA (see Ex. TURN-09, Attach 2C).

In negotiating and executing the lease, there is no evidence that SCE adequately considered the incremental costs of premature removal storage and reinstallation of the entire project. There is also no evidence that SCE adequately protected its interests in the event that the lessor opted for complete roof replacement when discrete repairs would be sufficient. Moreover, the roofing report provided by Edison casts significant doubt whether the host roof was likely to avoid the need for repairs or replacement over the project life.

[1061] 5 RT 700: 1-17 (SCE/Rankin)

[1062] 5 RT 709: 2-5 (SCE/Rankin)

[1063] 5 RT 702: 21-28 (SCE/Rankin)

[1064] 5 RT 704: 1-6 (SCE/Rankin)

[1065] Ex. SCE-114, TURN response to SCE Data Request 16-WM, Q4.

Concerns over the reasonableness of this lease provision are highlighted by the heated exchanges triggered by the facility owner's demand that the Perris project be removed for roof replacement. While SCE witness Rankin testified that SCE agreed to move "quite expeditiously" to remove the solar installation, the events following the landlord's original notification of its intent to replace the roof were marked by significant disagreements between SCE and the facility owner.[1066] The confidential correspondence shows that SCE appeared surprised by the request and struggled to accept the consequences of the unreasonable and unfavorable lease terms it had negotiated.[1067] In originally negotiating the lease, SCE failed to secure any protections against an obligation to comply with a questionable request to remove a large solar installation on very short notice and was ultimately forced to do so at its expense. The absence of any opportunity to challenge the need for roof replacement, and the unilateral right of the landlord to order the removal of the project with little notice, suggests that the lease agreement was unreasonable from the perspective of SCE and its ratepayers. As explained by TURN witness Marcus, in light of the questionable decision such a lease, "assigning the total cost of this mistake to customers is not warranted."[1068]

38.6.3 Perris Should Be Removed From Mass Property Accounting Treatment

TURN witness Marcus proposed removing Perris from mass property accounting treatment and retaining the existing depreciation treatment for the other 24 rooftop solar projects

[1066] 5 RT 710: 2-9 (SCE/Rankin). In particular, TURN refers to the letter from SCE outside counsel contained in Ex. TURN-09-Attach2-C, pages 82-83.

[1067] The entire chain of communications can be found in Ex. TURN-09-Attach2-C.

[1068] Ex. TURN-09, page 38.

owned by SCE.[1069] The remaining projects would continue to be treated as mass property. This outcome would allow the Commission to apply traditional abandoned plant treatment to Perris consistent with decades of precedents denying utilities the ability to earn a return on facilities that are no longer used and useful.

TURN offers several rationales for removing Perris from the group accounting treatment proposed by SCE. First, Perris was a large, stand-alone solar project that is amenable to unit accounting because the costs are distinct and easily trackable. At 10.2 MW, Perris is the single largest solar project owned by SCE and comprises 11% of generating capacity in a 25-project utility-owned solar portfolio. This fact makes it different than large numbers of smaller and geographically disbursed items typically subject to mass property treatment. Second, the early retirement of Perris will not lead to its replacement with another similar item of property. Due to modifications to the SPVP adopted in D.12-02-035 and D.13-05-033, SCE ceased any further efforts to develop utility-owned projects under the program. As a result, any existing facility that is retired will not be replaced by a new utility-owned solar project.[1070] Third, removing Perris from group accounting will allow the Commission to protect ratepayers from paying a full rate of return for more than a decade on a project that was removed from service in 2019. Moreover, there is little reason for the Commission to assume that the remaining projects in the group accounting portfolio will operate for longer than the term of their current leases.

Although TURN recognizes that SCE previously sought group accounting for Perris costs, the Commission should not take this fact as determinative of the outcome in this

[1069] 11 RT 1143: 5-8 (TURN/Marcus)

[1070] 9 RT 988-989 (SCE/Gunn)("I'm not aware of any plans to replace the retired capacity.")

proceeding. SCE's application of group accounting to Perris was never challenged by any party and therefore was not litigated in a prior GRC.[1071] The lack of a prior challenge is not surprising because Perris is the first facility in the portfolio to retire prematurely. The premature retirement of the single largest asset in the portfolio justifies a review of SCE's proposed treatment. Since the Commission has never actively considered the reasonableness of this approach, it is not constrained by precedent. Moreover, the Commission previously approved recategorizations of SCE expenditure to modify the applicable accounting treatment so long as the changes "are not an assault on the integrity of the future test year ratemaking process."[1072]

Finally, TURN notes that the treatment proposed by SCE is not required under Standard Practice U-4. When asked about the applicability of Standard Practice U-4 to the Perris facility, SCE witness Gunn agreed that "there's some judgment that goes into determining whether or not the depreciation rate should be authorized as a group or as an individual unit."[1073] Mr. Gunn noted that group depreciation is appropriate where a large number ("millions") of smaller components deployed throughout an entire service territory, that unit depreciation is more appropriate for an individual facility with a "terminal date" assumed for retirement, and pointed out that the Perris facility falls "somewhere in between those two things."[1074] TURN asserts that the Perris facility, as a stand-alone power plant with an expected service life, should be treated as an individual unit for purposes of depreciation.

[1071] 9 RT 988: 8-15 (SCE/Gunn)

[1072] D.19-05-020, page 355.

[1073] 5 RT 991-992 (SCE/Gunn)

[1074] 5 RT 990-991 (SCE/Gunn)

38.6.4 Under Established Ratemaking Treatment Of Abandoned Plant, Unrecovered Capital Should Not Earn A Rate Of Return

SCE seeks to realize a full return on the unrecovered capital investment in Perris despite the fact that the project is no longer "used and useful" and was retired 13 years early. 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.

TURN relies on a number of key 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.[1075]

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.[1076] The Commission denied any return on capital at several retired LNG facilities in the same rate case.[1077]

[1075] D.85-08-046, page 22.

[1076] D.85-12-108, 1985 Cal. PUC LEXIS 1112, *57.

[1077] D.85-12-108, 1985 Cal. PUC LEXIS 1112, *64.

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.[1078]

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."[1079]

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.[1080] 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."[1081] The Commission need not

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[1078] D.92-12-057, 1992 Cal. PUC LEXIS 971, *83, *84

[1079] D.12-11-051, pages 652-653

[1080] D.92-12-057, 1992 Cal. PUC LEXIS 971, *83, *84

[1081] D.85-08-046, page 22.

reach any conclusion with respect to prudence in order 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 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.[1082] Since this outcome was included in a Settlement, and involved an associated commitment to retire the facility, it cannot be considered precedential. Since the issuance of this Decision, the Commission has expressly declined to consider D.92-08-036 as a relevant precedent.[1083] 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."[1084]

In the case of SCE's legacy electromechanical meter retired prematurely due to the

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[1082] D.92-08-036.

[1083] 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.")

[1084] D.11-09-017, page 6; D.10-06-031.

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.[1085] 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 and useful should be excluded from rate base (and therefore excluded from earning a rate of return)."[1086]

These precedents demonstrate that the basic presumption for any prematurely retired facility is that 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".

