

Decision 21-08-036 August 19, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) 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

**DECISION ON TEST YEAR 2021 GENERAL RATE CASE
FOR SOUTHERN CALIFORNIA EDISON COMPANY**

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APPENDIX A – List of Acronyms

APPENDIX B – Results of Operations 2021-2023

**DECISION ON TEST YEAR 2021 GENERAL RATE CASE
FOR SOUTHERN CALIFORNIA EDISON COMPANY**

Summary

This decision approves a test year (TY) base revenue requirement of \$6.899 billion for Southern California Edison Company (SCE) pursuant to its 2021 General Rate Case (GRC) Application 19-08-013. The adopted amount is a 7.63 percent increase over SCE's currently authorized revenue requirement compared to SCE's requested 19.03 percent increase and reflects our careful assessment and determination of the operating expenses and capital expenditures that are necessary for SCE to provide safe and reliable service at just and reasonable rates. The adopted 2021 revenue requirement shall become effective upon the filing of tariffs pursuant to the directives of this decision.

This decision also authorizes post-test year revenue requirement adjustments of \$382 million for 2022 (a 5.54 percent increase) and \$437 million for 2023 (a 6.00 percent increase). These adjustments provide funds necessary for SCE to continue to provide safe and reliable service to customers beyond the test year, while providing SCE a reasonable opportunity to earn the rate of return authorized by the Commission in Decision 19-12-056.

Based on the date of issuance of this decision, we direct SCE to implement the TY 2021 revenue requirement in rates beginning October 1, 2021. Given the timing of this implementation, and in consideration of public comments regarding the impact of bill increases and affordability concerns, particularly during the ongoing COVID-19 pandemic, we find it reasonable to specify that the incremental revenue increase that has accrued from January 1, 2021 through September 30, 2021 shall be amortized over a twenty-seven month period, beginning October 1, 2021 to December 31, 2023.

With this amortization, the estimated impact of the approved revenue requirement in 2021 is an average residential monthly bill increase of approximately \$12.41, or 8.9 percent, for non-CARE¹ customers and \$8.39, or 8.9 percent, for CARE customers.² Granting SCE's full request (without amortization) would have resulted in an average residential monthly bill increase of \$16.77, or 12.1 percent, for non-CARE customers and \$11.33, or 12.1 percent, for CARE customers in 2021.

A significant component of SCE's request in this application is for capital expenditures, particularly as it relates to mitigating wildfire risk. The impact of current capital expenditures on current revenue requirements may be limited and incremental, but the cumulative impact is powerful over time as the value of capital assets (including rate of return and cost of removal) is repaid by ratepayers. SCE requests approximately \$5.205 billion in capital expenditures during 2021 alone. We approve approximately \$4.928 billion of total capital expenditures, reflecting our judgement that the long-term benefits of these investments justify the costs. However, we also deny notable portions of SCE's request for expenditures that SCE has not demonstrated are just and reasonable costs of safe and reliable service.

Appendix B to this decision contains the detailed results of operations tables that summarize the annual GRC revenue requirements approved in this decision for 2021-2023, based on our decisions regarding the forecasted costs we find reasonable, and which are adopted in today's decision. This decision does

¹ California Alternate Rates for Energy.

² The bill impacts are estimates for illustrative purposes only based on monthly residential customer usage of 550 kilowatt hours/month, current base revenue requirement of \$5.898 billion, and current rates as of June 2021. The bill impacts include one-time memorandum account recovery addressed in Sections 39.2.1 and 39.2.2, as well as GRC revenue growth.

not address recorded expenditures tracked in SCE's various wildfire-related memorandum accounts, or the approval of funding for a third attrition year covering 2024, which are the subject of separate decisions in this proceeding. The revenue requirement authorized in this decision also does not include commodity costs of electricity procured for customers or costs of fuel used in generating electricity, which are the subject of a separate proceeding.

This proceeding remains open.

1. Factual Background

Southern California Edison Company (SCE) provides electric service to more than 15 million California residents through approximately 4.5 million residential and 0.6 million commercial and industrial customer accounts.³ SCE's service territory is located throughout central and southern California and includes approximately 200 incorporated communities as well as outlying rural territories.

In this General Rate Case (GRC) Phase 1 application,⁴ SCE requests an authorized base revenue requirement of \$7.629 billion to become effective January 1, 2021.⁵ SCE's request represents a \$1.220 billion, or 19.03 percent,

³ Ex. SCE-01, Vol. 1 at 1; Ex. SCE-18, Vol. 5 at 12, Figure III-1.

⁴ In Phase 1 of a GRC proceeding, the Commission determines the utility applicant's electric system revenue requirements and addresses related issues. Phase 2 of the GRC follows a separate application and addresses marginal cost, revenue allocation, and rate design matters.

⁵ Ex. SCE-52A2E2 at 7, Table II-3. This reflects SCE's most recent request in its Second Errata to Second Amended Update Testimony.

Unless otherwise specified, all Operations and Maintenance (O&M) budgets presented in this decision are in \$2018 and all capital expenditure budgets are in \$nominal. Further, unless otherwise specified, all the forecasts presented in this decision are on a total company basis. The method for determining the California Public Utilities Commission (CPUC)-jurisdictional revenue requirement is addressed in Section 45.1.

increase in 2021 over currently authorized base rates.⁶ SCE requests additional base revenue requirement increases of \$452.0 million (or 5.9 percent) in 2022 and \$524.1 million (or 6.5 percent) in 2023.⁷

SCE acknowledges that the increase it is requesting is larger than what it has sought in the recent past.⁸ However, SCE contends that its request is required to fund the necessary costs to safely, efficiently, and effectively operate, inspect, maintain, support, or augment SCE's electrical grid and other vital infrastructure and support functions. In particular, SCE highlights the pressing need to undertake significant measures to reduce wildfire risk, as set forth in its Grid Safety & Resiliency Program and Wildfire Mitigation Plan filings.⁹

Many parties to the proceeding reviewed SCE's application and oppose various requests or recommend adjustments.

2. Procedural History

On August 30, 2019, SCE filed Application (A.) 19-08-013 for Authority to Increase its Authorized Revenues for Electric Service in 2021, among other things, and to Reflect that Increase in Rates (Application). SCE's Application also included a request to recover certain recorded expenditures being tracked in various wildfire-related memorandum accounts (MAs).

Protests to the application were timely filed by The Utility Reform Network (TURN); National Diversity Coalition (NDC); and the Public Advocates Office (Cal Advocates). Responses were timely filed by Pacific Gas and Electric

⁶ *Ibid.* Including increases attributable to a decline in revenue growth and recovery of memorandum accounts would result in an increase of \$1.273 billion or 20.03 percent.

⁷ *Ibid.*

⁸ Ex. SCE-01, Vol. 1 at 1.

⁹ *Id.* at 1-2.

Company (PG&E); Small Business Utility Advocates (SBUA); jointly by the California Choice Energy Authority and Clean Power Alliance of Southern California (collectively, SoCal CCAs); and jointly by the Solar Energy Industries Association (SEIA) and Vote Solar.

In addition, the following parties requested and were granted party status in the proceeding: San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas); Agricultural Energy Consumers Association; Coalition of California Utility Employees (CUE); Energy Producers and Users Coalition (EPUC); Center for Accessible Technology (CforAT); the Engineers and Scientists of California, Local 20, International Federation of Professional & Technical Engineers, and AFL-CIO & CLC (jointly); California Cable & Telecommunications Association (CCTA); and Conterra Ultra Broadband Holdings, Inc. (Conterra).

On October 14, 2019, SCE filed a Reply to the Protests and Responses.

A prehearing conference (PHC) was held on October 30, 2019, to determine the parties and discuss the scope of issues, categorization, schedule of the proceeding, and other procedural matters. During the PHC, SCE stated its intent to submit an amended application.

On November 7, 2019, SCE submitted its amended application.

On November 25, 2019, the assigned Commissioner issued a Scoping Memorandum and Ruling (Scoping Memo) setting forth the scope of issues, need for hearing, schedule, and category. The Scoping Memo divided the procedural schedule into three tracks: Track 1 considers SCE's forecast revenue request for 2021-2023, encompassing all the issues generally considered in Phase 1 GRC applications. Track 2 includes review of 2019 recorded costs in the Wildfire Mitigation Plan MA, 2019 recorded costs in the Fire Risk Mitigation MA, and

2018-2019 recorded costs in the Fire Hazard Prevention MA. Track 3 includes review of any 2018-2020 recorded costs in the Grid Safety and Resiliency Program MA above the settlement amount being considered in A.18-09-002, recorded 2020 costs in Wildfire Mitigation Plan MA, recorded 2020 costs in the Fire Risk Mitigation MA, and recorded 2020 costs in the Fire Hazard Prevention MA.

On January 22, 2020, the Commission issued Decision (D.) 20-01-002, which modified the GRC cycle for large energy utilities from a three-year to a four-year cycle and directed SCE to update its current GRC application to add a third attrition year for 2024.

On April 17, 2020, the assigned Commissioner issued an amended Scoping Memorandum and Ruling (Amended Scoping Memo). Pursuant to the direction in D.20-01-002, the Amended Scoping Memo added a Track 4 to consider funding for a third attrition year covering 2024.

On May 5, 2020, due to guidance from the California Department of Public Health concerning restrictions on public gatherings to protect public health and slow the spread of COVID-19, the assigned Administrative Law Judges (ALJs) issued a ruling noticing remote public participation hearings (PPHs) for Track 1 of the proceeding. Two PPHs per day were held on June 30, 2020, and July 1, 2020.

Due to ongoing restrictions on public gatherings, evidentiary hearings for Track 1 were held virtually from July 6, 2020, to July 22, 2020. An evidentiary hearing to address update testimony was held virtually on August 12, 2020.

On August 27, 2020, the ALJs issued a ruling adopting corrections to the Reporter's Transcript (RT) for the evidentiary hearings.

On September 9, 2020, SCE and Conterra filed a Joint Motion for Approval of 2021 General Rate Case Settlement Agreement, which addressed certain fees SCE charges related to pole attachments.

On September 9, 2020, SCE, SEIA, and Vote Solar filed a Joint Motion for Approval of 2021 General Rate Case Settlement Agreement, which addressed issues related to the development of future solar photovoltaic (PV) data and analysis.

On September 10, 2020, SCE and SoCal CCAs filed a Joint Motion for Approval of 2021 General Rate Case Settlement Agreement, which addressed certain Community Choice Aggregation (CCA)-related fee modifications, as well as CCA-related data and process improvements.

On September 11, 2020, the following parties filed Track 1 Opening Briefs (OBs): SCE, Cal Advocates, TURN, SBUA, NDC, CUE, EPUC, and SDG&E.

On September 17, 2020, SCE filed a motion to strike portions of Cal Advocates' OB on Grid Modernization (Grid Mod). Cal Advocates filed a response to the motion on September 24, 2020. On September 29, 2020, the ALJs issued a ruling granting, in part, and denying, in part, SCE's motion.

On October 2, 2020, the following parties filed Track 1 Reply Briefs (RBs): SCE, Cal Advocates, TURN, SBUA, NDC, CUE, EPUC, and PG&E.

On November 5, 2020, SCE filed a motion to establish a 2021 General Rate Case Revenue Requirement Memorandum Account; the motion was granted by ruling on November 23, 2020.

On January 6, 2021, the assigned ALJs issued a ruling to adopt procedures for the confidential production of computer model runs using SCE's Results of Operations model to generate tables needed for decision support in this proceeding.

At SCE's and TURN's requests pursuant to Rule 13.14 of the Commission's Rules of Procedure,¹⁰ the Commission held an oral argument on July 26, 2021 in order to provide parties the opportunity to address the Commission on the issues in Track 1 of this proceeding. Track 1 was submitted for the Commission's decision on this date.

3. Evidentiary Standards and Burden of Proof

Public Utilities Code Section 451¹¹ provides that "all charges demanded or received by any public utility ... shall be just and reasonable." Pursuant to Section 454(a):

a public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

It is well-established that, as the applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application.¹² The Commission has held that the standard of proof the applicant must meet in rate cases is that of a preponderance of the evidence.¹³ Preponderance of the evidence usually is defined "in terms of probability of

¹⁰ SCE OB at 404. During the pendency of this proceeding, former Rule 13.13 governing oral arguments in ratesetting and quasi-legislative proceedings was renumbered as Rule 13.14. All subsequent references to a Rule are to the Commission's Rules of Practice and Procedure, unless otherwise specified.

¹¹ All subsequent section references are to the Public Utilities Code, unless otherwise specified.

¹² D.09-03-025 at 8; D.06-05-016 at 7.

¹³ D.19-05-020 at 7; D.15-11-021 at 8-9; D.14-08-032 at 17.

truth, *e.g.*, ‘such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.’”¹⁴

Although the utility bears the ultimate burden to prove the reasonableness of the relief they seek and the costs they seek to recover, the Commission has held that when other parties propose a different result, they too have a “burden of going forward” to produce evidence to support their position and raise a reasonable doubt as to the utility’s request.¹⁵

Since the evidence and arguments in this proceeding are voluminous, the discussion in this decision focuses on the major points of contention and does not provide detailed summaries of the evidence and arguments for every issue. However, we have reviewed and considered the exhibits in this proceeding pertaining to each section, the evidentiary hearing transcripts, and all the arguments raised by the parties, in deciding the revenue requirements and related policy directives adopted in this decision. As a general matter, with respect to individual uncontested issues in this proceeding, we find that SCE has made a *prima facie* just and reasonable showing, and adopt the proposal, unless otherwise stated.

With respect to any settlement agreement, pursuant to Rule 12.1(d), we will only approve settlements that are reasonable in light of the whole record, consistent with the law, and in the public interest. Proponents of a settlement agreement have the burden of proof of demonstrating that the proposed settlement meets the requirements of Rule 12.1 and should be adopted by the Commission.¹⁶

¹⁴ D.08-12-058 at 19, citing Witkin, *Calif. Evidence*, 4th Edition, Vol. 1 at 184.

¹⁵ D.20-07-038 at 3-4; D.87-12-067 at 25-26, 1987 Cal. PUC LEXIS 424, *37.

¹⁶ D.12-10-019 at 14-15; D.09-11-008 at 6.

4. PPHs and Correspondence

The Commission held four remote PPHs on June 30, 2020, and July 1, 2020. The remote PPHs were held to provide SCE's customers with an opportunity to communicate directly with the Commission regarding the Application and SCE's proposed rate increases. The assigned Commissioner and assigned ALJs attended all the PPHs.

At each of the PPHs, the assigned ALJs provided a background of the Commission, the proceeding process, and a summary of SCE's application. Parties were given the opportunity to make presentations at the PPHs. SCE, Cal Advocates, TURN, and NDC made brief presentations.

Of the general public who spoke at the PPHs, almost all opposed SCE's proposed rate increase, particularly the steep increase proposed for 2021 and having to commit to increases for the next three years. Many speakers raised concerns that SCE's proposed rate increases were ill-timed and unreasonable due to the hardships caused by COVID-19, including loss of income due to unemployment, greater energy consumption while sheltering in place, increased risk of eviction, COVID-19 related healthcare costs, and uncertainty of the duration of the pandemic. A number of speakers suggested that any rate increase should be gradual and be the smallest in the first year.

Speakers also raised concerns regarding the affordability of SCE's requests. Several speakers who were on assistance programs or on fixed incomes stated that they were making ends meet but could not pay beyond their current means. Others stated that though they do not qualify for low-income programs, they still struggle to pay utility bills and would not be able to afford the increase in rates. Some speakers opposed the increases due to already high rates for heating and cooling in communities with extreme temperatures, and raised concerns

regarding heat-related health issues for vulnerable people who decide to forgo air conditioning to lower their energy bills. Several speakers who made energy efficiency and renewable energy improvements stated that they saw little or no reduction in energy costs and were against further cost increases.

A few speakers urged SCE to make further cuts. Speakers commented on the need for more transparency in how the increase in rates would directly address wildfire issues. Many were concerned that the rate increase would mostly benefit SCE management and shareholders.

In addition to the comments at the PPH, over 3,600 written public comments were submitted in this proceeding. Among the public comments received, more than 99 percent oppose SCE's proposed rate increase, less than one percent support the rate increase, and a few comments support a smaller rate increase in line with cost-of-living adjustments. Many of the written public comments reiterate concerns voiced during the PPHs. Approximately one-third of public comments state that there should not be any rate increase during the COVID-19 pandemic, with particular focus on the associated high rate of unemployment. The public comments also raise concerns that rates are already too high and that customers, particularly those who are low-income, retired, or on fixed incomes, cannot afford additional increases. Many of the public comments also state that shareholders, rather than ratepayers, should pay for SCE's high management salaries and SCE's failure to maintain its infrastructure and equipment. Several comments also assert that the rates for solar energy are unfair.