38.6.5 SCE Should Be Directed To Pursue Any Legitimate Damage Claims Against The Facility Owner And Credit 95% Of The Proceeds To Customers

TURN's testimony notes the presence of unresolved issues that suggest an opportunity to recover some of the lost value associated with the premature retirement of Perris from the facility owner.[1087] Confidential correspondence between SCE and the facility owner supports this

[1085] D.12-11-051, pages 649-650.
[1086] D.11-05-018, page 55.
[1087] Ex. TURN-09, page 39.

view.[1088] In the event that any legitimate claims against the facility owner arise, SCE should aggressively pursue them and credit 95% of any proceeds to ratepayers.[1089] In rebuttal testimony, SCE agreed to return 100% of all proceeds to customers that may be recovered in the event any claims are successfully pursued.[1090]

38.7 Palo Verde Interim Retirements

TURN's prepared testimony recommends reducing SCE's forecast of Palo Verde interim retirements by $1,767,000 (end of 2018) or 0.089% of gross plant.[1091] TURN's recommendation is based on a 7-year average (2012-2018) that excludes zero values in 2009-2010 and an unusually high value in 2011 for a major capital project (reactor head replacements) that is unlikely to repeat in the near future.[1092] This approach is more reasonable than SCE's reliance on a 10-year average especially in light of the fact that Palo Verde recorded relatively low levels of retirement post-2011.[1093]

SCE's rebuttal laments TURN's proposal to rely on a 7-year average and exclude 2011 data primarily because it yields a number that is lower than SCE's own proposal. SCE urges the Commission to adopt the higher values proposed by SCE, in part, because of the potential for APS to replace evaporative pond liners at some point in the next 10 years.[1094] The fact that such

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1088 Ex. TURN-09-Attach2-C, pages 82-83.

1089 Ex. TURN-09, page 39.

1090 Ex. SCE-18v3, page 47: 1-3.

1091 Ex. TURN-09, page 28.

1092 Ex. TURN-09, pages 29-30.

1093 Ex. TURN-09, page 29; Ex. TURN-09-Atch1, Attachment 6.

1094 Ex. SCE-18v3, page 49: 16-21.

an investment may occur within the next 10 years is not a sufficient reason to reject TURN's approach. Since SCE's capital cost forecast has not identified costs for pond liner replacements (or other major projects that will produce a spike in interim retirements) during the current GRC cycle, the Commission should be able to engage in a timely consideration of the potential impact of longer-term capital projects on interim retirements beyond the current GRC cycle in the next GRC.

38.8 Fuel Cell Generation

TURN's prepared testimony recommends two changes to the forecasted decommissioning cost of the two fuel cell installations located at the University of California at Santa Barbara and California State University at San Bernardino. SCE requested $3 million to decommission these plants ($1 million/year). TURN recommends $1.36 million (or $0.453 million/year).[1095] TURN's recommendation is based on two adjustments to SCE's request.

First, TURN recommends using a 15% contingency for these decommissioning cost estimates rather than the 25% proposed by SCE. The use of a 15% contingency rate is comparable to the approach used by Pacific Gas and Electric Company for fossil decommissioning.[1096] The use of 15% contingency is also consistent with the Commission's adoption of TURN's recommendation to use this factor for large scale facilities by SDG&E.[1097] Given the relative simplicity of fuel cell decommissioning relative to a large fossil generator or

[1095] Ex. TURN-09-E, pages 39-41.

[1096] Ex. TURN-09, page 39, *citing* PG&E 2014 GRC, Exhibit PG&E-6, workpaper 4-132.

[1097] D.19-09-051 (Sempra GRC), page 627 ("We also find SDG&E's use of a 20 percent contingency is not supported by sufficient justification and by comparison find TURN's recommendation of a 15 percent contingency more reasonable.")

other large-scale facility, the use of a 15% contingency factor for a small fuel cell installation is appropriate. The application of a 15% contingency factor reduces the forecast decommissioning cost from $3.0 million to $2.72 million.[1098]

Second, TURN recommends reducing the amounts collected for decommissioning by 50% to $1.36 million because SCE has not demonstrated that these facilities are likely to be decommissioned in the near future.[1099] SCE's direct testimony notes that, despite the longstanding expectation that the ownership of these fuel cell projects would be transferred to the site hosts after 10 years of operations, SCE retains the obligation to remove the projects at the request of the site owners when the existing leases end in 2022 and 2023.[1100] To date, SCE has not received any communications from the two site hosts regarding their intentions with respect to retaining the fuel cells.[1101]

In rebuttal testimony, SCE affirms the absence of any formal communications with the site hosts but suggests "other considerations lead SCE to believe" that decommissioning will occur at the end of the current lease terms.[1102] The factors referenced by SCE constitute speculation, are not persuasive, and should be given little weight by the Commission. In the case of CSU San Bernadino, SCE suggests that although the University is interested in using onsite generation to provide resiliency during grid outages, the option of retaining the fuel cell is

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[1098] Ex. TURN-09-E, page 40.

[1099] Ex. TURN-09-E, page 41.

[1100] Ex. SCE-7, Vol. 3, p. 87.

[1101] Ex. TURN-09, page 40, *citing* SCE response to TURN Data Request 62, Q18.

[1102] Ex. SCE-18v3, page 51.

unlikely to be pursued due to the need for significant investments to island the unit and provide additional storage.[1103] SCE provides no evidence of the costs, does not examine whether CSUSB could use the fuel cell to serve part (but not all) of its onsite needs, and fails to consider the alternative expense that CSUSB would incur to achieve resiliency without the fuel cell. Absent any formal communication from the two site hosts, the Commission should not assume that both entities will decline the option to assume ownership of a low-emission generating resource that can provide significant value during a period of increasingly frequent outages and a growing need for system and local capacity.

Given this uncertainty, it is premature to force SCE ratepayers to contribute the full cost of decommissioning. As explained by TURN witness Marcus, "customers would rather keep the money in their pockets until it is clear that the cost is actually needed for the stated purpose." To address this uncertainty, TURN recommends limiting collections to 50% of the requested amount ($1.36 million total or $0.453 million/year).

38.9 General & Intangible Plant

38.10 Other Issues

TURN also recommends that SCE conduct a decommissioning study for Mountainview, a representative peaker, and a representative solar plant for its next GRC. TURN explained that the use of questionable escalation rates for long periods of time, and the actual cost of Perris solar decommissioning being lower than the utility's earlier escalated estimate, suggest that fresh

[1103] Ex. SCE-18v3, page 51.

decommissioning studies should be done after the passage of 18, 14, and 10 years (to 2021), respectively, since the most recent studies.[1104]

SCE's rebuttal testimony noted TURN's recommendation for "additional decommissioning studies," and agreed "to revise the decommissioning estimates of the following plants in the next GRC."[1105] To the extent SCE's reference to "revising" the estimates is intended to mean "conduct a new decommissioning study" for the plants TURN had identified in its testimony, TURN appreciates SCE's willingness to agree to doing new studies, and urges the Commission to memorialize in the decision here that these new studies are to be conducted. If SCE intended its statement to mean something other than conducting a new decommissioning study as described in TURN's testimony, the Commission should adopt TURN's recommendation without whatever modification SCE might have intended to make.

39. TAXES

39.1 Overview

39.2 Income Taxes

39.3 Payroll Taxes

39.4 Property Taxes

39.5 Other Tax Issues

40. OTHER RESULTS OF OPERATIONS ISSUES

40.1 Development of the CPUC-Jurisdictional Revenue Requirement

40.2 Present Rate Revenue

40.3 Cost Escalation

[1104] Ex. TURN-09 (Marcus), p. 41.

[1105] Ex. SCE-18, Vol. 3, p. 38.

40.4 Overhead Allocation

41. POST TEST YEAR RATEMAKING

41.1 SCE's Proposal

SCE proposes a two-part post-test year ("PTY") ratemaking mechanism, also referred to as an "attrition" mechanism, that determines attrition-year revenue requirement based on fixed levels of escalation for test-year expenses and plant additions.[1106] SCE would take the same series of escalation factors that it proposes to use in developing the test-year expense levels and use them in developing attrition year expense levels.[1107] SCE would develop the capital revenue requirement (associated depreciation, return, and taxes) based on budgeted levels of attrition-year plant additions.[1108] In this proceeding, SCE splits out the capital revenue requirement associated with wildfire expenditures in order to demonstrate compliance with Assembly Bill ("AB") 1054.[1109] Under SCE's proposal, the attrition increase relative to Test Year ("TY") 2021 would amount to 5.6% and 6.4% for Attrition Year ("AY") 2022 and AY 2023, respectively.[1110]

41.2 TURN's Proposal

[1106] Ex. SCE-07V4A, p. 26.

[1107] *Id.*, p. 28.

[1108] *Id.*, p. 31.

[1109] AB 1054 Section 18(e) states: "The commission shall not allow a large electrical corporation to include in its equity rate base its share, as determined pursuant to the Wildfire Fund allocation metric specified in Section 3280, of the first five billion dollars ($5,000,000,000) expended in aggregate by large electrical corporations on fire risk mitigation capital expenditures included in the electrical corporations' approved wildfire mitigation plans." Section 3280(n) specifies that SCE is responsible for 31.5 percent of the $5 billion or $1.575 billion.

[1110] Ex. TURN-07, p. 21.

TURN recommends that the Commission adopt a two-part PTYR mechanism that escalates O&M expenses using a broad index[1111] and determines capital-related costs separately for wildfire expenditures versus non-wildfire expenditures.[1112] TURN recommends that SCE's wildfire mitigation capital additions should be based on a specific capital budget adopted for the test year and each attrition year while non-wildfire related capital additions should be based on the adopted non-wildfire related capital additions for the test year with zero escalation in each of the attrition years.[1113] Under TURN's proposal, the attrition increase would amount to 4.9% and 4.8%, respectively, for AY 2022 and AY 2023 in its primary proposal and 5.1% and 4.9%, respectively, for AY 2022 and AY 2023 in its secondary proposal.[1114]

41.3 SCE Continues to Gloss Over the Commission's Policy Regarding Attrition.

While the Commission established the attrition mechanism to provide the utilities some opportunity between GRCs to maintain their financial health, the Commission has made it abundantly clear that the utilities do not have a "right" to an attrition adjustment.[1115] Furthermore, since the Commission has found a variety of attrition mechanisms to be reasonable over the last several decades, the Commission should disregard SCE's insistence that only one attrition mechanism is proper. Finally, in making its determination regarding the appropriate attrition adjustment, the Commission has recognized the importance of balancing the need to

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[1111] Regarding the broad index for escalating O&M expenses, TURN proposes using the CPI-U in its primary proposal and CPI-U plus 50 basis points as its alternative proposal. Ex. TURN-07, p. 16-17.

[1112] Ex. TURN-07, p. 18.

[1113] *Id.*, p. 20.

[1114] *Id.*, p. 21.

[1115] *See, e.g.,* D.17-05-013, pp. 132-133; D.00-02-046, p. 471, citing to D.96-01-011, p. 374.

maintain utility financial health against the need to minimize rate increases for utility customers, particularly during adverse economic conditions.[1116]

And conditions are indeed adverse for ratepayers. Today, no one knows the full extent and duration of COVID-19's impact. But, of course, there are forecasts. For example, UCLA Anderson Forecast's June 2020 Report, "The UCLA Anderson Forecast for the Nation and California," projects a slow recovery for the United States:

> To call this crisis a recession is a misnomer. We are forecasting a 42% annual rate of decline in real GDP for the current quarter followed by a "Nike swoosh" recovery that won't return the level of output to prior fourth quarter of 2019 peak until early 2023. …
>
> Similarly, employment won't recover until well past 2022 and the unemployment rate will be around 10% in this year's fourth quarter and will still be above 6% in the fourth quarter of 2022. … Thus for too many workers the recession will linger on well past the official end date of the depression.[1117]

Importantly, UCLA Anderson Forecast explains that this forecast assumes "a start-stop return to normalcy with vaccines available in early 2021 and, most importantly, most of the nation's public schools reopen in the fall."[1118] Unfortunately, the assumption about schools is proving to be overly optimistic as most schools nation-wide have not re-opened. It is too early to know when vaccines will be widely available.

UCLA Anderson Forecast projects that the California recovery will look very much like the U.S. recovery, with faster- and slower-to-recover economic sectors. However, they heavily caveat this forecast on the "strong assumption" that the pandemic abates "this summer and to the extent it returns in 2021 and 2022, it does not generate another shutdown nor a dramatic decrease

[1116] D.09-03-025, p. 306.

[1117] Ex. TURN-24, UCLA Anderson Forecast, June 2020, p. Nation-13.

[1118] Ex. TURN-24, UCLA Anderson Forecast, June 2020, p. Nation-13.

in consumption as happened in 2020."[1119] Unfortunately, once again, we have not seen the COVID-19 abatement that many hoped for this summer. Instead, we saw widespread outbreaks throughout California, notably in much of SCE's service territory.

Suffice it to say, we are living in a time of rapidly changing public health and economic conditions, where the challenges in predicting what the next several years will look like are enormous. Thus, there are significant consequences associated with imposing too high a rate increase on ratepayers over the next several years.

41.3.1 Attrition Is Intended to Mitigate Economic Volatility Between Test Years to a Reasonable Degree, Not to Cover All Potential Cost Changes.

The Attrition Rate Adjustment ("ARA") is a mechanism that the Commission has used to offset the financial risk experienced by the utilities between general rate cases. The Commission adopted the original attrition mechanism in 1980 during a period of very high inflation. 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."[1120]

[1119] Ex. TURN-24, UCLA Anderson Forecast, June 2020, pp. California-83, California-86.

[1120] D.04-05-055, p. 26, citing to D.85-12-076, Finding of Fact 1, 9 CPUC 2d 453, 476. *See also,* D.20-01-002, p. 41 (quoting TURN's comments which quoted and cited D.14-08-032, pp. 652-653).