5. Policy

While acknowledging the financial magnitude of its GRC request, SCE asserts it has prioritized programs and activities that are necessary and prudent

to protect customers and communities from public safety risks, maintain and improve customer service, and implement the State's ambitious public policy goals. SCE attributes the most significant driver of incremental funding in this GRC cycle to the "pressing need to undertake significant measures to reduce wildfire risk."¹⁷ SCE's wildfire safety measures expand upon the foundations set forth in SCE's Grid Safety & Resiliency Program (GSRP) and Wildfire Mitigation Plan (WMP) filings, encompassing activities and costs attributed to system hardening, improved situational awareness, expanded inspections and vegetation management programs, enhanced public outreach and operational practices, and the continuation of wildfire liability-related insurance protection.¹⁸ SCE seeks recovery of two distinct sets of wildfire-related costs in this proceeding: first, consistent with traditional Phase 1 GRCs, SCE forecasts wildfire-related expenditures it deems necessary to protect the public and safeguard the electric grid over the 2021-2023 GRC cycle. These forecasts are the subject of this decision. Second, SCE seeks review and recovery of incremental recorded wildfire mitigation costs tracked in a variety of Commission-authorized MAs. These recorded wildfire mitigation costs are addressed in Track 2 and Track 3 of this proceeding.¹⁹ While SCE seeks a Commission determination that all wildfire-related capital expenditures are just and reasonable, pursuant to Assembly Bill (AB) 1054 (Stats. 2019), SCE excludes from this proceeding the

¹⁷ Ex. SCE-01, Vol. 1 at 2.

¹⁸ *Id.* at 1-8.

¹⁹ The Commission adopted a Track 2 settlement agreement addressing SCE's recorded 2018-2019 wildfire mitigation MA costs on January 14, 2021. (*See* D.21-01-012.) A Proposed Decision addressing Track 3 issues is anticipated in Q1 of 2022. (*See* ALJs' Email Ruling Granting Cal Advocates' Request for Modifications to the Track 3 Schedule, dated June 15, 2021.)

revenue requirement associated with \$1.575 billion in wildfire-related capital expenditures that are not eligible for an equity rate of return.²⁰

SCE's proposed wildfire mitigation activities, and associated risk-based analyses, are built upon numerous Commission decisions and legislative action designed to reduce the risk of utility-caused wildfires, including the CPUC's High Fire-Threat District map,²¹ the implementation of electric utility wildfire mitigation plans pursuant to Senate Bill (SB) 901 (Stats. 2018),²² the development of a risk-informed decision-making framework consistent with the Commission's Safety Model Assessment Proceeding²³ and SCE's Risk Assessment Mitigation Phase filing,²⁴ and the approved settlement in SCE's Grid Safety and Resiliency Program proceeding.²⁵

Concurrent with the need to mitigate increasing wildfire risk, on March 19, 2020, approximately six months after SCE filed its GRC application, the Governor signed Executive Order N-33-20 requiring all individuals living in the State of California to stay home or at their place of residence, except as needed to maintain continuity of operation of the federal critical infrastructure sectors, in order to address the public health emergency presented by the

²⁰ Pursuant to AB 1054, recovery of the revenue requirement deemed just and reasonable in this proceeding will occur through a separate application requesting a financing order. (Ex. SCE-01, Vol. 1 at 2; also, D.20-11-007.)

²¹ See D.17-12-024, as modified by D.20-12-030.

²² See Pub. Util. Code § 8386 and Commission Rulemaking 18-10-007.

²³ The S-MAP proceeding addresses applications A.15-05-002 (San Diego Gas & Electric Co.), A.15-05-003 (Pacific Gas & Electric Co.), A.15-05-004 (Southern California Gas Co.) and A.15-05-005 (SCE). A new rulemaking (R.20-07-013) will consider ways to strengthen the risk-based decision-making framework that regulated energy utilities use to assess, manage, mitigate, and minimize safety risks.

²⁴ See Investigation 18-11-006; also, Ex. SCE-01, Vol. 2.

²⁵ See D.20-04-013.

COVID-19 pandemic.²⁶ While “no stakeholder knows to any reasonable degree what the ultimate impacts of the COVID-19 pandemic will be on SCE’s costs, or what the timing associated with those impacts will be,”²⁷ it is generally undisputed among the parties that the economic impacts from COVID-19 are significant and ongoing.

Cal Advocates and TURN challenge many aspects of SCE’s GRC request, including the scope of SCE’s primary wildfire grid hardening solution presented in this GRC, referred to as the Wildfire Covered Conductor Program (WCCP). Cal Advocates’ and TURN’s positions are premised both on an evaluation of the individual showings for each program/activity, as well as broader consideration of how SCE’s overall GRC request impacts customer access and affordability, particularly in light of the COVID-19 pandemic.

On these broader points, TURN asserts that a substantial portion of SCE’s request is tied to activities or costs that could have been excluded from this GRC cycle, including SCE’s proposals to change the net salvage rates used to calculate depreciation expense, increase employee compensation programs, increase initial recovery of future decommissioning costs, accelerate capitalized wildfire insurance costs, and end the Aged Poles disallowance.²⁸ As discussed below, TURN also argues that SCE’s GRC request is far from affordable.²⁹ Cal Advocates proposes a downward adjustment of \$125 million to SCE’s estimated 2020 capital expenditure budget based on the recent economic

²⁶ CA Executive Order N-33-20. Available at: <https://covid19.ca.gov/img/Executive-Order-N-33-20.pdf>. Last accessed June 11, 2021.

²⁷ Ex. SCE-12, Vol. 1 at 11.

²⁸ TURN OB at 5-6.

²⁹ *Id.* at 11.

downturn associated with the COVID-19 pandemic. Cal Advocates asserts its testimony and GRC forecasts were developed with a business-as-usual approach prior to the pandemic, and that its relatively modest adjustment takes into consideration the dramatic economic changes that have occurred since COVID-19.

In response, SCE asserts its GRC request is necessary to adequately fund vital public safety initiatives, maintain reliability, and provide excellent customer service, and that today, more than ever, customers need their utilities to help keep them safe from wildfires, and to continue to provide safe, reliable, clean, and affordable service.³⁰ SCE further asserts that, with the exception of accelerated recovery of capitalized wildfire insurance costs, none of the expenses TURN identifies as potentially being excluded from this GRC request are optional.³¹ Lastly, SCE states that while it is sensitive to the effects the ongoing pandemic is having on its customers and communities, Cal Advocates' proposed \$125 million reduction is premature and lacks supporting evidence or analysis.³²

SCE is required by law to "promote the safety, health, comfort, and convenience of its patrons, employees, and the public" while including only "just and reasonable" charges in its rates.³³ A fundamental challenge in many disputed areas of this proceeding is to reach an outcome consistent with these two, often competing, objectives. While this is a familiar challenge present in numerous past GRCs, the rate impacts are real and will be uniquely felt by

³⁰ SCE OB at 6-8.

³¹ SCE asserts its proposal to accelerate recovery of capitalized wildfire insurance costs is consistent with FERC guidance, but recognizes that maintaining the status quo is also a legitimate policy outcome given the rate impacts of SCE's proposal. (SCE RB at 4-5.)

³² Ex. SCE-12, Vol. 1 at 11-13.

³³ Pub. Util. Code § 451.

customers in the context of the ongoing COVID-19 pandemic. Over the course of the past year the Commission has put into place a variety of measures to help protect residential and small business customers during the COVID-19 crisis. Some of these protective measures include, but are not limited to, a moratorium on disconnections for nonpayment, suspension of late fees and deposits, freezing program removals for the California Alternate Rates for Energy/Family Electric Rate Assistance programs, and temporarily reducing the high usage charge.³⁴ In this decision, we continue our commitment to maintaining affordable rates and protecting customers in the face of COVID-19 by ensuring rate increases are only approved for programs and activities which SCE has shown to be necessary and consistent with the provision of safe, reliable, and affordable service.

At the same time, the increasing threat of catastrophic wildfires has made wildfire mitigation a high priority for the State and this Commission (*See* Section 17.2.2). Our review of SCE's wildfire-related expenses is aided both by the robust party participation throughout this proceeding, as well as the risk-based decision-making framework SCE incorporates throughout its GRC application and testimony. The approved wildfire-related funds in this decision are significant, covering a diverse portfolio of mitigations, including the largest deployment of covered conductor in high-fire risk areas among California's large investor-owned utilities. However, this decision also makes substantial reductions to SCE's forecasts, focusing on wildfire mitigation measures that are cost-effective and that target SCE's highest risk circuits.

³⁴ *See* Resolution M-4842, Resolution M-4849, and D.20-05-013. While many of the COVID-19 emergency protection orders expired on June 30, 2021, the Commission adopted longer-term policies to reduce residential customer disconnections in D.20-06-003.

The amounts authorized in this decision are tied to SCE's individual requests for proposed programs and activities, and reflect our assessment of the operating expenses and capital expenditures necessary for SCE to provide safe and reliable service at just and reasonable rates. While the economic impacts from COVID-19 have been carefully considered in our evaluation of each of SCE's requests, we do not find sufficient evidentiary basis to support Cal Advocates' broader \$125 million reduction. Cal Advocates' adjustment is based on an estimated 25 percent reduction in capital expenditures in the Functional Area of New Service Connections & Customer Requested System Modifications, which Cal Advocates asserts is most likely to be impacted by the abrupt change in current and ongoing economic conditions.³⁵ Cal Advocates does not provide any analysis or evidence in support of its recommendation, or attempt to explain how it arrived at the 25 percent figure used to calculate the reduction. Although we do not find basis for a 25 percent reduction to these forecasts, as discussed in Section 14.1, we adopt reductions to SCE's New Service Connection forecasts based on our review of each of the individual budgets. Moreover, we make substantial reductions to the activities or costs that TURN asserts could have been excluded from this GRC request, as described in the relevant sections throughout this decision.

6. Affordability

As discussed above, the Commission has a mandate to ensure it only authorizes costs that are just and reasonable and necessary for the provision of safe and reliable service. The Commission has emphasized that, "a key element of finding a charge or rate just and reasonable is whether that charge or rate is

³⁵ Ex. PAO-01 at 8.

affordable.”³⁶ Section 382(b) states “recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures.” Further, Section 739(d)(2) directs that the Commission “shall ensure that rates are sufficient ... to recover a just and reasonable amount of revenue ... while observing the principle that electricity and gas services are necessities, for which a low affordable rate is desirable.”

6.1. Affordability Metrics

6.1.1. SCE’s Metrics

SCE presents several metrics to assess the affordability of SCE’s rates, which take into consideration the requests in this proceeding, as well as pending cost recovery requests in other proceedings.³⁷ These metrics include the following: (1) SCE’s system average rate (SAR) over time relative to local area inflation; (2) SCE’s rates compared to other major electric investor-owned utilities (IOUs) in California; (3) SCE’s rates and customers’ bills compared to IOU customers around the country; (4) energy burden, which is defined as the percentage of a household’s annual income that is spent on electricity; and (5) hours at minimum wage, which describes the hours it takes for a household

³⁶ D.19-05-020 at 11.

³⁷ The other proceedings SCE considers include the cost of capital proceeding (A.19-04-014), the Catastrophic Expense Memorandum Account proceeding (A.19-07-021), the Wildfire Expense Memorandum Account proceeding (A.19-07-020), two transportation electrification proceedings (A.18-06-015 and A.18-07-022), and other energy efficiency and demand response-related forecasts. (Ex. SCE-07, Vol. 4A at 3-4.)

earning minimum wage to pay for essential electric services.³⁸ SCE maintains that these metrics, when considered collectively, demonstrate that SCE's request in this GRC and other proceedings produce affordable bills for essential electrical utility service. SCE also contends that its proposed rate increases, while significant, are necessary to provide customers with safe and reliable service, including a reduction of wildfire risk.

SCE's data shows its SAR has generally tracked Los Angeles area inflation over the last 30 years.³⁹ Since 2009, SCE's SAR has risen more slowly (12 percent increase) compared to the other major California IOUs (45 percent and 37 percent increases for SDG&E and PG&E, respectively) and the Consumer Price Index (CPI) (19 percent increase).⁴⁰ SCE also compares its average 2018 residential rates and bills to the 50 largest IOUs nationwide and shows that, though SCE's rates are relatively high compared to most of the other IOUs, SCE customer bills rank among the lowest due to the mild climate and energy efficient buildings in its territory.⁴¹

SCE's data shows that inflation-adjusted residential average bills are slightly lower in 2019 than they were in 1998 in real terms, though over that period there were considerable spikes and dips in the average bill on a real basis.⁴² SCE acknowledges that approval of the pending rate recovery proposals

³⁸ Ex. SCE-07, Vol. 4A at 1-2. SCE uses the baseline allowance as the essential usage level, which is consistent with the definition of essential usage adopted in D.20-07-032. (D.20-07-032 at 21.)

³⁹ Ex. SCE-07, Vol. 4A at 4, Figure II-1.

⁴⁰ *Id.* at 7, Figure II-4.

⁴¹ *Id.* at 8-9.

⁴² *Id.* at 5, Figure II-2.

in this GRC and other proceedings will depart from this trend and result in a near-time spike.⁴³

SCE evaluates the estimated change in energy burdens (from current bills to projected 2023 bills) grouped by income status using the conservative assumption that household income will remain static from 2019-2023. With these parameters, SCE estimates that the average energy burden from 2019-2023 will increase from 3.0 percent to 4.1 percent for California Alternate Rates for Energy (CARE) customers and from 2.8 percent to 4.0 percent for non-CARE customers.⁴⁴ SCE also presents energy burden calculations grouped by usage to evaluate the affordability impact on essential usage. The results indicate that from 2019-2023, low usage households (usage from 0 to 299 kilowatt hour (kWh)/month) will see an increase in energy burden of about 0.5 percent (an increase from 1.6 percent to 2.2 percent for CARE customers and an increase from 1.4 percent to 1.9 percent for non-CARE customers).⁴⁵

Finally, SCE presents the hours at minimum wage (HMW) metric. SCE presents 2016 data showing that California has, on average, one of the lowest HMW values in the country, with SCE's HMW being slightly lower than the California average.⁴⁶ SCE's testimony indicates that while the average SCE residential bill is expected to increase from \$107 in 2019 to \$150 in 2023, the minimum wage is expected to increase from \$11 to \$15 per hour over the same time period, increasing the HWM by 0.2 hours.⁴⁷

⁴³ *Id.* at 5.

⁴⁴ *Id.* at 12, Table II-1.

⁴⁵ *Id.* at 14, Table II-2.

⁴⁶ *Id.* at 16, Figure II-8.

⁴⁷ *Id.* at 16-17.

6.1.2. TURN's Critiques of SCE's Metrics

TURN argues that SCE's GRC request is far from affordable given that SCE is requesting a 20.5 percent increase over 2019 authorized GRC base rates for TY 2021, as well as attrition year increases of more than \$385 million and \$538 million in 2022 and 2023, respectively.⁴⁸ TURN points out that SCE's request will result in large bill increases (\$300/year for non-CARE customers and \$200/year for CARE customers by 2023); that many Californians already have trouble paying all of their essential expenses; and that the current economic downturn will exacerbate the affordability crisis.⁴⁹

TURN notes that the rise in SCE rates and bills have outstripped the growth in Californians' incomes, especially among lower income households. SCE points out that from 2009 to 2019, its SAR increased 12 percent and CPI increased 19 percent. However, the average cost of bills at baseline residential usage (including CARE customers) over the same period increased by 48 percent.⁵⁰ Moreover, from 2009 to 2018, the real median household income in California increased approximately 7 percent, with wages at the highest end of the scale increasing much faster than wages for lower paid workers.⁵¹

TURN estimates that in 2018, more than 1.5 million residential customers in SCE's service territory had income levels below the levels needed to achieve a modest, but adequate standard of living (as measured by the California Family

⁴⁸ Ex. TURN-03-E at 1. These numbers reflect SCE's requests as set forth in its Amended Application.

⁴⁹ *Id.* at 2-3.

⁵⁰ *Id.* at 9.

⁵¹ *Id.* at 9-10.

Needs Calculator, formerly called the Self-Sufficiency Standard (SSS)).⁵² TURN also presents data showing that approximately two-thirds of SCE's customers reside in counties where there is a gap between SSS and the income thresholds for the CARE, Family Electric Rate Assistance (FERA), and Energy Savings Assistance (ESA) assistance programs.⁵³

TURN critiques SCE's energy burden calculations, noting that SCE compares the cost of SCE bills to pre-tax (rather than after-tax) household income, thus ignoring the costs of housing, taxes, food, and other necessities.⁵⁴ TURN also observes that by SCE's own calculations, the average energy burden for a non-CARE customer will increase 43 percent increase as a percent of income between 2019 and 2023, and that an energy burden of 4.1 percent for CARE customers who have smaller household budgets will crowd out other necessities and force untenable choices for economically disadvantaged families.⁵⁵

Lastly, TURN discusses SCE's disconnection rates and notes that SCE has historically disconnected a larger percentage of customers eligible for disconnection than the other IOUs, and that disconnection rates are likely a function of electric rates and bills.

6.1.3. Discussion

The issue of the affordability of utility services has been a longstanding priority and concern for the Commission. As noted by several parties, and as discussed further above, these concerns are particularly acute at this time given

⁵² *Id.* at 14.

⁵³ *Id.* at 14-15.

⁵⁴ *Id.* at 3.

⁵⁵ *Ibid.*

the economic uncertainties and additional stresses facing Californians due to the impacts of the COVID-19 pandemic.

In Rulemaking (R.) 18-07-006 (the Affordability Rulemaking), the Commission instituted a rulemaking to develop a common understanding and methods and processes to assess, consistent with Commission jurisdiction, the impacts on affordability of individual Commission proceedings and utility rate requests. In a decision issued in that Rulemaking (D.20-07-032), the Commission defined affordability as “the degree to which a representative household is able to pay for an essential utility service charge, given its socioeconomic status.”⁵⁶ The Commission also adopted metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential electricity, gas, water, and communications utility services in California.⁵⁷ The Commission’s work on how to implement these metrics in proceedings is ongoing and the subject of a subsequent phase of the rulemaking.⁵⁸

In D.20-07-032, the Commission did not adopt an absolute definition of affordability but emphasized the assessment of the relative impacts of affordability over time to aid the Commission in its decision-making as it evaluates utilities’ requests with rate implications. Although there are no established thresholds as to when a rate becomes unaffordable, it is undisputable that SCE’s requested revenue increase would result in rates that are relatively more unaffordable than in the recent past. SCE’s requested revenue requirement

⁵⁶ D.20-07-032 at 9.

⁵⁷ The adopted metrics are: (1) the hours at minimum wage required to pay for essential utility services; (2) the vulnerability index of various communities in California; and (3) the ratio of essential utility service charges to non-disposable household income – known as the affordability ratio. (*Id.* at 2.)

⁵⁸ *Id.* at 68-69.

increase of approximately 20 percent would be a substantial increase for customers to absorb at one time. SCE presents metrics that include cost recovery requests in other proceedings, but the projected 20 percent rate increase is based on its requests in Track 1 of this proceeding alone, and does not take into account pending and approved rate requests in this and other proceedings.

SCE presents data that its SAR has risen slower than inflation and the SARs of other IOUs. However, TURN presents evidence that household incomes for Californians, particularly low-income Californians, have not kept pace with inflation or the rise in SCE's rates and bills. TURN also presents evidence that segments of the population are already struggling to pay bills for essential expenses, including segments of the population that are below income thresholds for a family to achieve a modest but adequate standard of living but not eligible for utility assistance programs.⁵⁹ These sentiments were also shared by many members of the public both at the PPHs and in written public comments submitted to the Commission.

Some of these affordability issues are outside the scope of this proceeding (*e.g.*, eligibility thresholds for CARE/FERA, disconnection policies, consumer

⁵⁹ SCE argues that TURN cherry-picks Self-Sufficiency Standard (SSS) data for the purposes of its analysis by choosing a four-person family that includes two adults, one preschool child, and one school-age child. SCE observes that changing the household composition to two adults and two teenagers, for example, would result in the SSS annual wage dropping below the CARE and FERA income limits for all of the counties within SCE's service territory. (SCE OB at 13.) SCE also observes that even using TURN's chosen demographics for a family of four, TURN's testimony still shows that in the majority of the counties listed, such households earning the SSS annual wage would be eligible for SCE's FERA assistance program. (*Ibid.*) Although SCE's observations may be accurate, these observations do not invalidate TURN's data and analysis for the segment of the population with TURN's selected household composition. Moreover, approximately two-thirds of SCE's customers reside in the counties TURN identifies as having FERA income gaps because they include the two most populous counties within SCE's service territory, Los Angeles and Orange. (Ex. TURN-03-E at 15, Figure III-4.)

protections due to COVID-19) and are being actively examined in other proceedings. Moreover, we recognize that affordability issues are also largely driven by factors other than electric bills, such as languishing wages, unemployment rates, and costs of housing and other essential utility and non-utility expenses. However, we find the data and analysis presented by the parties to be a useful backdrop against which to evaluate SCE's requests in this proceeding.

We are more cognizant than ever of the need to limit rate increases to the extent possible to ensure affordable rates. At the same time, we are mindful that it is also in the public interest to ensure that the utility has adequate funding to safely operate and maintain its infrastructure and make necessary investments in safety and reliability. Many of SCE's requests were vigorously litigated by the parties, creating a robust record, which has aided the Commission's review of SCE's requests. We have carefully reviewed the record and deny or adjust downward several of SCE's requests that we find are not adequately justified that would not result in just and reasonable rates.

6.2. Disconnections Compliance Report

Section 718(b) directs the Commission to consider the impact of any proposed increase in rates on disconnections for nonpayment and to incorporate a metric for residential nonpayment disconnections in each energy utility's general rate case proceeding. In order to comply with this requirement, the Commission in SCE's 2018 GRC directed SCE to develop a report, to be included

as part of its next GRC, that analyzes the relationship between rate increases, arrearages, and disconnections, if any.⁶⁰

Pursuant to the Commission's direction, SCE presented testimony in this proceeding analyzing the relationship between rate and bill increases and residential customer disconnections and arrearages.⁶¹ SCE performed regression analyses of disconnections and arrearages data using inflation-adjusted monthly rates and bills from January 2014 through December 2019. Based on these analyses, SCE draws the conclusion that there is no meaningful relationship between electric rates or bills, and the number of residential disconnections or amount of monthly arrearages.⁶² SCE instead finds that changes in disconnections and arrearages are better explained by monthly and seasonal fluctuations, as well as the increase in the overall number of SCE's residential customers.⁶³ SCE's analyses also found that rates and bills have decreased during the period 2014 through 2019 on a real dollar basis, indicating that inflation has outpaced increases in rates and bills.⁶⁴

TURN argues that SCE's finding of no meaningful relationship between increases in SCE's average rates or bills and the number of residential disconnections or dollar amount of monthly arrearages over time is not credible and should be rejected. TURN argues that SCE's regression analyses are flawed because: (1) SCE uses inflation-adjusted rather than nominal rates and bills; and

⁶⁰ D.19-05-020 at 22. The Commission did not implement Section 718 in SCE's 2018 GRC decision because this statute was added to the Public Utilities Code during the pendency of SCE's 2018 GRC. (*Id.* at 21.)

⁶¹ Ex. SCE-07, Vol. 5.

⁶² *Id.*, Appendix A at 19.

⁶³ *Ibid.*

⁶⁴ *Ibid.*

(2) SCE uses multiple explanatory variables related to bills and rates, which are likely strongly correlated to each other, in the same regression model.⁶⁵ TURN argues that SCE's own analyses indicate a clear relationship between nominal rates and disconnections, which SCE fails to fully examine.⁶⁶ TURN performed its own preliminary regression analysis using annual disconnections data, which showed a moderate relationship between annual disconnections and SCE's system average residential rates.⁶⁷ TURN also notes that SCE's conclusions are inconsistent with the results of PG&E's SB 598 disconnections analysis performed in PG&E's 2020 GRC based on actual bill data, which found a strong correlation between monthly bills and disconnections.⁶⁸

We find that TURN raises valid criticisms of SCE's analyses. It is appropriate for changes in purchasing power to be accounted for when comparing rates or bills over a multi-year period. However, evidence in this proceeding suggests that CPI may not accurately capture changes in purchasing power, particularly for lower income households, because household incomes have not increased at the same pace as CPI.⁶⁹ In light of these considerations, and in the absence of better data in the record regarding changes in household income, we do not rule out the possibility that nominal rates and bills would better represent low-income households' income growth compared to CPI-adjusted rates and bills. We also agree that SCE's use of multiple predictive

⁶⁵ Ex. TURN-03-E at 25.

⁶⁶ *Id.* at 22-23.

⁶⁷ *Id.* at 24.

⁶⁸ *Ibid.* SCE disputes TURN's characterization of the conclusions from PG&E's regression analyses. (Ex. SCE-18, Vol. 5 at 9-10.)

⁶⁹ Ex. TURN-03-E at 9-10.

variables may distort the regression analysis and that it is more appropriate for rate and bill variables to be separately considered.

Ultimately, we do not rely on SCE's analyses to determine the impact that its proposed rates will have on disconnections for nonpayment during this GRC cycle. The Commission has adopted consumer protections, which will limit disconnections and ensure that the rate increase we adopt today does not lead to an increase in disconnections. Therefore, we find that SCE's analyses of its historical disconnections data (based on periods when such consumer protections were not in effect) are not indicative of the impact that SCE's rates will have on disconnections for nonpayment during this GRC period.

The Commission is considering issues related to customer disconnections resulting from nonpayment across the regulated utilities in R.18-07-005 (Disconnections Rulemaking). In the Phase I decision, D.20-06-003, the Commission adopted an annual cap on the percentage of residential customer accounts that SCE can disconnect from utility service at seven percent for 2021, six percent for 2022, five percent for 2023, and 4 percent for 2024.⁷⁰ The decision also places other limits and conditions on residential disconnections for nonpayment.⁷¹ We use the caps adopted in D.20-06-003 as the metric for residential nonpayment disconnections required pursuant to Section 718(b).

In order for the Commission to comply with Section 718's requirements in SCE's next GRC, SCE shall include in its next GRC filing a report on the number and percentage of residential utility disconnections and amount of arrearages during this GRC cycle, and an analysis of the impacts that any proposed rate

⁷⁰ D.20-06-003 at Ordering Paragraph (OP) 1(a).

⁷¹ *Id.* at OP 1.

increases would have on disconnections and arrearages. SCE's report shall: (1) reflect consideration of approaches other than CPI to capture changes in purchasing power, such as use of nominal bills and rates (*e.g.*, if there are minimal changes) or household income levels; and (2) present analyses based solely on bill variables. SCE is also not precluded from presenting any additional analyses of its choosing. We would expect that rates would have limited, if any, meaningful relationship to disconnections so long as there are policies and caps in effect limiting disconnections such as those adopted in D.20-06-003 and Resolution E-4842 (which adopted a moratorium on utility disconnections because of the COVID-19 pandemic).

7. Risk-Informed Strategy and Business Plan

One of the central tasks in this proceeding is to balance safety and reliability risks with the associated cost to mitigate those risks. SCE is required by law to "promote the safety, health, comfort, and convenience of its patrons, employees, and the public" while including only "just and reasonable" charges in its rates.⁷² A fundamental challenge in many disputed areas of this case is to reach an outcome consistent with these two, often competing, objectives. This is a familiar challenge present in numerous previous GRCs and other Commission proceedings, even though the approach, framework, and language surrounding the issues continues to evolve.

In D.14-12-025, the Commission adopted a new risk-based decision-making framework for future GRCs to "assist the utilities, interested parties and the Commission, in evaluating the various proposals that the energy utilities use for assessing their safety risks, and to manage, mitigate, and minimize such

⁷² Section 451.

risks.”⁷³ For the large energy IOUs, this takes place through two procedures: (1) the filing of a Safety Model Assessment Proceeding (S-MAP), and (2) a subsequent Risk Assessment Mitigation Phase (RAMP) submission. The RAMP submission is required to be integrated with a utility’s GRC filing, and provides an assessment of the utility's top safety risks, as well as how the utility plans to manage, mitigate, and minimize those risks through its GRC funding requests.⁷⁴

SCE filed its RAMP Report on November 15, 2018 in Investigation (I.) 18-11-006 (RAMP Report), and subsequently integrated the RAMP Report findings with its 2021 GRC Application and testimony.⁷⁵ The RAMP Report examined and prioritized safety risks to SCE's customers, employees, contractors, and the company as a whole. The following top nine safety risks were identified through SCE's RAMP Report: (1) building safety; (2) contact with energized equipment; (3) cyberattack; (4) employee, contractor, and public safety; (5) hydro asset safety; (6) physical security; (7) wildfire; (8) underground equipment failure; and (9) climate change. SCE then conducted a statistical risk assessment to evaluate the anticipated risk reduction of potential new mitigation measures,⁷⁶ and calculated the Risk Spend Efficiency (RSE), or the measure of risk reduction benefit per dollar spent.⁷⁷

In this GRC, SCE proposes programs and investments that correspond to the controls identified in SCE’s RAMP Report to mitigate the top nine safety risks. Throughout its direct testimony supporting GRC funding requests, SCE

⁷³ D.14-12-025 at 4.

⁷⁴ *Id.* at 38.

⁷⁵ D.20-10-004 at 15; also, Ex. SCE-01, Vol. 2.

⁷⁶ Ex. SCE-01, Vol. 2 at 9-10.

⁷⁷ Ex. SCE-01, Vol. 2 WP at 3.

indicates whether the work performed relates to a control or mitigation as described in SCE's RAMP Report and provides a comparison between what SCE estimated in its 2018 RAMP Report and what is forecasted in this GRC.

Significant differences between SCE's 2018 RAMP Report and its GRC request are noted within relevant safety-related sections of this decision.

In some cases, SCE has shifted resources from traditional infrastructure programs to perform work on wildfire mitigations, with the most substantial increase being to SCE's proposed wildfire covered conductor program. SCE evaluated the safety trade-off associated with shifting additional funding to wildfire mitigation programs, as well as a more focused analysis on the Wildfire Covered Conductor program, and determined the safety reduction gained through proposed wildfire mitigation activities exceeds the associated benefit reduction in other RAMP risk initiatives.⁷⁸

In addition to the enterprise-wide risk analysis, SCE also conducted a wildfire risk analysis to identify high-risk fire areas within its service territory and to target the deployment of resources and programs addressing SCE's wildfire risk (Wildfire Risk Model). The Wildfire Risk Model applies ignition probability and fire propagation to circuits in SCE's High Fire Risk Areas (HFRA) and builds upon SCE's 2018 RAMP Report; the fire ignition and mitigation mapping work conducted as part of SCE's Grid Safety and Resiliency Program (A.18-09-002); SCE's 2019 WMP; and more recent consulting work by Reax Engineering to develop a fire-propagation model in SCE's HFRA. The output of

⁷⁸ Ex. SCE-12, Vol. 02 at 10-11.

the Wildfire Risk Model is a risk score that identifies potential high-risk circuits and segments where additional mitigations may be considered.⁷⁹

Cal Advocates provides two recommendations for SCE's next RAMP and GRC filings: first, Cal Advocates recommends SCE clearly identify and quantify key constraints associated with SCE's selection of its risk mitigation programs, as well as how constraints impacted SCE's choice of risk mitigation activities.⁸⁰ Second, Cal Advocates recommends SCE consider more realistic alternative mitigation plans during the next RAMP phase, pointing specifically to SCE's inclusion of an alternative mitigation plan for hydro risk asset safety involving the relocation or purchase of private properties within potential inundation zones.⁸¹

In response, SCE states that Commission's more recent S-MAP decision, D.18-12-014, directed more quantified risk mitigation to be the subject of further consideration in a subsequent rulemaking, rendering Cal Advocates' recommendation premature. Further, SCE states that developing additional project management charts for each of the more than 40 RAMP controls and mitigations would be overly burdensome, while the usefulness of such material is unclear.⁸² SCE also asserts it included realistic alternatives in its RAMP filing, and that the single example Cal Advocates provides of what it considers an unrealistic mitigation plan is a course of action SCE is currently pursuing to reduce risk at the Thompson Dam on Catalina Island.⁸³

⁷⁹ Ex. SCE-01, Vol. 2 at 18-24.

⁸⁰ Ex. PAO-14 at 3-5.

⁸¹ *Id.* at 5-7.

⁸² Ex. SCE-12, Vol. 2 at 5-7.

⁸³ *Id.* at 8.

TURN provides four recommendations largely related to SCE's Wildfire Risk Model: First, TURN recommends SCE address issues of affordability and cost-effectiveness in subsequent RAMP and GRC analyses. TURN asserts that SCE did not provide RSEs for all proposed mitigation programs in this GRC, nor did SCE tailor the covered conductor proposal using the risk profile of each of its circuits, undermining SCE's arguments that the proposals are cost-efficient and affordable.⁸⁴

Second, TURN notes that SCE uses a "top-down" system-wide risk modeling approach in its RAMP Report, and a "bottoms-up" approach to inform its Wildfire Risk Model. TURN asserts the different approaches result in different levels of projected risk reduction from deployed mitigation measures, and recommends the two analyses either use the same approach or be validated against each other to ensure verifiable risk modeling.⁸⁵

Third, TURN recommends the probability of ignition calculation in SCE's Wildfire Risk Model be performed over a specific period of time, rather than using a timeless unconditional probability calculation,⁸⁶ consistent with the S-MAP settlement approved in D.18-12-024.⁸⁷ TURN asserts that using an undefined point in time cannot properly reflect a likelihood of ignition in varying wet, dry, or windy weather conditions.⁸⁸

⁸⁴ TURN OB at 24.