The traditional attrition mechanism was a two-part mechanism, which separately determined the expense and capital portions of the attrition-year revenue requirement:

> 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.[1121]

However, the Commission has adopted one-part attrition mechanisms on a number of instances in the past and has made it clear that utility financial health is not the only criterion it considers in determining the appropriate level of attrition adjustment. In a number of cases the Commission has specifically found that a utility's attrition proposal placed too great a burden on ratepayers and has significantly reduced the authorized attrition amount.[1122] TURN submits that this is another proceeding where the Commission should balance its concern about SCE's continued access to the financial markets against its concern about ratepayers' ability to absorb rate increases, given the extent of current economic devastation combined with the strong likelihood that a weak economy will persist for several years.

41.3.2 SCE Confuses Attrition with Cost of Service Ratemaking.

SCE claims its proposed attrition mechanism is like "cost-of-service ratemaking" and asserts that awarding anything other than what SCE has requested undermines safe and reliable service.[1123] Yet the Commission has stated previously that the attrition rate adjustment "is not

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[1121] D.04-05-055, p. 27.

[1122] *See*, for example, D.09-03-025, pp. 305-306 and D.13-05-010, pp. 1009-1010.

[1123] Ex. SCE-18V4, p. 13-14.

intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee…rate of return."[1124] SCE claims 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.[1125] Yet, on a number of occasions, the Commission has specifically rejected reliance on SCE's forecasted capital budget, which is an integral part of SCE's attrition proposal, stating: "As we repeatedly observed in prior decisions, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned."[1126]

While the Commission may establish performance standards and determine reasonable revenue requirement, 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 greater and greater amounts of revenue requirement. Yet the Commission has previously granted SCE less revenue requirement than it had requested[1127] and has even reduced SCE's test year revenue requirement,[1128] 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

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[1124] D.14-08-032, p. 652.

[1125] Ex. SCE-18V4, p. 14.

[1126] D.09-03-025, p. 305, citing to D.04-07-022, p. 276.

[1127] D.09-03-025, pp. 5, 6.

[1128] 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.

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.[1129]

41.3.3 SCE's Claim that the Commission "Erred" in SCE's 2009 GRC Is Both Inaccurate and Misleading.

SCE witness Rumble brings up the same tired argument that the Commission "erred" in determining the appropriate increase for the 2010 and 2011 attrition years because the Commission's calculations overlooked SCE's year-end 2008 balance of Construction Work in Progress.[1130] However, contrary to witness Rumble's assertions, the Commission considered SCE's construction-work-in-progress balance along with every other aspect of SCE's financial situation and balanced SCE's concerns against the very real problems that ratepayers would face trying to absorb an increase of the level SCE proposed during the Great Recession. The Commission stated "We find that SCE's requested increases of approximately 5.54% for 2010 and 6.6% for 2011 are excessive based on the current economic conditions."[1131] The Commission did not entirely reject SCE's request but rather moderated it, granting the company a 4.25% and 4.35% increase in 2010 and 2011, respectively.

In claiming that the Commission erred, Witness Rumble is assuming that the Commission was bound to use SCE's proposed attrition mechanism, which relied upon complex

[1129] *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.").

[1130] SCE-07, Vol. 4A at 35-36.

[1131] D.09-03-025, pp. 305-306.

O&M escalators and SCE's budget based proposed capital additions levels to determine the attrition amount. However, it is witness Rumble and not the Commission who has erred. Witness Rumble assumes that the Commission is required to increase SCE's revenue requirement to offset cost increases, but the Commission has made it clear that attrition is not an inalienable right and has denied it previously.[1132] Furthermore, if the Commission chooses to grant an attrition increase for a utility, the Commission is not bound in any way to determine attrition based on a particular method. Over the years, the Commission has adopted a variety of attrition methods.[1133] Finally, the Commission has already rejected witness Rumble's argument on two previous occasions, stating the first time: "SCE's argument that the 2009 PTYR was fundamentally flawed because it underfunded capital additions in attrition years is unpersuasive."[1134] The Commission was more pointed the second time, calling incorrect SCE's claim that "cost-of-service ratemaking principles require some means to recognize these increases in the authorized revenue requirement."[1135] SCE is making precisely the same argument in this proceeding. Once again, the Commission should reject it.

41.4 Expenses Should Be Escalated by the Consumer Price Index.

41.4.1 SCE's Proposal is Too Generous to Shareholders.

SCE proposes that its PTY mechanism be based on the complex and proprietary indices that SCE proposes be used in establishing test year expense levels. While these indices may be appropriate for projecting test-year expenses, which the Commission establishes every three

[1132] D.96-01-011, 1996 Cal. PUC LEXIS 23, Part 5, at *48-49; D.00-02-046, p. 473.

[1133] *See*, for example, D.09-03-025, D.12-11-051, D. 13-05-010, and D.14-08-032.

[1134] D.12-11-051, p. 606.

[1135] D.19-05-020, Footnote 649.

(now 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.

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.[1136]

Indeed, as the Commission explained in D.14-08-032, "[W]e seek to promote [the utility's] incentive to stretch to achieve productivity between test years."[1137] 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, particularly in light of the devastating impact the COVID-19 outbreak has had on the California economy.

41.4.2 Use of CPI-U to Escalate Expenses for Attrition Years Will Help Offset Inflationary Pressures While Encouraging SCE to Stretch Between Test Years.

TURN proposes to escalate SCE's TY2021 O&M expenses by the CPI-U to determine the appropriate amount for O&M expenses in AY 2022; SCE's AY 2022 O&M expense levels would similarly be escalated by CPI-U to determine AY 2023 O&M levels.[1138] As an alternative, the Commission could escalate O&M using CPI-U increased by 50 basis points.[1139]

[1136] D.20-01-002, p. 41 (quoting TURN's comments which quoted and cited D.14-08-032, pp. 652-653).

[1137] D.14-08-032, p 652.

[1138] Ex. TURN-07, p. 17.

[1139] *Id.*, p. 18.

In this proceeding the Commission must consider whether SCE's proposed PTY mechanism with its myriad of account specific escalators best serves the Commission's purpose of promoting SCE to "stretch to achieve productivity" in AY 2022 and AY 2023. This purpose is always important, but with the economic crisis induced by the COVID-19 pandemic, TURN submits that the utilities owe it to their customers to improve the efficiency of their operations like never before. While economic conditions will hopefully have improved significantly by 2022, it is completely unreasonable to assume a full recovery for SCE's customers by the time the 2022 and 2023 revenue requirement increases take effect. With "apologies to Mother Goose," UCLA Anderson Forecast explains, "It will take time for all the king's horses and all the king's men to put the economy back together again."[1140]

The PTY escalation index that SCE requests using Global Insight's various utility cost forecasts is simply too protective of SCE to properly incent it to manage operations productively before its next GRC. Given the economic crisis induced by the COVID-19 pandemic, which introduces tremendous near-term economic uncertainty, the Commission should strike a different balance between ratepayers and shareholders for attrition years 2022 and 2023 than it did in SCE's previous (TY18) 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 Global Insight), is a reasonable method of achieving the Commission's purpose in providing attrition adjustments, particularly under today's circumstances. Using CPI to escalate O&M expenses would strike a better balance between ratepayer and utility interests.

[1140] TURN-24, UCLA Anderson Forecast, June 2020, p. Nation-13.

41.4.3 SCE's Criticisms of TURN's Proposal Are Unpersuasive.

SCE witness Rumble states that general measures of inflation such as the CPI do not adequately track utility cost increases because they do not "adequately" track the costs associated with utility operations.[1141] Instead, witness Rumble insists that the utility specific cost categories are the only ones appropriate for measuring cost increases associated with utility operations. These cost indices are too protective of the utilities as a group during this incredible economic downturn. Use of the indices that reflect only utility activities insulates the utilities from the economic realities facing the remainder of the country.

TURN submits that insulating SCE from economic reality during this severe downturn sends precisely the wrong message to SCE management and employees. Instead of telling them to "tighten their belts," they are being told to "spend freely" because their budgets will be escalated using utility specific indices that are completely separated from the economic reality faced by ratepayers. Instead, TURN's recommendation to escalate utility O&M costs with the CPI-U provides precisely the sort of economic signal that SCE should be receiving during the period of incredible economic distress. CPI-U makes sure that the basic level of inflation is reflected in increases to SCE's attrition expense levels, while ensuring the company does not remain disconnected from the economic reality facing its customers.

41.5 Wildfire and Non-Wildfire Related Capital Should Be Treated Differently for Purposes of Attrition in this GRC.

SCE witness Rumble would have the attrition mechanism for capital related costs (return, taxes, and depreciation expense) be even more SCE specific. "SCE's proposed methodology is to use SCE's budget-based forecast to set capital additions in the PTYR mechanism. As part of

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[1141] Ex. SCE-18V4, p. 21.

this methodology, SCE proposes to bifurcate non-wildfire capital additions from wildfire capital additions."[1142]

Under witness Rumble's proposal, the capital related costs would be based on SCE's capital budget forecast of spending for the rate case cycle that was adopted by the Board prior to the submission of SCE's GRC application in 2019. With all due respect to SCE's attempts to be accurate, no one is able to predict the future with complete certainty and long-range forecasts are the most uncertain. Therefore, the forecasts for the attrition years are most likely to vary widely from actual expenditures. Furthermore, SCE's projections were based on its 2019 expectations regarding economic growth in California during the test year and attrition years. Needless to say, those 2019 projections are sadly out of touch with reality.

SCE's capital-related forecast separates out wildfire related capital expenditures from non-wildfire related expenditures in order to the comply with the requirements of AB 1054, as discussed in Section 41.1. TURN agrees that this separation is appropriate. The proposed separation has the advantage of isolating the rapidly growing wildfire related capital expenditures from the remaining capital expenditures.

41.5.1 Given the Unique Circumstances Surrounding Wildfire-Related Capital Spending, the Commission Should Adopt Specific Capital Additions Levels for Each Attrition Year.

SCE has budgeted $800 million in wildfire related capital expenditures for the TY2021, increasing to over $900 million in AY2022 and $1.076 billion in AY2023.[1143] Because SCE has proposed such large levels of wildfire mitigation capital additions, TURN prepared an evaluation

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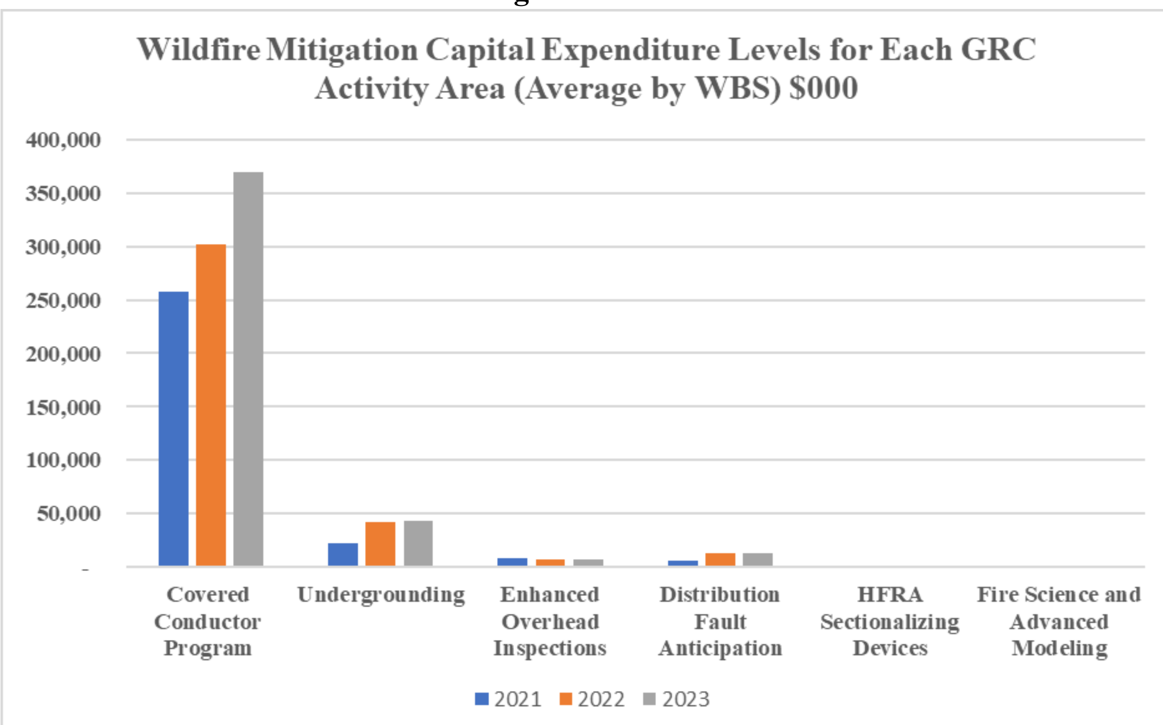
[1142] Ex. SCE-07V4A, p. 31.

[1143] *Id*., p. 34. These figures include amounts that will be removed from the results of operation for this proceeding and treated separately because they are banned from earning equity return per AB 1054.

of SCE's proposed activities for TY 2021, AY 2022, and AY 2023, which is discussed in Section 15.

Furthermore, as discussed by TURN witness Yap, SCE's wildfire related capital expenditures fall into only six Work Breakdown Structure ("WBS") categories. Figure 41-1 shows TURN's recommended level of capital expenditures for these six wildfire-related WBS categories by year:

Figure 41-1[1144]



Because the wildfire capital expenditures (which translate into capital additions) are so large and proposed to grow so substantially across the various years in the rate case cycle, TURN recommends specifically that the Commission adopt a level of capital additions for each

[1144] Ex. TURN-07, p. 8.

individual year, TY 2021, AY 2022, and AY 2023, instead of adopting an authorized level of capital additions for the test year and then escalating that test year level by some factor as the Commission has done in some previous GRCs. Reaching a decision about the specific level of wildfire capital spending by year ensures that the Commission has given consideration to the expenditure level that the Commission believes SCE is able to sustain over the entire three-year period. SCE does not object to TURN's proposal regarding wildfire capital additions except to take issue with the level of recommended expenditures.[1145]