⁸⁵ *Id.* at 25. Also, Ex. TURN-02 at 32-33.

⁸⁶ A timeless unconditional probability is unaffected by preceding or future occurrence of other events, and is not limited to a specific time period. (*See* SCE-12, Vol. 02 at 12).

⁸⁷ TURN OB at 26.

⁸⁸ Ex. TURN 02 at 35.

Fourth, TURN recommends SCE include egress in its calculation of risk consequence in order to help target certain mitigations, such as undergrounding, in areas with less ability to quickly evacuate in a fire.⁸⁹

In response to TURN's recommendations, SCE asserts it took safety and affordability considerations into account when developing its GRC forecasts, but that it will consider, for its next GRC, whether a more specific discussion of affordability should also be included within the Risk-Informed Decision Making and Strategy testimony. Although SCE provides direct responses to TURN's other recommendations,⁹⁰ as a general matter SCE asserts that R.20-07-013, the Commission's Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities, is a more appropriate venue to address the merits of TURN's proposals.⁹¹

Finally, SCE argues RSEs should not be the only factor used when developing a prudent risk mitigation plan., It contends narrow and exclusive focus on cost efficiency would be inconsistent with the statutory directive that a utility "shall construct, maintain, and operating its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."⁹²

⁸⁹ *Ibid.*

⁹⁰ Including arguments that a timeless unconditional probability is both consistent with the S-MAP settlement agreement and more representative of actual ignition probability (*See Ex. SCE-12, Vol. 2 at 12-13*), and that SCE will seek future opportunities to improve the consistency of the "top-down" and "bottoms-up" modeling approaches and incorporate egress into the risk modeling (*See Ex. SCE-12, Vol. 2 at 10 and 14*).

⁹¹ SCE RB at 13-14.

⁹² Cal. Pub. Util. Code § 8386(a).

In many ways, SCE's 2021 GRC application is a major advancement in the development of a risk-based decision-making framework envisioned in D.14-12-025. This is the first time a large IOU in California performed statistical risk assessment to evaluate company-wide risks and the effectiveness of proposed controls and mitigations (through the RAMP process), and then integrated the findings and recommendations from the Commission's Safety and Policy Division on the RAMP Report throughout its GRC application. In addition, SCE incorporated into its GRC filing a risk-based approach to identify high-risk wildfire areas within its service territory, enabling the Commission and intervenors to better understand how SCE identified and prioritized its proposed wildfire mitigation measures. SCE's use of risk modeling to inform its GRC requests has enabled greater transparency and participation in this proceeding, increasing accountability for how safety risks are managed, mitigated and minimized.

We find that several of the recommendations provided by Cal Advocates and TURN would be better addressed through the S-MAP proceeding, and therefore defer consideration of these issues. This includes Cal Advocates' recommendation to quantify the key constraints associated with SCE's selection of risk mitigation programs, as well as TURN's recommendation to address issues of affordability in subsequent RAMP and GRC analyses. Both recommendations involve broader, potentially significant, changes to the risk framework that we believe would benefit from consistent treatment across the large IOUs. In addition, we defer consideration of TURN's recommendation to use a specific timeframe for the probability of ignition calculation, which

involves clarifications to D.18-12-014 currently being considered in Track 1 of R.20-07-013.⁹³

While we agree that SCE should include realistic alternative mitigation plans in future RAMP reports, we find SCE provided reasonable justification for the inclusion of its hydro risk asset alternative mitigation plan in the 2018 RAMP Report. SCE is encouraged to coordinate with Cal Advocates regarding the inclusion of alternative mitigation plans for SCE's hydro risk assets in the development of future RAMP submissions.

TURN's recommendation to require SCE to validate the results of its "top-down" and "bottoms-up" risk modeling approaches against each other, explaining any divergence between the results and how the model results support proposed mitigation programs, is well taken. While we appreciate the models serve different purposes, to the extent different models are used to evaluate the same risk and associated impact of various mitigation measures, SCE should include a qualitative explanation for any divergence between the model results and how the results support the proposed mitigations programs. Similarly, TURN's recommendation to include egress in the calculation of wildfire risk consequence would improve SCE's risk management approach, and is generally uncontested. To the extent this issue is not addressed in R.20-07-013, we direct SCE to incorporate egress, and other conditional risks as appropriate, in future RAMP and GRC risk modeling.

Regarding the use of RSEs, the S-MAP settlement (D.18-12-014) provides that utilities are to provide a ranking of proposed mitigations by RSE as part of

⁹³ See November 2, 2020 Assigned Commissioner's Scoping Memo and Ruling in R.20-07-013.

their GRC submission.⁹⁴ As a general matter, RSEs provide a useful point of comparison regarding the cost-effectiveness of proposed mitigations belonging to the same risk tranche and, with the exception of Public Safety Power Shutoff (PSPS)⁹⁵ the default should always be for a utility to provide RSE calculations for its proposed mitigations. For SCE's proposed wildfire covered conductor program, this includes the presentation of RSE calculations at the circuit level. This direction is consistent with the Commission's Resolutions adopting the 2020 WMPs, which found that "RSE calculations are critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds,"⁹⁶ and that SCE's "2020 WMP is lacking in this regard."⁹⁷ While we are cognizant that RSEs are not the only factor in the development and consideration of a prudent risk mitigation plan (which may be influenced by other factors, such as labor resources, technology, compliance requirements, planning and construction lead time, etc.), it is SCE's responsibility to clearly and transparently explain its rationale for selecting the type and scale of risk mitigations, including how RSE calculations were considered.

8. Distribution Grid

8.1. Infrastructure Replacement

8.1.1. Capital Budget

Distribution Infrastructure Replacement (DIR) work includes the capital expenditures that SCE incurs to replace distribution grid infrastructure such as

⁹⁴ D.18-12-014, Attachment A at A-14.

⁹⁵ As noted in Resolution WSD-002, RSE is not an appropriate tool for justifying the use of PSPS. (See WSD-002 at 20.)

⁹⁶ Resolution WSD-002 at 20.

⁹⁷ Resolution WSD-004 at 27.

transformers, switches, capacitors, automatic reclosers, underground structures, cables, and conductors. DIR includes infrastructure component replacements that are planned based on engineering and data analysis.⁹⁸ Infrastructure component replacements that are unplanned for in-service failures or planned based on inspections are included as part of Distribution Preventative and Breakdown Capital Maintenance activities, discussed in a separate section, below.

There are ten different activities that make up the DIR program with each activity falling into one of three categories:⁹⁹

- (1) Underground infrastructure which includes five activities:
(A) the Worst Circuit Rehabilitation program, (B) Cable-In-Conduit Replacement program, (C) Underground Switch Replacement program, (D) Underground Structure Replacement program, and the (E) Cable Life Extension program.
- (2) Overhead infrastructure which includes one activity: The Overhead Conductor Program (OCP).
- (3) Infrastructure that exists in both overhead and underground configurations which includes four activities:
(A) Capacitor Bank Replacement program, (B) Distribution Automatic Recloser Replacement program, (C) 4 kilovolt (kV) Cutover and 4 kV Substation Elimination programs, and (D) the Polychlorinated Biphenyls (PCB) contaminated Transformer Removal program.

SCE requests total capital expenditures of \$638.521 million for 2019 recorded and 2020-2021 forecast DIR activities.¹⁰⁰

⁹⁸ Ex. SCE-02, Vol. 1, Pt. 1 at 4.

⁹⁹ *Id.* at 16.

¹⁰⁰ Ex. SCE-13, Vol. 1, Pt. 1 at 2-4.

SCE has significantly reduced many of its DIR forecasts from the RAMP forecast levels to help ensure adequate resources to address wildfire risks and the need for grid resiliency activities during this GRC cycle. SCE's "unconstrained need" for DIR for 2019-2023, as identified in its RAMP report, is \$2.282 billion. In comparison, SCE's GRC forecast for 2019-2023 is \$858 million, \$1.424 billion less than the "unconstrained need" amount.¹⁰¹ SCE explains that there are not enough available resources to cost-effectively implement the scope of both Grid Hardening and DIR at the levels that SCE would otherwise propose.¹⁰² According to a risk analysis conducted by SCE, "the safety reduction *gained* through the enhanced portfolio of wildfire mitigations *exceeds* the safety reduction *lost* in other risk initiatives in RAMP."¹⁰³

SCE explains that the near-term deferments in DIR activities do not mean that the problems with aging infrastructure have changed, and thus, may cause an increase in the average age of distribution infrastructure and in-service failure rates. SCE states the reductions should be considered temporary in nature and as wildfire prevention-related work nears completion SCE expects to increase DIR activities to compensate for the longer-term effects of the near-term deferments.¹⁰⁴

SCE's DIR forecasts are unopposed. CUE, however, argues that if the Commission reduces SCE's request for wildfire management capital spending, all such dollars should be reassigned to address deferred DIR programs.¹⁰⁵ CUE

¹⁰¹ Ex. SCE-02, Vol. 1, Pt. 1 at 14, Table II-3.

¹⁰² *Id.* at 14.

¹⁰³ Ex. SCE-01, Vol. 2 at 25.

¹⁰⁴ Ex. SCE-02, Vol. 1, Pt. 1 at 14.

¹⁰⁵ CUE OB at 11-12.

argues that deferring necessary safety and reliability work results in intergenerational inequity by requiring future ratepayers to be responsible for the costs of the work deferred in this GRC, as well as to experience degraded safety and reliability due to infrastructure not being replaced in a timely manner.

As discussed in the Wildfire Management Section (Section 17), we do not approve the full capital funding requested by SCE for wildfire management activities. However, we do not find that the record supports the authorization of DIR capital expenditures beyond those requested by SCE. No party has made specific proposals for increasing any of the DIR budgets. We decline to approve funding in excess of SCE's requested DIR budgets absent a specific plan as to where the additional funding would be spent.¹⁰⁶

CUE asserts that SCE has deferred \$1.424 billion of necessary DIR work based on SCE's identification of its "unconstrained need" in its RAMP Report. SCE defines "unconstrained need" as "the estimated amount that SCE would have otherwise requested in this GRC, if not for wildfire risk mitigation efforts."¹⁰⁷ SCE has not presented the "unconstrained need" amount for Commission review or approval. There has been no finding that this amount is reasonable or necessary during this GRC cycle for the provision of safe and reliable service. Moreover, in considering the amount of funding to authorize, the Commission must balance safety and reliability with affordability and reasonable rates.

¹⁰⁶ It is possible that SCE may redirect any additional DIR funding to wildfire mitigation programs. However, in this decision we approve the wildfire mitigation cost forecasts that we find to be reasonable, and SCE has several mechanisms for seeking future recovery of wildfire mitigation costs in excess of those authorized in this GRC.

¹⁰⁷ Ex. SCE-13, Vol. 1, Pt. 1 at 1, fn. 2.

Therefore, we find reasonable and approve SCE's requested capital expenditures of \$638.521 million for 2019 recorded and 2020-2021 forecast DIR activities. Furthermore, although we do not find that the record supports any increase to SCE's requested DIR budgets, we find that a two-way balancing account should be established for the Underground Structure Replacement program.

SCE contends that its requested DIR capital expenditures will enable SCE "to continue providing safe and reliable power to customers."¹⁰⁸ No party has identified any safety-critical asset replacements that would be deferred due to SCE's planned DIR deferrals for this GRC cycle.¹⁰⁹ We find, however, that the record is not clear whether SCE's requested expenditures for the Underground Structure Replacement program are sufficient to address critical safety risks that should be addressed during this GRC cycle.

We find that the following work for the Underground Structure Replacement program should not be deferred during this GRC cycle:

- Underground structure replacements that are classified as Grade F (at risk of failing with expected remaining life of 1-5 years) with either Code E (emergency, recommend replacing as soon as possible) or Code 1 (recommend replacing within the next 3 years) and rated very high or high in population proximity, population density, traffic rate, and falling debris hazard cannot be deferred and must be replaced within this GRC cycle.¹¹⁰

¹⁰⁸ SCE OB at 28.

¹⁰⁹ See TURN RB at 6.

¹¹⁰ Grading and coding are based on the American Society of Civil Engineers (ASCE) infrastructure report card system. (Ex. SCE-02, Vol. 1, Pt. 1 at 56.) SCE also uses a four-tier rating system to prioritize scheduling the replacement of structures based on population proximity, population density, traffic rate, and falling debris hazard. (*Id.* at 63.)

- Underground structures that are classified as Grade D (Poor, with a remaining life of 5-15 years) but with a Code 2 (recommend installing shoring within the next 3 years) and rated very high or high in population proximity, population density, traffic rate, and falling debris hazard cannot be deferred and must install shoring within this GRC cycle.

SCE forecasts replacement of 108 structures and shoring of 135 structures between 2019-2023.¹¹¹ During evidentiary hearings, SCE's witness indicated that work on some underground structures classified as Grade D or F would be deferred during this GRC cycle.¹¹² It is unclear from the record whether SCE's planned deferrals would include any underground structures graded D or F with the codes and ratings described above. However, we do not find it reasonable for this work to be deferred. Given the lack of clarity in the record regarding the number of underground structures that would fall into these categories and the associated costs for the necessary work, we authorize SCE to establish a two-way balancing account for this GRC cycle to track expenditures for the necessary underground structure replacement and shoring work described above.

8.1.2. Proposal for Ten-Year Infrastructure Replacement Plan

CUE does not oppose SCE's focus on wildfire prevention work for this GRC cycle given its current resource constraints.¹¹³ However, CUE raises concerns regarding SCE's deferral of DIR work. CUE states that while SCE considers reductions to the DIR budgets to be temporary, SCE did not analyze the timing or magnitude of any future increases to the DIR programs to make up

¹¹¹ *Id.* at 61, Tables II-20 and II-21.

¹¹² RT, Vol. 3 at 423.

¹¹³ CUE OB at 3.

the deferred work, or the long-term safety and reliability impacts from deferring this work.¹¹⁴ To address these concerns, CUE recommends the Commission require SCE to prepare an infrastructure replacement plan as part of each GRC that includes three elements: (1) how SCE will achieve steady-state replacement of aging infrastructure; (2) a ten-year forward infrastructure replacement plan; and (3) a discussion of potential resource constraints, including personnel constraints, and how SCE will address them.¹¹⁵

SCE argues that its five-year IR planning process is sufficient for the purpose of prioritizing both near-term and longer-term IR activities.¹¹⁶ SCE notes that it updates its five-year plan on an annual, rolling basis. SCE also notes that the five-year planning horizon is consistent with the scope of the RAMP, which is intended to inform the GRC forecast. SCE argues that requiring an analysis with a different planning horizon would be highly disruptive and counterproductive to the overall intent of the RAMP.¹¹⁷

SCE also argues that attempting to calculate a steady-state replacement rate for IR planning purposes is fundamentally a “practical impossibility” given the inherent uncertainties in forecasting a distribution asset’s lifespan and would not provide meaningful information.¹¹⁸ SCE contends that factors such as non-fixed populations, non-like-for-like replacements, and environmental factors constantly disrupt the system trajectory towards steady-state and are difficult to

¹¹⁴ *Id.* at 6.

¹¹⁵ *Id.* at 7-8.

¹¹⁶ SCE OB at 29.

¹¹⁷ *Id.* at 30.

¹¹⁸ *Id.* at 30-31.

forecast.¹¹⁹ SCE argues that even if a steady-state rate could be calculated, using the rate to develop IR targets would not appropriately consider all failure-related risks because it would only focus on failure rate and ignore the failure impact.¹²⁰ SCE notes that assets with high-impact in-service failures could present a greater risk than assets with low-impact in-service failures.

Finally, SCE argues that a continuing requirement that SCE discuss DIR resource constraints is unnecessary, as SCE has already indicated that the DIR deferments are temporary. SCE states that, to the extent that resource constraints may impact SCE's future DIR plans, SCE will inform the Commission and other stakeholders as it did in this GRC.