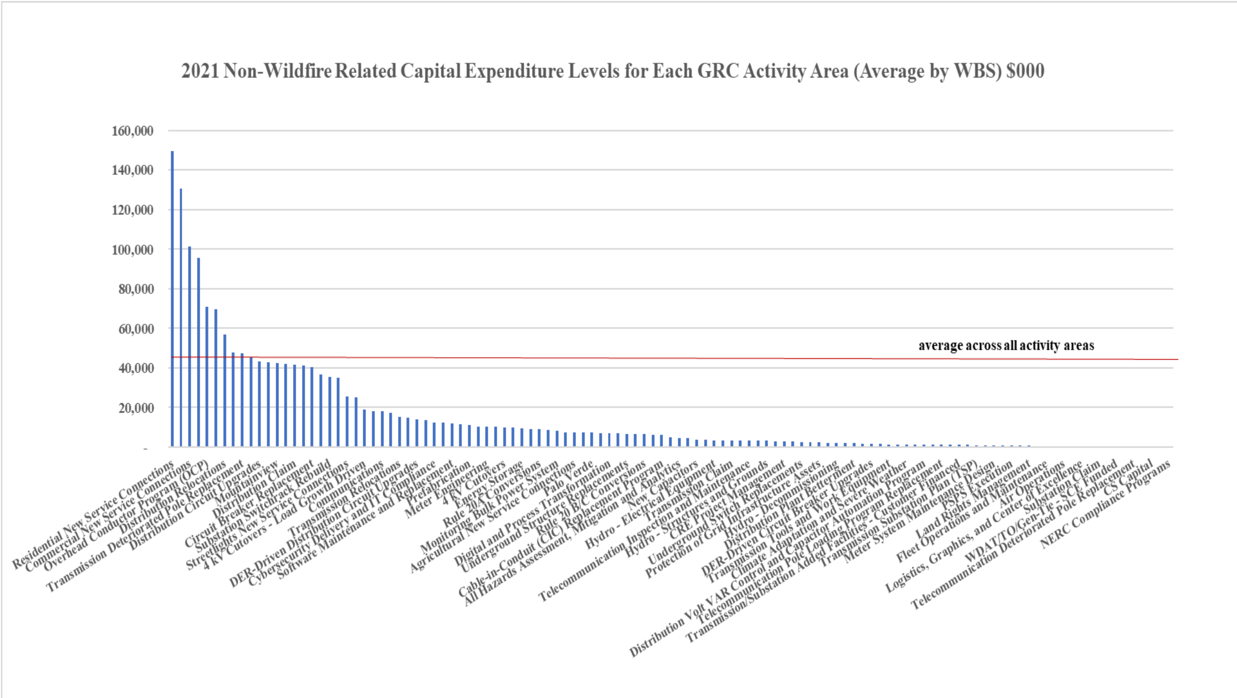
41.5.2 With the Exception of New Customer Connections, Non-Wildfire Related Capital Additions Should Be Based on Authorized Test Year Additions.

SCE's proposed non-wildfire mitigation capital expenditures (which translate into capital additions) address 415 WBS categories, which fall into approximately 120 activity areas.[1146]

[1145] Ex. SCE-18V4, p. 26.

[1146] Ex. TURN-07, p. 9.

Figure 41-2[1147]



As described by TURN witness Yap, the average size of the proposed capital expenditures by WBS varies significantly by GRC activity in the test year: "The largest 15 GRC activity areas have average capital expenditures that are between 3 and 10 times the $14 million average capital expenditure level considering all GRC activity areas. Overall, 27 GRC activity areas are above that average while the remaining 87 GRC activity areas are below that average."[1148]

Because of resource limitations, TURN makes recommendations for the levels of non-wildfire related capital additions in TY 2021, AY 2022, and AY 2023 for only two WBS

[1147] *Id.*, p. 10.

[1148] *Id.*, p. 9.

categories, Residential New Customer Connections and Commercial New Customer Connections.[1149] For the more than 100 remaining GRC activity areas, TURN recommends that the levels of capital additions in the attrition years remain flat in nominal terms relative to the adopted capital additions adopted for the test year because as noted in D.06-05-016 it would be inappropriate to adopt SCE's capital budget without rigorous review of each year's capital additions.[1150,1151] Given the overall size of the proposed wildfire capital additions and the projected rate of increase in those capital additions during the rate case cycle, it is appropriate that SCE keep the level of non-wildfire related capital additions constant. This is particularly important in light of the difficult economic situation expected to persist through the rate case cycle.

41.5.3 The Commission Should Dismiss SCE's Criticisms of TURN's Proposal.

SCE insists that the Commission adopt its budget-based capital forecast, claiming it reflects deferral of non-wildfire related projects to "keep customer costs as a reasonable level."[1152] However, the company's determination of "reasonable" was made in 2019 in the context of a thriving economy, not in the context of today's economy that has been devastated by the COVID-19 virus. SCE witness Rumble claims:

> SCE worked diligently to include only those essential non-wildfire projects so that SCE will be able to direct more capital funds towards helping California reduce wildfire risk. The result is a non-wildfire capital plan that has small

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[1149] *Id*. p. 10.

[1150] D.06-05-016, p. 306.

[1151] Ex. TURN-07, p. 20.

[1152] Ex. SCE-18V4, p. 24.

> nominal dollar increases in the attrition years, resulting in approximately 3% total growth over the Post-Test Year period.[1153]

In contrast, TURN proposes keeping non-wildfire related capital additions at a constant (test year) level throughout the rate case cycle in recognition of the serious economic conditions facing ratepayers.[1154]

SCE witness Rumble expresses appreciation of TURN's efforts to recommend year-by-year levels of wildfire related capital additions, but condemns TURN's recommended proposal as inadequate.[1155] As discussed in Section 15, TURN agrees with SCE's prioritizing wildfire related capital investments, but TURN has made its own evaluation of the amount of wildfire hardening that is appropriate during the rate case cycle.

However, TURN's alternative proposal regarding wildfire capital additions would have the Commission adopt wildfire related capital additions in real terms ($2018) rather than nominal terms.[1156] Such an approach would enable the company to adjust its capital additions to reflect the actual inflation rate associated with construction activities during the attrition years, rather than relying upon projections of inflation for a three-year period. SCE initially characterized TURN's proposal as "convoluted,"[1157] but acknowledged later that "if the Commission were to adopt PTYR capital expenditures in 2018 dollars, rather than SCE's budget-based proposal in nominal dollars" the Commission could escalate test-year capital expenditures "using IHS Markit's most recent capital escalation projections in Q4 of 2021 and 2022 for PTYR 2022 and

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[1153] *Id*., p. 28.

[1154] Ex. TURN-07, p. 20.

[1155] Ex. SCE-18V4, p. 26.

[1156] Ex. TURN-07, p. 20.

[1157] Ex. SCE-18V4, p. 28.

2023, respectively."[1158] TURN submits that it is reasonable for ratepayers to assume the inflation risk provided the overall level of wildfire related capital additions is reduced to reflect a more appropriate expectation about what the company should accomplish on a yearly basis.