We do not find the additional IR planning requirements proposed by CUE to be warranted. We agree with SCE that a steady-state replacement plan is not likely to provide meaningful information for setting appropriate IR targets due to the difficulties in forecasting when steady-state can be achieved and the lack of consideration of the impact of an in-service failure. We find that a prudent asset replacement plan should be driven by consideration of not only failure rates but also failure consequences. As observed by TURN, "[i]t may be appropriate to preemptively replace assets whose failure has significant safety or reliability consequences, but it may be appropriate to let some assets 'run-to-failure' and replace them as needed."¹²¹

We also do not find justification for requiring a ten-year DIR planning horizon. We find SCE's existing five-year planning horizon, which is updated on an annual rolling basis, to be sufficient for near-term and longer-term DIR

¹¹⁹ Ex. SCE-13, Vol. 1, Pt. 1 at 6.

¹²⁰ *Id.* at 6-7.

¹²¹ TURN RB at 7.

planning. Adopting a planning horizon that is inconsistent with the RAMP detracts from the RAMP process and creates additional work for SCE, intervenors, and the Commission without necessarily yielding additional benefits due to the increase in uncertainties and unknown variables as the planning horizon is extended.

In future GRCs, SCE is expected to continue to provide adequate justification for its DIR plan and DIR forecasts, and provide details such as risk assessments and resource constraints that may impact the plan and forecasts. The Commission will review the information provided and authorize plans and forecasts that it finds to be consistent with the provision of safe and reliable service balanced with other considerations such as affordability and just and reasonable rates.

8.2. Inspections and Maintenance

8.2.1. Inspections and Maintenance O&M

Distribution Inspections and Maintenance activities are performed on SCE's distribution lines and equipment located outside of a substation. SCE performs most of the work to satisfy safety maintenance and inspections requirements to help mitigate the safety and reliability impacts associated with equipment failure throughout SCE's distribution system.

SCE forecasts TY O&M expenses of \$163.828 million for Distribution Inspections and Maintenance.¹²² This forecast includes funding for the following activities:¹²³

¹²² Ex. SCE-13, Vol. 1, Pt. 2E at 2, Table I-1; Ex. SCE-52A2E2, Appendix C at C9. This forecast reflects reductions SCE made in Update Testimony to exclude amounts for assisting or deterring union organizing, which SCE is required to exclude from rates pursuant to AB 560.

¹²³ Ex. SCE-13, Vol. 1, Pt. 2E at 2, Table I-1; Ex. SCE-52A2E2, Appendix C at C9. These forecasts include SCE's AB 560 reductions.

Activity	TY Forecast (\$000)
Distribution Overhead Detailed Inspections	4,874
Distribution Preventive and Breakdown O&M Maintenance	107,239
Distribution Underground Detailed Inspections	6,158
Distribution Apparatus Inspection and Maintenance	5,697
Patrolling and Locating Trouble	21,878
Streetlight Operations, Inspections, and Maintenance	6,575
Distribution Support Activities	11,407
Total	163,828

Cal Advocates recommends adjustments to SCE's forecasts for:

(1) Distribution Overhead Detailed Inspections, and (2) Distribution Preventative and Breakdown O&M Maintenance. Cal Advocates finds the remainder of SCE's O&M forecasts for Distribution Inspections and Maintenance activities to be comparable to historical expense levels and does not oppose them.¹²⁴

We find that SCE has provided adequate justification for the unopposed forecasts.¹²⁵ For the reasons discussed below, we find that SCE has also adequately justified its forecasts that are opposed by Cal Advocates. Therefore, we find reasonable and approve SCE's total TY O&M forecast of \$163.828 million for Distribution Inspections and Maintenance activities.

8.2.1.1. Distribution Overhead Detailed Inspections

SCE's Distribution Overhead Detailed Inspections (ODI) program involves grid patrols and overhead detailed inspections of overhead electrical facilities such as poles, capacitors, switches, transformers, conductors, guy wires, and risers. SCE's Wireless Technology Rate, which is an inspection related to third-

¹²⁴ Cal Advocates OB at 19.

¹²⁵ SCE describes in detail the activities and basis for its cost forecasts in Ex. SCE-02, Vol. 1, Pt. 2.

party attachments (e.g., cable television/internet and telecommunications) to distribution poles, is also included in this activity.

SCE forecasts \$4.874 million for its TY ODI O&M expenses.¹²⁶ SCE's forecast is based on 2018 recorded costs, excluding costs incurred by Enhanced Overhead Inspections (EOI) in HFRAs. If SCE's EOI program is not fully funded as requested, SCE proposes an alternate forecast of \$6.551 million based on 2018 recorded costs less one-time infrared inspections costs.¹²⁷

Cal Advocates recommends that the Commission deny SCE's request for funding of EOI and adopt SCE's alternate TY O&M forecast of \$6.551 million for ODI. Cal Advocates opposes SCE's funding request for EOI arguing that these same activities are already included in ODI.¹²⁸

As discussed further in the Wildfire Management Section (Section 17.9.1.2), we find that SCE has adequately justified its TY O&M forecast for the EOI program. SCE has demonstrated that its forecast EOI costs are distinguishable from and incremental to its forecast ODI costs. Because we approve SCE's requested O&M funding for EOI, we find it reasonable to adopt SCE's ODI forecast that excludes EOI costs. Therefore, we approve SCE's forecast of \$4.874 million for TY ODI O&M expense.

8.2.1.2. Distribution Preventative and Breakdown Maintenance

Distribution Preventative and Breakdown O&M Maintenance includes the costs to make repairs to distribution equipment identified through SCE's

¹²⁶ Ex. SCE-13, Vol. 1, Pt. 2E at 6; Ex. SCE-52A2E2, Appendix C at C9. This amount reflects SCE's AB 560 adjustments made in update testimony.

¹²⁷ Ex. SCE-13, Vol. 1, Pt. 2E at 6.

¹²⁸ Cal Advocates OB at 20-21.

Distribution Inspection and Maintenance Program (DIMP). Planned maintenance work, also referred to as preventative maintenance, include repairs to SCE's equipment recorded as Priority 2 and Priority 3 items under DIMP, primarily driven from inspection activities. Unplanned activities, also referred to as breakdown maintenance, include the repair of SCE equipment and structures identified as Priority 1 conditions that are damaged, compromised, or have failed in service.

SCE forecasts \$107.239 million in TY O&M expense for Distribution Preventative and Breakdown Maintenance.¹²⁹ SCE derives its forecast by: (1) calculating the four-year average of 2014 to 2017 recorded costs; (2) adding to the four-year average the costs to perform Priority 3 maintenance items required by recent changes to General Order (GO) 95;¹³⁰ and (3) reducing the forecast for work that will be performed under the EOI program.¹³¹ SCE then normalizes its forecast for ratemaking purposes for 2021 through 2023.¹³² SCE states that if its EOI program is not fully funded, SCE will need to restore funding to the four-year recorded average (2014-2017) plus the addition of the Priority 3 maintenance items.¹³³

Cal Advocates recommends a TY forecast of \$98.724 million based on a five-year average (2014-2018) of recorded costs.¹³⁴ Cal Advocates argues that

¹²⁹ Ex. SCE-13, Vol. 1, Pt. 2 at 10; Ex. SCE-52A2E2, Appendix C at C9. This amount reflects SCE's removal of AB 560 costs in update testimony.

¹³⁰ SCE forecasts \$9 million for 2021, \$18 million for 2022, and \$27 million for 2023 for this work. (Ex. SCE-02, Vol. 1E2, Pt. 2 at 20, Table II-6.)

¹³¹ Ex. SCE-02, Vol. 1, Pt. 2 at 19; Ex. SCE-02, Vol. 1E2, Pt. 2 at 20, Table II-6.

¹³² Ex. SCE-02, Vol. 1, Pt. 2 at 19; Ex. SCE-02, Vol. 1E2, Pt. 2 at 20, Table II-6.

¹³³ Ex. SCE-02, Vol. 1, Pt. 2 at 19.

¹³⁴ Cal Advocates OB at 21-22.

since SCE was able to complete all routine and ongoing maintenance work as scheduled for 2018, SCE's recorded 2018 expenses should be included in the TY calculation. Cal Advocates also argues that SCE has failed to substantiate its estimates for the proposed TY activities.

We find SCE's use of the recorded four-year average (2014-2017) to develop its TY forecast to be reasonable. SCE provides sufficient justification for excluding recorded 2018 costs from the forecast. SCE's 2018 recorded expense was unusually low due to a one-time temporary change in maintenance repair scheduling, which SCE implemented to redirect resources to EOI.¹³⁵ SCE's 2019 recorded costs confirm that 2018 was an anomalous year, with 2019 recorded costs increasing to \$121.761 million from \$78.215 million in 2018.¹³⁶ SCE explains that this increase in 2019 costs was due to planned maintenance deferred in 2018 being shifted and rescheduled to 2019.¹³⁷

Cal Advocates agrees that it is reasonable to exclude 2018 recorded costs and use a four-year average (2014-2017) to determine the Distribution Preventative and Breakdown Capital Maintenance forecast due to 2018 capital projects being rescheduled for 2019.¹³⁸ We find that the same rationale applies to the O&M forecast.

We also find SCE's adjustment to account for new requirements related to Priority 3 maintenance items to be reasonable. Rule 18 of GO 95 requires the correction of overhead utility facilities that pose a risk to safety or reliability, or otherwise do not comply with GO 95. In D.18-05-042, the Commission amended

¹³⁵ Ex. SCE-13, Vol. 1, Pt. 2 at 12.

¹³⁶ *Id.* at 13.

¹³⁷ *Ibid.*

¹³⁸ Ex. PAO-04 at 15.

Rule 18 to require utilities to correct Priority 3 maintenance items within 60 months, with specified exceptions.¹³⁹ Prior to D.18-05-042, there had been no deadline for utilities to correct Priority 3 maintenance items.

SCE argues that it requires additional funding to plan and schedule work to meet this new deadline. In a data request response dated January 22, 2020, SCE stated that it had identified approximately 1,000,000 Priority 3 maintenance items, with approximately 335,000 of these items being identified in the last five years.¹⁴⁰ SCE's work plan reflects a ramping up of remediation work, which SCE argues is to ensure that the work can be completed by the compliance deadline. Given the volume of work SCE has identified it must complete to comply with the new deadline, we find SCE's requested adjustment to account for Priority 3 remediation work to be reasonable.

As discussed in the Wildfire Management Section (Section 17.9.1.2), we approve SCE's TY O&M forecast for EOI. Therefore, we find reasonable and adopt SCE's TY forecast of \$107.239 million for Distribution Preventative and Breakdown Maintenance activities, which includes a reduction for EOI activities.

8.2.2. Inspections and Maintenance Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast Distribution Inspection and Maintenance capital expenditures (nominal, \$000):¹⁴¹

¹³⁹ D.18-05-042 at 2. A Priority Level 3 risk is defined as "any risk of low potential impact to safety and reliability." (*Ibid.*)

¹⁴⁰ Ex. SCE-13, Vol. 1, Pt. 2, Appendix A at A-9 to A-10.

¹⁴¹ *Id.* at 18, Table II-8.

Capital Expenditures	2019	2020	2021
Distribution Claim	41,848	42,157	43,498
Distribution Preventative and Breakdown Capital Maintenance	363,794	277,373	286,197
Streetlight Maintenance and Light Emitting Diode (LED) Conversions	52,895	48,619	50,342
Distribution Tools and Work Equipment	2,947	3,376	3,430
Distribution Transformers	102,432	98,244	105,243
Prefabrication	18,267	18,843	22,398
Total	582,183	488,612	511,108

SCE's 2019 recorded expenditures for all Distribution Inspection and Maintenance activities are unopposed.¹⁴² SCE's 2020-2021 forecasts for: (1) Streetlight Maintenance and LED Conversions, and (2) Distribution Tools and Work Equipment are also unopposed.¹⁴³ SCE provides adequate justification for these forecasts.¹⁴⁴ Therefore, we find reasonable and approve the 2019 recorded costs and the unopposed forecasts for 2020-2021. Cal Advocates recommends adjustments to the forecasts for the remainder of the activities, which are discussed below.

8.2.2.1. Distribution Claim

Distribution Claim includes the costs incurred by SCE to repair damage to the distribution system caused by another party. The most common cause of damage occurs when a vehicle collides with a distribution pole or other above ground equipment.

SCE forecasts capital expenditures of \$42.157 million for 2020 and \$43.498 million for 2021 based on a five-year average (2014-2018) of recorded

¹⁴² *Ibid.*

¹⁴³ *Ibid.*

¹⁴⁴ Ex. SCE-02, Vol. 1, Pt. 2 at 40 and 52; Ex. SCE-02, Vol. 1E2, Pt. 2 at 41.

expenditures.¹⁴⁵ SCE argues that a five-year average is appropriate because these costs are random and beyond the control of the utility.¹⁴⁶ SCE's Results of Operations (RO) model uses a 50 percent collectible factor to indicate that SCE expects that half of the repair costs will be paid by the parties that caused the damage.¹⁴⁷

Cal Advocates agrees that a five-year average is reasonable but recommends basing the forecast on the average for 2015 through 2019. Cal Advocates' recommendation results in forecast expenditures of \$42.167 million in 2020 and \$43.495 million in 2021.¹⁴⁸ SCE does not oppose Cal Advocates' recommendation.

We find use of a five-year average based on the more recent years to be reasonable. Therefore, we approve Cal Advocates' recommended forecasts for 2020 and 2021.

8.2.2.2. Distribution Preventative and Breakdown Capital Maintenance

Distribution Preventative and Breakdown Capital Maintenance includes the costs to replace distribution equipment identified through SCE's DIMP. SCE capitalizes this work according to SCE's accounting policy.

SCE forecasts capital expenditures of \$277.373 million for 2020 and \$286.197 million for 2021.¹⁴⁹ SCE uses a four-year average (2014-2017) of recorded expenditures to develop the forecast. SCE then reduces the average by

¹⁴⁵ Ex. SCE-13, Vol. 1, Pt. 2 at 19, Table II-9.

¹⁴⁶ Ex. SCE-02, Vol. 1, Pt. 2 at 29.

¹⁴⁷ Ex. PAO-04 at 18.

¹⁴⁸ Cal Advocates OB at 13.

¹⁴⁹ Ex. SCE-13, Vol. 1, Pt. 2 at 21, Table II-10.

the portion of recorded costs related to overhead prevention and breakdown capital work in HFRAs to account for work that will be performed under the EOI program.¹⁵⁰ Similar to the O&M forecast for this activity, SCE excludes recorded 2018 costs because 2018 was an anomalous year due to the rescheduling of work to redirect resources for EOI. SCE states that if its EOI program is not fully funded, SCE will need to restore funding to the four-year recorded average (2014-2017).

Cal Advocates agrees with SCE's forecasting methodology but provides slight adjustments to incorporate corrections in errata submitted by SCE.¹⁵¹ Cal Advocates recommends forecasts of \$277.715 million for 2020 and \$286.458 million for 2021.¹⁵²

Cal Advocates states that its forecasts are lower than SCE's forecasts but Cal Advocates' forecasts are in fact slightly higher than SCE's most recently submitted forecasts. SCE submitted several errata for its forecasts.¹⁵³ The forecasts presented in SCE's rebuttal testimony incorporate the corrections in the most recent errata and are lower than Cal Advocates' recommended forecasts. There is no dispute regarding the methodology for developing the forecasts. We find reasonable and approve the forecasts presented in SCE's rebuttal testimony, \$277.373 million for 2020 and \$286.197 million for 2021.

As discussed below in the Wildfire Management Section (Section 17.9.1.1), we make adjustments to SCE's requested capital expenditures for the EOI program. However, we do not find that these adjustments, which constitute a

¹⁵⁰ *Id.* at 20.

¹⁵¹ Cal Advocates OB at 13.

¹⁵² *Ibid.*

¹⁵³ Ex. SCE-02, Vol. 1E, Pt. 2; Ex. SCE-02, Vol. 1E2, Pt. 2; Ex. SCE-02, Vol. 1E3, Pt. 2.

small portion of SCE's overall funding request for the EOI program, warrant any additional funding for Distribution Preventative and Breakdown Capital Maintenance.

8.2.2.3. Distribution Transformers

SCE installs and removes a large volume of distribution transformers on a regular basis. This work includes three sub-activities: (1) transformers for routine, ongoing programs; (2) transformers installed in concert with the Distribution Pole Loading Program (PLP); and (3) transformers installed as part of the Wildfire Covered Conductor Program (WCCP).

SCE forecasts capital expenditures of \$98.244 million for 2020 and \$105.243 million for 2021.¹⁵⁴ SCE's Distribution Transformers forecast is dependent on the capital expenditure forecasts for 44 different distribution activities.¹⁵⁵ SCE uses a computer model to forecast the transformer program costs for each distribution activity by: (1) calculating the average activity spend per transformer for each activity based on a five-year (2014-2018) weighted average; (2) dividing the capital expenditure forecast for each activity by the average activity spend per transformer to determine a transformer quantity forecast; and (3) multiplying the quantity forecast by the transformer unit cost for each activity.¹⁵⁶ For Distribution PLP transformers, SCE proposes to use 4.17 percent of the forecast for the Distribution PLP Replacement program to forecast transformer costs.¹⁵⁷

¹⁵⁴ Ex. SCE-13, Vol. 1, Pt. 2 at 23, Table II-11.