42. COMPLIANCE REQUIREMENTS

43. ACCESSIBILITY ISSUES

44. RESULTS OF FINANCIAL EXAMINATION BY CAL ADVOCATES

45. GRC UPDATE PHASE

45.1 SCE's Vegetation Management Update Testimony Exceeds the Limited Scope for Such Testimony; SCE Will Have an Opportunity to Recover Any Costs Above Its Adopted Forecast Via the Memorandum Accounts Required By Public Utilities Code Section 8386.4

In testimony styled as "Update Testimony," SCE seeks to increase its 2021 O&M forecast for the four vegetation management (VM) programs addressed in Section 14 of this briefing outline by 50%, from $211.1 million to $316.6 million.[1159] The increases, broken down by program, are as follows:[1160]

Program	Increases to 2021 Forecast (2018 Constant $)
Distribution Routine Vegetation Management	$71,190,000
Transmission Routine Vegetation Management	$2,926,000
Dead, Dying and Diseased Tree Removal	$10,438,000
Hazard Tree Management Program (aka Wildfire Vegetation Management)	$20,936,000
Total	**$105,491,000**

[1158] Ex. TURN-23, TURN-SCE-098, Question 1.a.

[1159] Exhs. SCE-24E and 24 E2(Landrith/Pham), p. 3, Table III-1.

[1160] *Id.*, p. 3, Table III-2.

SCE claims that such significant forecast increases are appropriate to request via Update testimony because the increases are based on "known changes in cost of labor based on contract negotiations completed" and "known changes due to governmental action."[1161] The governmental action that SCE references is Senate Bill (SB) 247, which was signed into law on October 2, 2019.[1162]

As discussed in the remainder of this section, TURN's position is that these forecast cost increases exceed the scope of what the Commission has prescribed as appropriate Update testimony. The increases are not based on a straightforward application of known and uncontroversial rate increases that are specified in SB 247 or any particular labor contract(s) that SCE identifies in its testimony. Instead, the cost increases are derived numbers that are based on a variety of factors, some of which relate to SB 247 and some of which are based on claimed developments in the market for VM services that SCE asserts have caused vendor prices to rise significantly. Whether these cost increases are appropriate to recover from ratepayers is subject to controversy and requires considerably more analysis and process than the abbreviated Update procedure is designed to accommodate. Accordingly, the Commission should conclude that SCE's testimony exceeds the scope of proper Update testimony and should not be addressed in this GRC proceeding.

Importantly, rejecting consideration of SCE's VM testimony will not prejudice SCE's ability to recover costs of the type described by SCE, should such costs be incurred. As discussed in Section 34 of this brief, Public Utilities Code § 8386.4 allows SCE to track in a

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[1161] *Id.*, p. 1: 6-8.

[1162] *Id.*, p. 2: 9-10.

memorandum account WMP-related costs that are not covered in its revenue requirement. SCE may thus seek recovery of costs that exceed its adopted forecast in this case in a future application or GRC where it will be required to demonstrate the reasonableness of such costs in a proceeding that allows sufficient time for scrutiny of a major cost increase.

45.1.1 The Scope of Update Testimony Is Limited

The Commission's Energy Utility Rate Case Plan limits the scope of any update testimony in a GRC to three specified categories:

> A. Known changes in cost of labor based on contract negotiations completed since the tender of the NOI or known changes that result from updated data using the same indexes used in the original presentation during hearings.
>
> B. Changes in non-labor escalation factors based on the same indexes the party used in its original presentation during hearings.
>
> C. Known changes due to governmental action such as changes in tax rates, postage rates, or assessed valuation.[1163]

By their terms, each of these categories exclude cost changes that depend on assumptions or calculations that are subject to controversy. The examples that are given, such as changes in tax or postage rates, show that Update testimony should reflect incontrovertible rate increases for a cost input that the utility is simply applying to its previous testimony.

In the Administrative Law Judges' (ALJs) August 9, 2020 e-mail that granted TURN's motion to strike certain other Update testimony submitted by SCE, the ALJs disallowed Update testimony that was "dependent on new calculations, forecasts, and assumptions" and was "subject to controversy." As discussed in Section 45.1.2 below, the record shows that SCE's Update testimony has similar problems and is ultimately based on claimed cost increases that are

[1163] D.07-07-004, Appendix A, p. A-36.

far from incontrovertible and, in fact, subject to controversy regarding whether they are reasonable and should be recovered from ratepayers.

The strict limitations on Update testimony reflect the limited opportunity that the RCP schedule allows for scrutiny of such testimony, including a very short time period for discovery and preparation for evidentiary hearings, and no ability to submit responsive testimony. After thorough litigation of a utility's direct and rebuttal testimony, the utility should not be able to tack on a significant increase to its forecast based on information that is subject to controversy and not able to be sufficiently vetted and addressed by intervenors.

45.1.2 SCE's Testimony Exceeds the Limited Scope of Update Testimony

SCE's VM update testimony clearly does not fit within the scope of appropriate update testimony. As explained in this section, rather than simply applying known and uncontroversial rate changes that are attributable to governments actions, such as tax or postage rate changes, SCE's forecast increase is the result of a complex tangle of factors that flow from both SB 247 and changes in the market that caused vendors to seek higher prices. These factors require more time for analysis than the Update process affords and raise controversial issues regarding the reasonableness of SCE's efforts to limit the cost increases.

Although the cover to SCE's update testimony describes the forecast increase as "attributable to requirements in SB 247,"[1164] SCE is not relying on "known changes due to governmental action" as the sole basis for justifying its Update testimony. Instead, SCE asserts that its Update is also based on "known changes in cost of labor" based on completed contract

[1164] Ex. SCE-24 E (Landrith/Pham), cover page.

negotiations.[1165] However, SCE's testimony does not identify what portion of the cost increases are caused by SB 247 and what portion are attributable to factors other than SB 247. In cross examination, SCE's witness, Mr. Landrith, testified that the "majority" of the cost increases are related to SB 247, but that some are due to "new competitive market rates."[1166] With respect to the non-SB 247 causes, in a data request response, SCE identified various factors, including: the tight labor market, increased insurance costs, contractors' assessment of implementing GO 95 recommended clearance distances, and other factors that SCE was unable to identify.[1167] SCE also admitted that it was unable to estimate the impact of each of these non-SB 247 "drivers," contending that any such estimate would be "speculative."[1168]

These non-SB 247 factors identified by SCE do not fit under the heading of known changes in cost of labor, but instead result from a variety of claimed market forces that caused SCE's vendors to seek higher levels of compensation[1169] -- to the extent that SCE can identify the causes at all. The RCP rules do not allow Update testimony to be predicated on increases in vendor costs based on claimed changes in the marketplace, because analyzing and disentangling such issues is clearly too complex an endeavor for the abbreviated Update process. Moreover, because SCE does not know the portion of its cost increases that are caused by non-SB 247 factors, it is therefore also unable to identify the cost increases that are specifically attributable to SB 247 factors.

[1165] Ex. SCE-24 E, p. 1.

[1166] 12 RT 1298: 12 to p. 1299: 1 (Landrith/SCE).

[1167] Ex. SCE-55, SCE response to DR TURN-SCE 118-2.d Supplemental.

[1168] *Id.*

[1169] 12 RT 1303:18-25 (Landrith/SCE) (the claimed changes in cost of labor are actually changes in the costs of contracts that SCE has entered into with its vendors).