¹⁵⁵ Ex. PAO-04 at 22.

¹⁵⁶ Ex. SCE-02, Vol. 1, Pt. 2 at 56-57.

¹⁵⁷ Ex. SCE-02, Vol. 1E2, Pt. 2 at 58.

Cal Advocates forecasts capital expenditures of \$94.785 million in 2020 and \$104.039 million in 2021.¹⁵⁸ Cal Advocates agrees with SCE's methodology and develops its forecast using the same computer model. Cal Advocates' forecast differs from SCE's forecast due to differences in the parties' capital expenditure forecasts for the different underlying distribution activities.

We find reasonable and approve SCE's unopposed methodology for deriving the Distribution Transformers forecast. Based on the capital forecasts we adopt for the 44 different distribution activities, we approve a Distribution Transformers capital expenditure forecast of \$93.329 million in 2020 and \$99.431million in 2021.¹⁵⁹

8.2.2.4. Prefabrication

Each of SCE's district service centers has a prefabrication operation responsible for staging material for the construction crews, assembling prepackaged kits, and properly disposing of materials removed from jobsites. Prefabrication includes costs for SCE's Distribution PLP as well as costs for all other capital work performed on the distribution grid.

SCE forecasts capital expenditures of \$18.843 million in 2020 and \$22.398 million in 2021 for Prefabrication.¹⁶⁰ For Distribution PLP Prefabrication costs, SCE proposes to use 2.83 percent of the forecast for the Distribution PLP Replacement Program. For non-PLP Prefabrication costs, SCE proposes to use last year recorded (2018) costs as the forecast.

¹⁵⁸ Ex. PAO-04 at 23.

¹⁵⁹ These amounts were derived using SCE's Computer Model.

¹⁶⁰ Ex. SCE-13, Vol. 1, Pt. 2 at 24, Table II-12.

Cal Advocates' forecast expenditures for the Prefabrication program are \$17.583 million in 2020 and \$18.009 million in 2021.¹⁶¹ Cal Advocates does not object to the methodology used by SCE. Cal Advocates' forecast differs from SCE's forecast due to differences in the parties' PLP Replacement Program forecasts.

We find reasonable and approve SCE's unopposed methodology for deriving the Prefabrication forecast. Based on the funding we approve for the Distribution PLP Replacement Program, discussed in the Poles Section (Section 15.2.1), we approve Prefabrication capital expenditures of \$18.843 million in 2020 and \$22.398 million in 2021.

8.3. Safety and Reliability Investment Incentive Mechanism

In the last several GRCs, the Commission has adopted some form of a Safety and Reliability Investment Incentive Mechanism (SRIIM) to require SCE to spend funds on safety and reliability as authorized or make refunds to ratepayers. SRIIM is comprised of two components: (1) hiring and maintaining a workforce of field employees that directly work on safety and reliability-related projects and programs, and (2) capital investment on core safety and reliability-related projects and programs.

SCE proposes to continue the SRIIM with modifications to the headcount classifications, headcount target, headcount measurements, and capital investment component. We approve continued use of the SRIIM adopted in the 2018 GRC with the modifications discussed below.

¹⁶¹ Ex. PAO-04 at 22.

8.3.1. Headcount Classifications

SCE proposes to maintain the SRIIM workforce classifications adopted by the Commission in SCE's 2018 GRC with two modifications: (1) remove the positions of Distribution Apprentice Groundman and Transmission Apprentice Groundman since SCE does not have these positions, and (2) add the classifications of Distribution Apparatus Technician and Distribution Apparatus Foreman. SCE's proposed changes to the workforce classifications are unopposed and are adopted.

8.3.2. Headcount Target

SCE proposes to increase the SRIIM headcount target from 2,175 to 2,465 workers. Consistent with the mechanism adopted in the 2018 GRC, SCE proposes to adjust the target headcount level by one-half the percentage change in requested versus authorized transmission and distribution (T&D) capital. If SCE fails to achieve the headcount target, SCE agrees to refund customers in the same manner as approved in the 2018 SRIIM (*i.e.*, SCE will refund \$20,000 for each employee shortfall relative to the target, up to 50 employees short, and \$80,000 per employee thereafter.)

Cal Advocates opposes an increase to the headcount target. Cal Advocates notes that SCE appears to have concerns about achieving its current headcount target and argues that, if SCE has such concerns, it should not request a headcount increase.¹⁶²

CUE recommends the headcount target be increased to 2,608 based on applying a 6.25 percent annual growth rate from 2021 through 2023 to the Commission-adopted adjusted headcount target of 2,175 from SCE's 2018

¹⁶² Cal Advocates OB at 29.

GRC.¹⁶³ CUE argues SCE's proposed target is based on inconsistent reasoning and is too low to ensure that SCE has enough employees to complete necessary safety and reliability work in the future, including both wildfire mitigation and traditional infrastructure replacement work.¹⁶⁴ CUE also recommends that the Commission eliminate the mechanism that allows SCE to adjust the headcount target based on authorized versus requested T&D capital. CUE argues that this adjustment mechanism does not provide an incentive to SCE to train and retain SRIIM category employees and will exacerbate the current shortage of workers that can complete critical safety and reliability work.¹⁶⁵

We find SCE's proposal to increase the headcount target to 2,465 to be reasonable. SCE's proposed target is based on a hiring plan of 20 SCE field crews (or approximately 80 SCE employees) per year net of attrition and takes into account the number of crews that SCE can train and grow in a given year.¹⁶⁶ CUE does not demonstrate that its proposed target is feasible during this rate case period. CUE's proposed target is based on an SCE data response where SCE provided general guidance for estimated crew growth rates that included both SCE employees and external contractors.¹⁶⁷ SCE explains that it does not have the available training resources or budget to accommodate CUE's target headcount level.¹⁶⁸

¹⁶³ CUE OB at 15.

¹⁶⁴ *Id.* at 15-16.

¹⁶⁵ *Id.* at 18.

¹⁶⁶ Ex. SCE-13, Vol. 1, Pt. 2 at 29-30; RT, Vol. 3 at 434:20-435:2 and 441:2-23.

¹⁶⁷ Ex. SCE-13, Vol. 1, Pt. 2 at 29-30.

¹⁶⁸ *Ibid.*

We also authorize SCE to continue to adjust the target headcount level by one-half the percentage change in requested versus authorized T&D capital. We clarify that the headcount adjustment should only be based on T&D capital programs that employ SRIIM workers.¹⁶⁹ In this decision, we approve the capital funding that we find necessary for SCE to provide safe and reliable service at just and reasonable rates. We find it appropriate for SCE's staffing levels of SRIIM workers to be aligned with the authorized funding for the capital programs that are supported by SRIIM workers.

8.3.3. Headcount Measurement

SCE's currently approved SRIIM determines headcount based on the average over the last quarter of 2020 for the 2018 GRC cycle. SCE proposes to modify the measurement to account for achieving the headcount level at some point in the last two quarters of the GRC cycle. SCE argues that the current mechanism affords very little flexibility to adapt to emergent events, such as unexpected attrition, that may occur at the very end of the cycle.¹⁷⁰

Cal Advocates and CUE oppose this requested change. Cal Advocates argues that SCE has not demonstrated that the current measurement method was ineffective and prevented SCE from capturing fluctuations in headcount and achieving the target headcount level.¹⁷¹ Cal Advocates also argues that SCE's proposal is unjust and burdensome to ratepayers because SCE would satisfy the

¹⁶⁹ These capital programs are not limited to SRIIM-eligible capital programs. SCE indicates that SRIIM job classifications also support capital programs that are not SRIIM-eligible capital programs. (See Ex. SCE-13, Vol. 1, Pt. 2 at 31.)

¹⁷⁰ Ex. SCE-13, Vol. 1, Pt. 2 at 27.

¹⁷¹ Cal Advocates OB at 29.

workforce component of SRIIM and avoid providing refunds to customers if it achieves the headcount level for even one day.¹⁷²

CUE argues that averaging headcount over time is more appropriate than using a single data point because averaging takes into account variations in headcount and is not subject to manipulation.¹⁷³ CUE argues that SCE must train, hire, and retain SRIIM category employees throughout the entire cycle.

We do not find SCE's proposed change to the headcount measurement mechanism to be justified. A mechanism that measures headcount at a single point in time runs counter to the goals of SRIIM because it does not incentivize SCE to maintain a workforce at the targeted level. Use of an average headcount over the last quarter of the GRC cycle enables variations in headcount to be taken into account and provides incentives to maintain the targeted headcount level over a period of time.

8.3.4. Capital Investments

SCE proposes that the Commission continue the capital investment component of the SRIIM, with the modification that any underspend in the SRIIM capital categories can be offset by one or more of the following conditions: (1) spending in excess of 110 percent of the authorized amount for "High Priority" programs (Storms, Claims, and Customer Driven/Requested Work); and (2) spending above Commission-authorized amounts in wildfire mitigation programs that use the same types of resources as those performing SRIIM work.¹⁷⁴ SCE argues this modification will provide SCE greater flexibility to

¹⁷² *Ibid.*

¹⁷³ CUE OB at 22.

¹⁷⁴ Ex SCE-2, Vol. 1, Pt. 2 at 64.

continue investment in core SRIIM categories while being able to address emergent and unanticipated customer needs and wildfire risks.

CUE finds the wildfire exception to be “generally reasonable because the wildfire mitigation programs are related to safety and reliability.” CUE argues, however, that the Commission should only approve the wildfire exception if it eliminates the headcount adjustment mechanism.

We find reasonable and adopt SCE’s proposed modification to the capital component. The capital component, as modified, will continue to incentivize spending in safety and reliability while providing SCE with greater flexibility to address emergent safety and reliability risks and unexpected customer requests.

CUE does not provide a convincing reason as to why the headcount adjustment mechanism should be eliminated if SCE’s requested modification to the capital component is adopted. For the reasons discussed above, we find SCE’s continued use of the headcount adjustment mechanism to be reasonable.

9. Meter Activities

Meter Activities encompass all elements associated with the life span of a customer’s meter. SCE states the work done in these activities “is required for the safety and reliability of the meter system, guards against the issues caused by technology obsolescence, allows customers to receive timely billing, makes sure that all customers pay their fair share for the electricity they use, and protects against the safety issues caused by energy theft.”¹⁷⁵

¹⁷⁵ Ex. SCE-02, Vol. 1, Pt. 3 at 4.

SCE forecasts combined 2021 TY O&M expenses of \$37.541 million and combined 2019-2021 capital expenditures of \$101.548 million for Meter Activities.¹⁷⁶

Cal Advocates recommends SCE's O&M forecasts be adopted as proposed.¹⁷⁷ Cal Advocates recommends a reduction of \$6.9 million in capital expenditures over the 2019-2021 period to account for a supply chain disruption SCE experienced in 2017, but otherwise does not oppose SCE's capital forecast.¹⁷⁸

9.1. Meter O&M

Meter O&M activities include: (1) Meter Engineering, Field Meter Maintenance, and Field Meter Testing (\$15.466 million); (2) Field Meter Reading (\$6.111 million); (3) Meter Installations, Removals, and Relocations (\$7.978 million); (4) Customer Installation and Energy Theft (\$4.555 million); and (5) Meter System Maintenance Design (\$3.431 million).¹⁷⁹

SCE forecasts all its O&M activities using 2018 recorded spending data, stating it expects to continue performing these activities at current levels.¹⁸⁰ SCE's 2018 recorded amounts were \$12.6 million lower than authorized in the 2018 GRC, which SCE attributes to changes in accounting treatment and operational improvements to reduce O&M costs.¹⁸¹

We find reasonable and adopt SCE's uncontested O&M forecasts.

¹⁷⁶ Ex. SCE-13, Vol. 1, Pt. 3, Table I-4 at 2.

¹⁷⁷ Ex. PAO-06 at 3.

¹⁷⁸ Ex. PAO-03 at 8-10.

¹⁷⁹ Ex. SCE-02, Vol. 1, Pt. 3 at 1.

¹⁸⁰ *Id.* at 12, 14, 16, 18 and 21.

¹⁸¹ *Id.* at 5.

9.2. Meter Capital

SCE's 2019-2021 capital forecast for Meter Activities includes \$99.460 million for Meter Engineering and \$2.088 million for Meter System Maintenance Design.¹⁸²

Meter Engineering is comprised of two main activities: (1) routine meter work and (2) non-routine meter-related projects. Routine meter work includes the meters needed to meet forecast customer growth, the replacement of defective or damaged meters outside their warranty period, and meter technology changes. SCE's 2019-2021 capital expenditure forecast for routine meter work is \$51.759 million, based on a three-year average (2016-2018) of historical routine meter work for 2020-2021 plus recorded 2019 expenses.¹⁸³ SCE asserts the three-year average captures growth and replacements, which have been static over the past three years, as well as inventory management due to technology obsolescence.¹⁸⁴ SCE did not include 2014 and 2015 in developing its forecast because, according to SCE, these years reflect costs of meter repairs made under vendor warranty and thus "are not representative of future needs."¹⁸⁵

Non-routine meter-related projects are comprised of the following activities: replacement of 15,000 cell relays¹⁸⁶ and 29,400 Point-to-Point Meters due to obsolescence; replacement of 17,000 real time energy meter (RTEM)

¹⁸² Ex. SCE-13, Vol. 1, Pt. 3, at 4, Table I-4.

¹⁸³ *Ibid*; also, Ex. SCE-02, Vol. 1, Pt. 3 at 25.

¹⁸⁴ Ex. SCE-02, Vol. 1, Pt. 3 at 24-25.

¹⁸⁵ *Id.* at 25.

¹⁸⁶ Cell relays work in conjunction with Smart Meters to collect customer interval data and relay that information back to SCE's Network Manage System. One cell relay can transmit data for up to 500 Smart Meters. (*See* Ex. SCE-02, Vol. 1, Pt. 3 at 23.)

meters (used for customer demands in excess of 200 kW) due to their reliance of radio technology which will no longer be supported; the Catalina Meter Replacement Program, which will convert 2,600 legacy electromechanical meters to over-the-air meters; the replacement of 5,000 complex meters currently deployed on commercial accounts and that have been identified as a safety risk; and the installation of a Broadband Global Area Network device to transmit customer billing, meter events, and performance data through a satellite signal in remote areas where cellular service is unavailable. SCE's combined 2019-2021 forecast for non-routine meter-related projects is \$47.701 million, based on per-project unit volumes and unit costs.¹⁸⁷

Meter System Maintenance Design supports the networking, engineering, and infrastructure costs for new RTEM meter deployment, as well as resolving network performance issues. RTEM meters are used for SCE's largest customers, with demands in excess of 200 kW, which typically require more complex metering systems to accommodate the associated rates and billing options for these customers.¹⁸⁸ SCE's forecast of \$2.088 million for these activities over the 2019-2021 timeframe is based on 2019 recorded costs, the replacement of 225 router nodes,¹⁸⁹ and an annual forecast of 656 RTEM devices to be added to the network or that require additional network infrastructure.¹⁹⁰

¹⁸⁷ Ex. SCE-02, Vol. 1, Pt. 3 at 23-25; also, Ex. SCE-13, Vol. 1, Pt. 3, at 4, Table I-4.

¹⁸⁸ Ex. SCE-02, Vol. 1, Pt. 3 at 23 and 27.

¹⁸⁹ Network packet router nodes are used to maintain communication to the entire population of RTEM meters. (See Ex. SCE-02, Vol. 1, Pt. 3 at 28.)

¹⁹⁰ Ex. SCE-02, Vol. 1, Pt. 3 at 27-28; Ex. SCE-13, Vol. 1, Pt. 3, Table I-4 at 4.

Cal Advocates observes that the three-year average used for routine meter work includes 2017 costs that are significantly higher than the other two years,¹⁹¹ which SCE attributes to having purchased additional inventory ahead of schedule due to “a manufacturer that was moving a major portion of its meter production to a new location.”¹⁹² Cal Advocates argues the supply chain disruption in 2017 is an extraordinary event that further reduced demand in 2018, and recommends the Commission use recorded 2016 Meter Engineering routine meter work capital expenditures of \$13.5 million for the 2019-2021 period on a yearly basis.¹⁹³

In response, SCE argues that meter purchases are not static year-to-year, and that using recorded expenditures from any single year is not a reliable methodology. Further, SCE highlights that it was required to increase its purchases in 2019 because of meter manufacturing inventory challenges due to technology obsolescence, which SCE asserts undermines Cal Advocates’ speculation that 2017 was an abnormal year. Finally, SCE asserts its recorded costs should be adopted for 2019.¹⁹⁴

If recorded expenses have significant fluctuations from year-to-year, or if expenses are influenced by external forces beyond the utility’s control, a multi-year average of recorded data is likely to yield a more reliable forecast than a forecast predicated upon a single year’s data.¹⁹⁵ We find, and it is undisputed,

¹⁹¹ SCE spent \$13.5 million in 2016, \$21 million in 2017, and \$13.1 million in 2018. (See Ex. SCE-02, Vol. 1, Pt. 3, at 25, fn. 16.)