With regard to cost changes resulting from governmental action, the provision of SB 247 that SCE relies upon to justify its Update testimony states: "All qualified line clearance tree trimmers shall be paid no less than the prevailing wage rate for a first period apprentice electrical utility lineman as determined by the Department of Industrial Relations."[1170] Based on this language, the new minimum wage for tree trimmers is $34.85 per hour,[1171] as compared to pre-SB 247 hourly rates that, according to SCE ranged from roughly $15 to $18 per hour in 2019.[1172]

If, based on this change, SCE could simply show that its hourly wage rates have increased by, say $20 per hour, and apply that increased labor rate to the volumes identified in its previous testimony, SCE would have been able to present Update testimony akin to the changes in tax and postage rates for which the rate case plan allows Update adjustments. However, SCE does not and cannot do that. SCE's forecast costs are based not on hourly wage rates, but on "unit rates," which SCE states increased by 103% for trimming and 30% for removals.[1173] Unit rates differ from hourly rates in that they "represent a price negotiated with [SCE's] contractors (i.e. rate) . . . to complete a single trim job with a standard contractor crew."[1174] Thus, the unit rates that SCE uses do not isolate the wage rate increases mandated by SB 247, but include all of the non-SB 247 cost increases that vendors have sought to add to their contracts with SCE.

Furthermore, the 103% unit rate increase that SCE cites for trimming work is not just the result of increased rates charged by the same vendors that SCE used to prepare the forecast costs

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1170 SB 247, Section 2, codified at Public Utilities Code § 8386.6(b).

1171 Ex. TURN-79, SCE response to DR TURN-SCE 118-2.b.

1172 Ex. TURN-80, SCE response to DR TURN-SCE 118-2.c.

1173 Ex. SCE-24 E, p. 2: 17-18.

1174 Ex. TURN-87, SCE response to DR TURN-SCE 118-6.

for its direct testimony in this case. Contributing to the higher unit rate is the fact that SCE added two relatively higher cost vendors to the calculation of its new forecast.[1175] Again, SCE's Update is not simply the result of applying new, incontrovertible rates to their previous forecast volumes.

The sharp increases in vendor costs that cannot be directly attributed to specific mandates in SB 247 raise the question of whether SCE has acted reasonably in attempting to obtain the lowest possible costs for its VM work for 2021 and beyond. In this regard, one of the issues presented by SCE's Update testimony is whether, in light of the major price increases being sought by vendors, SCE should have used a new post-SB 247 competitive solicitation process. While SCE used such a process before SB 247, it did not do so after SB 247, even for work beginning in 2021.[1176] Whether SCE has acted prudently in not opening a new competitive solicitation, as well as other issues related to the reasonableness of the increased vendor prices that SCE expects to pay, cannot be fairly resolved in the abbreviated process for Update testimony. Such issues were never intended to be addressed in the Update phase of a GRC.

In sum, the cost increases in SCE's Update testimony fall well outside the scope of Update testimony. They are not based on known changes in rates due to SB 247 or labor contracts, but rather a variety of factors -- including changes in the market that are not caused by SB 247-- that cannot be directly quantified and specifically attributed to SB 247 or any

[1175] Ex. TURN-81C, SCE response to DR TURN 118-3.a, p. 2 (in the "Trimming" table, note that two vendors that were not part of the "GRC Application" calculation contributed to the new unit rate and that those two new vendors have higher "90/10 Split" costs than the other three vendors); 12 RT 1309: 13-28 (Pham/SCE).

[1176] 12 RT 1316: 14-23 and p. 1317: 10-14 (Landrith/SCE); Ex. TURN-82, SCE response to DR TURN-SCE 118-5.c.

particular labor contract. Instead, SCE's $105 million forecast cost increase is based on new calculations and assumptions about reasonable procurement practices that are subject to controversy. Such issues are not capable of being appropriately addressed in the truncated Update process.

45.1.3 Under PU Code Section 8386.4, SCE Will Have an Opportunity to Seek Recovery of Amounts In Excess of the Adopted Forecast

TURN's position to reject consideration of SCE's Update forecast in this GRC will not deprive SCE of an opportunity to recover costs of the type it identifies in its Update testimony. Under TURN's recommendation, the Commission will adopt a forecast for SCE's VM programs based on the parties' testimony and briefing related to the record of this case prior to the Update phase (which TURN addresses in Section 14 of this brief). As discussed in Section 34 above, if SCE incurs costs above its adopted forecasts for any of its four VM programs, SCE will have the opportunity to record those costs in the memorandum account for fire mitigation activities that is mandated by Public Utilities Code Section 8386.4(b)(1). Under Section 8386.4(b)(1), SCE can seek recovery of those costs in its next GRC, or by a separate application under Section 8386.4(b)(2). In either case, consistent with traditional legal requirements for rate cases, SCE will need to demonstrate that the costs in excess of its adopted forecast are reasonable and appropriate to recover from ratepayers.[1177] SCE would have this opportunity under either TURN's primary or alternative recommendations in Section 34 of this brief.

[1177] Public Utilities Code § 8386.4(b)(1) (Commission shall consider whether costs are "just and reasonable" and "shall review the costs in the memorandum accounts and disallow recover of those costs the commission deems unreasonable.")

Thus, SCE cannot legitimately complain that TURN's position prevents it from having a full and fair opportunity to recover costs of the type described in its Update testimony, should they materialize.

45.1.4 TURN's Recommendations

For the foregoing reasons, the Commission should conclude that: (1) SCE's testimony exceeds the scope of proper Update testimony and should not be addressed in this GRC proceeding; and (2) SCE may seek to recover costs for its VM programs in excess of the forecasts adopted in this case -- based on the pre-Update record -- via the memorandum account and processes set forth in Public Utilities Code Section 8386.4(b).

Alternatively, if the Commission (incorrectly) determines that SCE's Update testimony is appropriate for consideration and decision based on the truncated Update record in this case, then, for the reasons provided in Section 14.3 above, SCE's 2021 Update forecast for HTMP should be reduced to reflect removal of 4,000 (not 20,000) living trees. Under this alternative recommendation, SCE's 2021 Update forecast for HTMP would be reduced from $77.125 million to $32.818 million, a reduction of $44.306 million.[1178]

[1178] This reduction uses the same methodology shown in Ex. TURN-02, p. 44, which TURN applied to the line items for HTMP (Wildfire Vegetation Management) shown in Ex. SCE-24 WP E. TURN reduces: the line for Tree Removals from $51.7 million to $10.3 million; the line for Property Owner Incentives from $499,249 to $90,080; and the line for Property Management from $5.3 million to $2.8 million.

46. STIPULATIONS AND POST-FILING CONCESSIONS

47. MISCELLANEOUS/OTHER ISSUES

48. REQUEST FOR ORAL ARGUMENT

Pursuant to Rule 13.13 of the Commission's Rules of Practice and Procedure and the *Assigned Commissioner's Scoping Memo and Ruling* issued November 25, 2019, TURN requests that the Commission direct the presentation of oral argument in this proceeding.

49. CONCLUSION

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Date: September 11, 2020

Respectfully submitted,

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