¹⁹² Ex. PAO-03WP at 1.

¹⁹³ Ex. PAO-03 at 9-10.

¹⁹⁴ Ex. SCE-13 Vol. 1, Pt. 3 at 6-7.

¹⁹⁵ D.04-07-022 at 16-17.

that the significant variation in SCE's year-to-year routine meter work supports the use of a three-year average in this instance. However, we would not expect the specific event leading to SCE's increased 2017 purchases, namely, the decision by a manufacturer to move a major portion of its meter production to a new location, to be a regular occurrence or a reliable indicator of future expenditures. Therefore, we will use recorded 2019 data instead of 2017 data, calculating the three-year average based on 2016, 2018 and 2019 recorded data. Further, it is not uncommon for GRCs to update forecasts based on recent recorded information, especially for plant-related items,¹⁹⁶ and we agree it is appropriate to use SCE's 2019 recorded data in this instance. We approve a capital expenditure budget of \$51.229 million for Meter Engineering routine meter work during 2019-2021, as shown in the table below (Nominal \$000), which is a reduction of \$530,000 from SCE's request:

Activity	2019	2020	2021
Meter Engineering Routine Work	20,159	15,535	15,535

SCE's remaining capital expenditures for 2019-2021, including \$47.701 million for Meter Engineering non-routine meter-related projects and \$2.088 million for Meter System Maintenance Design, are uncontested. We find reasonable and adopt these uncontested capital expenditure forecasts.

10. Transmission Grid

SCE's transmission and sub-transmission system is comprised of over 13,000 miles of transmission lines that operate at voltage levels of 500 kV, 220 kV, 161 kV, 115 kV, 66 kV, 55 kV, and 33 kV. SCE also operates and maintains a communications network that includes over 5,000 miles of fiber-optic cable.

¹⁹⁶ D.06-05-016 at 212.

10.1. Transmission Grid O&M

SCE forecasts TY O&M expenses of \$42.931 million for the Transmission Grid Business Planning Group, which is responsible for inspection and maintenance of the transmission grid and communication network.¹⁹⁷ This forecast includes work for the following activities:

Activity	TY Forecast (\$000)
Transmission Line Patrols	7,224
Transmission O&M Maintenance	20,818
Telecommunications Inspection and Maintenance	4,874
Transmission Line Rating Remediation	1,790
Insulator Washing	761
Roads and Rights of Way	4,665
Transmission Underground Structure Inspection	1,943
Transmission Support Activities	857
Total	42,931

Cal Advocates recommends a TY forecast of \$29.169 million.

Cal Advocates recommends adjustments to SCE's forecasts for: (1) Transmission Line Patrols; (2) Transmission O&M Maintenance; (3) Telecommunications Inspection and Maintenance; and (4) Transmission Line Rating Remediation. Cal Advocates finds the remainder of SCE's O&M forecasts for the Transmission Grid Business Planning Group to be comparable to historical expense levels and does not oppose them.¹⁹⁸

¹⁹⁷ Ex. SCE-13, Vol. 2E at 3, Table I-3 Ex. SCE-52A2E2, Appendix C at C9. This forecast reflects SCE's removal of AB 560 costs for Transmission Line Patrols in update testimony. As discussed further below, SCE's forecasts for the sub-activities included in the Transmission O&M Maintenance activity total \$20.818 million, not \$21.064 million as presented in Ex. SCE-13, Vol. 2E. (Ex. SCE-02, Vol. 2A at 17, Table II-3.)

¹⁹⁸ Cal Advocates OB at 35.

We find SCE has provided adequate justification for the unopposed Insulator Washing, Roads and Rights of Way, Transmission Underground Structure Inspection, and Transmission Support Activities forecasts.¹⁹⁹ We find reasonable and adopt the unopposed forecasts. The contested forecasts are discussed below.

10.1.1. Transmission Line Patrols

SCE performs annual patrol inspections of every transmission right-of-way and transmission line components (*i.e.*, structures, poles, electrical lines, and other related equipment) within the SCE transmission system, in accordance with GOs 95 and 165. SCE also performs inspections after unplanned events, such as extreme weather, fires, and equipment malfunctions.

SCE forecasts TY O&M expenses of \$7.224 million for Transmission Line Patrols based on 2018 last-year recorded values (\$4.378 million), with an adjustment for forecast incremental costs (\$2.855 million) for planned new aerial inspections.²⁰⁰ Starting in 2021, SCE plans to perform aerial inspections on one-third of SCE's non-HFRAs every year. SCE states it has historically performed limited line patrols via helicopter but that aerial inspection of non-HFRAs is completely new and different as it focuses on detailed asset inspections (including infrared, corona, and high-definition imaging).²⁰¹ SCE's cost forecast for the aerial inspection work is based on estimated costs per mile

¹⁹⁹ SCE describes in detail the activities and basis for its cost forecasts in Ex. SCE-02, Vol. 2A.

²⁰⁰ Ex. SCE-02, Vol. 2A at 12, Table II-2; Ex. SCE-52A2E2, Appendix C at C9. This amount reflects SCE's removal of AB 560 costs in update testimony. The aerial inspection costs are limited to non-HFRAs, the costs for aerial inspection in HFRAs are addressed in the Wildfire Management Section.

²⁰¹ Ex. SCE-02, Vol. 2A at 10; Ex. SCE-13, Vol. 2 at 6, fn. 11.

scanned, the costs of a camera sensor operator, and the costs for processing and reviewing aerial inspection results.²⁰²

Cal Advocates recommends TY O&M expenses of \$5.330 million for SCE's Transmission Line Patrols.²⁰³ Cal Advocates uses SCE's 2018 recorded adjusted expenses as the basis for its forecast and then normalizes SCE's incremental request of \$2.855 million over the three-year rate case cycle to account for similar activities that have costs included in rates and to provide funding for additional TY activities. Cal Advocates argues SCE did not justify its forecast at the requested expense level or provide detail on similar historical costs incurred for aerial inspections for review, analysis, and comparison to its TY estimates.

We find reasonable SCE's forecast methodology based on its plan to inspect one-third of non-HFRAs every year, the estimated costs per mile scanned, the costs of a camera sensor operator, and the costs for processing and reviewing aerial inspection results. However, the workpaper submitted by SCE in support of its forecast indicates that the incremental cost for this work is \$2.626 million.²⁰⁴ Based on the supporting documentation provided by SCE, we find it reasonable to approve \$2.626 million for the incremental aerial inspection work. Cal Advocates does not oppose SCE's rationale for including an incremental adjustment for the new aerial inspections or the scope of the planned work. Given the scope of the planned work, we do not find justification to normalize (*i.e.*, reduce by two-thirds) SCE's TY forecast as proposed by Cal Advocates. Therefore, we approve a TY forecast of \$6.995 million based on SCE's

²⁰² Ex. SCE-02, Vol. 2A at 12; Ex. SCE-13, Vol. 2 at 7, Appendix A at A-7.

²⁰³ Cal Advocates OB at 40.

²⁰⁴ Ex. SCE-13, Vol. 2, Appendix A at A-7.

2018 recorded costs with an adjustment of \$2.626 million for incremental aerial inspection work.

10.1.2. Transmission O&M Maintenance

Transmission O&M Maintenance includes both proactive and reactive maintenance on transmission line equipment and structures, such as poles, towers, conductors, and other components, including Federal Aviation Administration (FAA) tower lighting and marker balls. SCE's TY forecast for the Transmission O&M Maintenance program is \$20.818 million.²⁰⁵ This forecast includes costs for five sub-activities:²⁰⁶

Sub-Activity	TY Forecast (\$000)
Transmission O&M Maintenance (sub-activity)	5,189
Transmission O&M Breakdown	1,158
Transmission O&M Encroachments	1,691
Aerial Inspection Maintenance Program	11,894
Maintenance for FAA Lighting	886
Total	20,818

Cal Advocates recommends a TY O&M forecast of \$12.208 million.²⁰⁷

Cal Advocates recommends adjustments to SCE's forecasts for the Transmission O&M Maintenance and Aerial Inspection Maintenance Program sub-activities. Cal Advocates does not oppose SCE's forecasts for the Transmission O&M Breakdown, Transmission O&M Encroachments, and Maintenance for FAA Lighting sub-activities. Cal Advocates finds these forecasts to be reasonable in

²⁰⁵ SCE also presents its TY Transmission O&M Maintenance forecast as \$21.064 million. (Ex. SCE-02, Vol. 2A at 16, Figure II-7.) However, SCE's itemized sub-activity forecasts total \$20.818 million and there is no justification provided for a \$21.064 million forecast. (*Id.* at 17, Table II-3.)

²⁰⁶ *Ibid.*

²⁰⁷ Cal Advocates OB at 36.

light of SCE's testimony, workpapers, data request responses, and historical expense levels.²⁰⁸

We find SCE has provided adequate justification for the unopposed sub-activity forecasts.²⁰⁹ We find reasonable and adopt the unopposed forecasts. The contested sub-activity forecasts are discussed below.

**10.1.2.1. Transmission O&M Maintenance
(Sub-activity)**

SCE forecasts \$5.189 million for Transmission O&M Maintenance sub-activity TY expenses.²¹⁰ SCE's forecast is based on a four-year average (2015-2018) of recorded costs. SCE argues a four-year average is appropriate because costs can reasonably be expected to fluctuate substantially from year to year due to the variable nature of the work for this activity.

Cal Advocates recommends a TY forecast of \$4.508 million based on 2018 last-year recorded costs.²¹¹ Cal Advocates notes that SCE's recorded expenses have declined each year between 2014 and 2018 and that SCE fails to justify use of a four-year average, which results in incremental funding of \$0.681 million over 2018 recorded expenses.

We find SCE has failed to justify basing the forecast on the four-year average. Although SCE argues costs for this sub-activity can fluctuate, SCE's recorded costs from 2014-2018 demonstrate a yearly downward trend.²¹² The Commission has held that if recorded expenses have shown a trend in a certain

²⁰⁸ *Id.* at 36-37.

²⁰⁹ Ex. SCE-02, Vol. 2A at 17-20.

²¹⁰ *Id.* at 17.

²¹¹ Cal Advocates OB at 37.

²¹² Ex. SCE-02, Vol. 2A at 17, Table II-4.

direction over three or more years, the last recorded year is an appropriate base estimate.²¹³ Therefore, we find reasonable and adopt Cal Advocates' TY forecast of \$4.508 million for this sub-activity.

**10.1.2.2. Aerial Inspection Maintenance Program
(Sub-activity)**

SCE expects its aerial inspection program will inspect over 32,000 transmission assets per year and generate additional maintenance work. SCE forecasts TY O&M expenses of \$11.894 million for this additional maintenance work.²¹⁴

Cal Advocates recommends a TY forecast of \$3.965 million based on normalizing SCE's TY forecast over the three-year rate case cycle.²¹⁵ Cal Advocates argues its estimate provides a reasonable forecast of TY expenses for the newly established program given the lack of supporting data and uncertainties in the proposed activities.

To develop its TY forecast, SCE estimates a total notification "find rate"²¹⁶ of 8,044 notifications per year based on recorded "find rates" of 25 percent from SCE's EOI program in 2018 and 2019.²¹⁷ SCE then estimates the number of notifications for common maintenance notification types (such as pole repair, tower repair, vegetation management, conductor repair, and other O&M)²¹⁸ by multiplying the total number of notifications by the expected frequency for each

²¹³ D.04-07-022 at 15 quoting D.89-12-057, 34 CPUC 2d 199, 231.

²¹⁴ Ex. SCE-02, Vol. 2A at 18-19.

²¹⁵ Cal Advocates OB at 38.

²¹⁶ A "find rate" is the probability of finding defective equipment in a population or sample of inspections.

²¹⁷ Ex. SCE-02, Vol. 2A at 18-19; Ex. SCE-13, Vol. 2 at 12.

²¹⁸ SCE's forecast also includes forecast costs for pole replacements. These costs are capital maintenance items and are included under Transmission Capital Maintenance.

type. SCE develops a cost estimate for each type by multiplying the expected number of notifications for the type by its five-year average unit costs. The sum of the cost estimates for each type produces the total program cost.²¹⁹

Although this is a new program with no historic costs, we find SCE's forecast methodology based on recorded EOI "find rates" and average replacement costs based on past work orders to be adequately supported and reasonable. We do not find justification to normalize (*i.e.*, reduce by two-thirds) SCE's TY forecast as proposed by Cal Advocates. Therefore, we approve SCE's TY O&M forecast of \$11.894 million for this sub-activity.

10.1.3. Telecommunications Inspection and Maintenance

SCE's telecommunication (telecom) network provides critical communications connections to substations, customer call centers, data centers, and office facilities. SCE forecasts TY O&M expenses of \$4.874 million for Telecommunications Inspections and Maintenance. This activity covers inspection of SCE's telecom lines, as well as the breakdown and planned maintenance of SCE's telecom assets. SCE derives the forecast based on recorded 2018 costs (\$2.419 million) with an incremental adjustment (\$2.455 million) for new and expanded work activities.²²⁰

Cal Advocates recommends a TY forecast of \$2.419 million based on recorded 2018 costs.²²¹ Cal Advocates argues SCE's forecast includes incremental funding for regular, ongoing, and routine activities that already have costs embedded in rates and would result in ratepayers funding these activities

²¹⁹ Ex. SCE-02, Vol. 2A at 19, Table II-7.

²²⁰ *Id.* at 26, Table II-9.

²²¹ Cal Advocates OB at 42.

twice.²²² Cal Advocates also notes SCE's 2018 recorded expenses include \$305,788 in "premium" or overtime costs that SCE can reallocate and utilize in the TY for additional positions.²²³

SCE argues the forecast activities for the program involve new, expanded work scope as the program is evolving from a reactive to a proactive program. SCE currently inspects cables in HFRA's annually and intends to inspect all cables in non-HFRA's on a five-year cycle starting in 2020.²²⁴ SCE argues the incremental funding request is justified because the program's activities and number of employees are increasing to reflect new inspection schedules in non-HFRA's and resulting maintenance.²²⁵ SCE also asserts that there is no embedded funding in rates because it has not asked for funding for this activity in any previous GRCs.²²⁶

We find that SCE fails to justify its requested \$2.455 million increase above 2018 recorded costs. SCE argues it is moving from a reactive to a proactive approach to inspections and maintenance in order to conform with GO 95 requirements.²²⁷ SCE is required to conduct communication line patrols and detailed inspections of communication lines in accordance with GO 95, Section 80.1.A(1) for joint-use poles in HFRA's and GO 95, Section 80.1.A(2) for all its

²²² *Ibid.*

²²³ *Id.* at 43.

²²⁴ Ex. SCE-02, Vol. 2A at 24.

²²⁵ SCE OB at 56. SCE estimates hiring twenty-four new employees for this additional work. SCE developed this estimate by analyzing the average man-hours per inspection of HFRA circuits currently being patrolled, the geographic size of SCE territory, the number of telecom assets, and expected requirements of the new patrol program. (Ex. SCE-02, Vol. 2A at 26.)

²²⁶ SCE OB at 57.

²²⁷ Ex. SCE-13, Vol. 2 at 16.

communication lines throughout the State. In 2017, the Commission adopted some modifications to these requirements.²²⁸ However, SCE was required to conduct regular and ongoing inspections of its telecommunication lines even prior to these modifications and SCE fails to explain how the modifications would justify a more than doubling of its 2018 recorded costs.

Although SCE states that inspection and maintenance work will now be proactively conducted pursuant to a schedule, it is unclear how much of the forecast work is incremental to the level and types of activity conducted in prior years. For example, SCE states that it regularly completed planned inspections of telecommunication assets within HFRA's prior to 2019.²²⁹ However, SCE's workpapers indicate that costs for HFRA circuit inspections are included in the incremental \$2.445 million request.²³⁰ Moreover, SCE was not able to provide details regarding the costs it incurred for inspection and maintenance work on telecommunication cables in HFRA's and non-HFRA's from 2014-2019 because SCE's accounting system did not provide for the level of granular tracking to determine the costs recorded to perform these activities.²³¹

SCE does not adequately explain why its 2018 recorded costs would be insufficient to conduct the inspections required pursuant GO 95 and associated maintenance work. Therefore, we find it reasonable to approve a forecast of \$2.419 million based on SCE's 2018 recorded costs.

²²⁸ D.17-12-024. The Commission directed that the amended regulations be fully implemented in Tier 3 by September 1, 2018 and Zone 1 and Tier 2 by June 30, 2019. (D.17-12-024 at 154-155, OP 4.)

²²⁹ Ex. SCE-13, Vol. 2 at 15, fn. 42.

²³⁰ *Id.*, Appendix A at A-12.

²³¹ Ex. PAO-06 at 39-40.

10.1.4. Transmission Line Rating Remediation

The Transmission Line Rating Remediation (TLRR) program is a product of SCE's efforts to identify and remediate transmission lines potentially in violation of GO 95, Rule 37, Table 1 and/or GO 95, Rule 38, Table 2,²³² based on a light detection and ranging technology (LiDAR) study launched in 2006. The O&M remediation work typically includes re-tensioning circuit conductors, re-framing towers, and grading the land under a transmission line.

SCE forecasts TY O&M expenses of \$1.790 million for its TLRR program.²³³ SCE uses engineering and program management estimates to develop forecast costs on a project basis. SCE prioritizes the projects according to compliance deadlines set by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC).

Cal Advocates recommends a TY forecast of \$0.959 million based on a five-year average (2014-2018).²³⁴ Cal Advocates argues SCE's forecast methodology lacks details and cannot be substantiated. Cal Advocates also argues SCE's "underspending in the 2018 GRC for its TLRR program demonstrates that this project is still in its early planning stages and apparently has not yet advanced far enough for SCE to provide specifics on the TY project estimates."²³⁵

²³² Table 1 specifies the basic minimum allowable vertical clearance of wires above railroads, thoroughfares, ground or water services; also, clearances from poles, buildings, structures, or other objects. Table 2 specifies the basic minimum allowable clearance of wires from other wires at crossings, in midspans, and at supports.

²³³ Ex. SCE-02, Vol. 2A at 37.

²³⁴ Cal Advocates OB at 45.

²³⁵ *Id.* at 46.

We find SCE has provided adequate justification for its forecast. SCE explains there are 8,327 discrepancies that remain to be remediated by the NERC/WECC deadlines of 2025 for bulk electrical facilities and 2030 for radial facilities.²³⁶ Since the 2018 GRC, SCE has inspected every identified bulk transmission line discrepancy.²³⁷ SCE evaluates all the discrepancies on an entire circuit basis to allow for a holistic and effective remediation strategy. Based on the inspection results, SCE forecasts fourteen TLRR projects to be started or completed in the TY and expects the level of TLRR work and costs to continue at the same level through this GRC cycle.²³⁸

We find SCE's projected scope of work for this GRC cycle to be reasonable in light of the compliance deadlines and the fact that it is based on actual inspection results. Based on the projected scope of work, we agree the recorded costs are not an appropriate basis for the forecast. We find SCE's project-based forecast to be reasonable and approve SCE's TY forecast of \$1.790 million.

10.2. Transmission Grid Capital Expenditures

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast Transmission Grid capital expenditures (nominal, \$000):²³⁹

²³⁶ Ex. SCE-02, Vol. 2A at 36.

²³⁷ Ex. SCE-13, Vol. 2 at 18.

²³⁸ *Id.* at 18, Appendix A at A-13.

²³⁹ *Id.* at 4, Table I-4; Ex. SCE-18, Vol, 1, Appendix A at A-92. SCE presents its 2019 recorded costs for Transmission Capital Maintenance as \$51.528 million in Ex. SCE-13, Vol. 2 and as \$32.865 million in Ex. SCE-18, Vol. 1. Given the lack of explanation for the discrepancy, we find the lower amount presented to be reasonable.

Capital Expenditures	2019	2020	2021
Transmission Capital Maintenance	32,865	48,548	89,799
Telecommunication Capital Maintenance	5,384	3,239	3,286
Transmission Claims	4,315	3,666	3,745
Transmission Line Remediation Program	116,321	94,912	133,414
Transmission Emergency Equipment	-	158	162
Transmission Tools and Work Equipment	812	1,364	1,393
Total	159,697	151,887	231,799

Cal Advocates opposes SCE's forecast expenditures for the Aerial Inspection Maintenance sub-activity within Transmission Capital Maintenance. The remainder of SCE's recorded costs and forecasts are unopposed. We find SCE has provided adequate justification for the unopposed forecasts.²⁴⁰ We find the 2019 recorded costs and unopposed 2020-2021 forecasts (including the unopposed forecasts within Transmission Capital Maintenance)²⁴¹ to be reasonable and adopt them. The contested Aerial Inspection Maintenance forecast is discussed below.

10.2.1. Aerial Inspection Maintenance

As discussed above with respect to Transmission O&M Maintenance, SCE expects that its new aerial inspection program will generate additional maintenance work. SCE categorizes the additional maintenance work for pole replacements as capital items. SCE forecasts TY capital expenditures of \$22.461 million for pole replacements under Aerial Inspection Maintenance.²⁴² SCE forecasts the number of pole replacements based on the same notification

²⁴⁰ SCE describes in detail the activities and basis for its cost forecasts in Ex. SCE-02, Vol. 2A.

²⁴¹ SCE categorizes Transmission Capital Maintenance into two parts: (1) On-going Maintenance Work, and (2) Tower Corrosion Program. SCE further categorizes the On-going Maintenance Work into the following sub-categories: (1) Ongoing Maintenance; (2) Aerial Inspection Maintenance; (3) Breakdown; and (4) Encroachments. (Ex. SCE-02, Vol. 2A at 27-32.)

²⁴² Ex. SCE-13, Vol. 2 at 20, Table II-9.

“find rate” methodology used for its O&M Aerial Inspection Maintenance Program.²⁴³ SCE then reduces this forecast by 30 percent to avoid duplication and account for notifications under SCE’s pole program.²⁴⁴ SCE multiplies the total number of adjusted notifications by a unit cost estimate of \$24,661 for each replacement.²⁴⁵

Cal Advocates recommends a TY forecast of \$15 million for this activity.²⁴⁶ Cal Advocates argues SCE’s forecast is based on subjective judgment and is uncertain because SCE has no comparable historical data available to use as a basis for its forecast. Cal Advocates acknowledges that as a new program the costs may be higher than its recommendation. Therefore, Cal Advocates recommends that the Commission authorize a memorandum account for SCE to track costs incurred above the forecast amount.

SCE argues its forecast is based on sound, objective forecasting methods and data. SCE states that the “find rate” for this program is based on the recorded 2018 and preliminary 2019 “find rates” for the EOI program and that the unit cost estimate is based on historical averages recorded by SCE’s Pole Replacement Programs.²⁴⁷ SCE also notes that in D.20-03-004, the Commission approved SCE’s Advice Letter 4120-E, in which SCE used the same methodology to forecast aerial inspection costs for EOI.²⁴⁸

²⁴³ Ex. SCE-02, Vol. 2AE at 29; Ex. SCE-02, Vol. 2A at 19, Table II-7.

²⁴⁴ Ex. SCE-02, Vol. 2AE at 29.

²⁴⁵ Ex. SCE-13, Vol. 2 at 21, Appendix A at A-5.

²⁴⁶ Cal Advocates OB at 33.

²⁴⁷ SCE OB at 60.

²⁴⁸ *Id.* at 61.

SCE also opposes Cal Advocates' recommendation for a memorandum account for these expenditures.²⁴⁹ SCE argues that if the Commission determines there is a need to track SCE's activity more closely, it would be more appropriate to authorize a two-way balancing account. However, SCE argues a two-way balancing account is still not necessary because its forecast is sufficiently justified and substantiated.

Although there are no historical costs for this specific program, we find SCE's forecast methodology based on recorded EOI "find rates" and pole replacement costs under other programs to be adequately supported and reasonable with the adjustment of a pole replacement "find rate" of 12 percent rather than the 15 percent proposed by SCE. In a data request response to Cal Advocates, SCE indicated that the pole replacement "find rate" based on preliminary findings from SCE's aerial inspections of its HFRA's is a little over 12 percent.²⁵⁰ Given the lack of historical costs for this program and relatively high average unit costs, we find it reasonable to adopt the more conservative "find rate."

Therefore, we adopt a TY forecast of \$17.969 million (\$nominal) based on a total notification count of 8,044;²⁵¹ pole replacement frequency rate of 12 percent; application of a 30 percent reduction to account for duplicative work under the

²⁴⁹ *Id.* at 61-62.

²⁵⁰ Ex. PAO-03-WP at 3, SCE Response to PubAdv-SCE-107-YNL, Question 1.c.

²⁵¹ SCE's testimony also indicates that SCE expects to find 8,618 total notifications per year. (Ex. SCE-02, Vol. 2AE at 29.) However, according to SCE's workpapers, SCE's forecast of \$22.461 million is based on 8,044 total notifications. (Ex. SCE-13, Vol. 2 at 21, Appendix A at A-5; *see also* Ex. SCE-02, Vol. 2A at 19, Table II-7.)

pole program; and an average unit cost of \$24,661.²⁵² We find there is a reasonable basis for this forecast and do not find it necessary to adopt a memorandum account or balancing account for this activity.

11. Substation

SCE's system includes 188 transmission substations and 651 distribution substations as of December 31, 2018.²⁵³ Substation equipment includes circuit breakers, transformers, relays, switchers, reclosers, and other miscellaneous equipment essential to the operation of substations.

11.1. Substation O&M

SCE requests Substation O&M funding for: (1) Grid Monitoring and Operability activities, which enable SCE to maintain constant oversight and control over its transmission, sub-transmission, and distribution grids; (2) inspections and maintenance of substation equipment; and (3) indirect costs in support of Substation Capital and O&M work, including substation maintenance oversight and informational meetings.

SCE forecasts Substation TY O&M expenses of \$121.451 million. This forecast is broken down by activity as follows:²⁵⁴

²⁵² The forecast is based on rounding the number of expected pole replacements to the nearest whole number.

²⁵³ Ex. SCE-02, Vol. 3 at 46.

²⁵⁴ Ex. SCE-13, Vol. 3 at 2, Table I-1 and 3, Table I-3; Ex. SCE-52A2E2, Appendix C at C9. These forecasts reflect adjustments due to AB 560 that SCE made in update testimony.

Activity		TY Forecast (\$000)
Grid Monitoring and Operability	Monitoring Bulk Power Systems	54,836
	Monitoring and Operating Substations	41,598
Inspections and Maintenance		18,448
Capital-Related Expense and Other		6,570
Total		121,451

SCE's forecasts are unopposed with the exception of SCE's forecast for Monitoring Bulk Power Systems within the Grid Monitoring and Operability activity. All the uncontested forecasts are based on last year recorded (2018) costs or based on historical averages where there has been variability in historical costs.²⁵⁵ We find that SCE has provided adequate justification for the uncontested Monitoring and Operating Substations; Inspections and Maintenance; and Capital-Related Expense and Other forecasts and adopt them. The Monitoring Bulk Power Systems forecast is discussed below.

11.1.1. Monitoring Bulk Power Systems

SCE's bulk power system consists of equipment under California Independent System Operator (CAISO) control, which includes transmission and some lower voltages. The Monitoring Bulk Power Systems activity is supported by: (1) System Operators in the Grid Control Center (GCC) and (2) Grid Network Solutions (GNS). Cal Advocates opposes the forecasts for both GCC and GNS.

11.1.1.1. Grid Control Center (GCC)

GCC is responsible for the overall monitoring and control of SCE's transmission system and is the primary point of contact for the CAISO. GCC activities can be categorized into three main responsibilities: (1) monitoring and

²⁵⁵ SCE describes its methodologies for these forecasts in Ex. SCE-02, Vol. 3.

operating SCE's bulk power system; (2) coordinating planned outages; and (3) developing and maintaining operating procedures.²⁵⁶

SCE forecasts TY O&M expenses of \$9.982 million for GCC, consisting of \$8.362 million for labor and \$1.619 million for non-labor.²⁵⁷ The costs for this activity are primarily driven by personnel count. SCE does not expect any change in staffing levels for this activity during this GRC cycle, and therefore, bases its labor and non-labor forecasts on last year recorded (2018) costs.²⁵⁸

Cal Advocates recommends a TY forecast of \$9.338 million, consisting of \$8.537 million for labor and \$0.801 million for non-labor.²⁵⁹ Cal Advocates bases its labor forecast on the three-year average of 2016-2018 recorded costs.

Cal Advocates argues that the three years of recorded data show a stable trend and that there is unlikely to be an increase in the TY. Cal Advocates' non-labor forecast is the forecast initially presented by SCE in its direct testimony.

We find reasonable and approve SCE's TY forecast based on last year recorded costs. Cal Advocates' recommendations are in response to SCE's initial forecasts of \$9.263 million for labor and \$0.801 million for non-labor.²⁶⁰ SCE subsequently submitted errata correcting its labor and non-labor forecasts because SCE had inadvertently used an incorrect labor to non-labor ratio.²⁶¹ This error did not impact SCE's total TY request of \$9.982 million. We see no reason to adopt Cal Advocates' recommended labor forecast when SCE indicates that

²⁵⁶ Ex. SCE-02, Vol. 3 at 9.

²⁵⁷ Ex. SCE-13, Vol. 3 at 6, Table II-5; Ex. SCE-52A2E2, Appendix C at C9. This forecast reflects SCE's AB 560 adjustment of \$82,543 to labor costs presented in update testimony.

²⁵⁸ Ex. SCE-02, Vol. 3 at 12.

²⁵⁹ Cal Advocates OB at 49.

²⁶⁰ Ex. SCE-02, Vol. 3 at 11, Figure II-5

²⁶¹ Ex. SCE-02, Vol. 3E2 at 11, Figure II-5; Ex. SCE-13, Vol. 3 at 6.

there will be no change from 2018 staffing levels and when SCE's corrected labor forecast is less than Cal Advocates' recommended labor forecast. Moreover, given that SCE's initial non-labor forecast was in error, we see no discernible reason to adopt it.

11.1.1.2. Grid Network Solutions (GNS)

GNS is responsible for operating, repairing, and maintaining network communication infrastructure and Supervisory/System Control and Data Acquisition (SCADA) systems that enable the GCC to monitor and control SCE's bulk power system.

SCE forecasts TY O&M expenses of \$44.853 million for GNS. SCE's forecast consists of the following:²⁶²

- (1) Labor expenses of \$29.849 million: This forecast is an increase of \$6.862 million (30 percent) over 2018 recorded costs due to staffing increases required to support Grid Mod workstreams, specifically Field Area Network (FAN), Wide Area Network (WAN), Grid Management System (GMS), and Common Substation Platform (CSP).
- (2) Non-Labor expenses of \$12.949 million: This forecast is an increase of \$1.246 million (11 percent) over 2018 recorded costs. Most of the increase is for hardware maintenance costs to cover incremental data networking equipment added by the Grid Mod program. The remainder of the increase is to continue hardware maintenance coverage on an increasing number of data networking equipment. Moreover, an accounting change in 2018 results in higher O&M costs because hardware maintenance coverage is now expensed rather than capitalized.
- (3) "Other" telecommunication rents and leased circuits expenses of \$2.056 million: This forecast is an increase of \$353,000 (21 percent) over recorded 2018 costs due to the

²⁶² Ex. SCE-02, Vol. 3 at 14, Figure II-6 and 16-18.

renewal of a leased fiber agreement with the California Broadband Initiative and increased bandwidth costs for incremental data networking devices driven by North American Electric Reliability Corporation Critical Infrastructure Protection (NERC-CIP) 014 requirements.

SCE's incremental costs related to the Grid Mod program, which impact the labor and non-labor expense forecasts, vary over the rate case period. For ratemaking purposes, SCE normalizes the 3-year forecast for years 2021-2023 and uses the normalized amount for the 2021 forecast.²⁶³

Cal Advocates recommends a TY forecast of \$35.768 million for GNS.²⁶⁴ Cal Advocates recommends a labor forecast of \$22.606 million and a non-labor forecast of \$11.106 million based on the three-year (2016-2018) average of recorded costs. Cal Advocates opposes the use of normalization to calculate the labor forecast for 2021.²⁶⁵ Cal Advocates does not oppose SCE's forecast \$2.506 million for "other" costs.

We find that SCE has provided adequate justification for an increase above 2018 recorded costs. SCE's recorded costs for 2014-2018 reflect a linear upward trend.²⁶⁶ SCE explains that over the past few years, GNS has experienced an average of 100 incremental data networking devices added to the environment per year and a 30 percent increase in network traffic per year.²⁶⁷ SCE anticipates a substantial increase in the number of technology assets and systems put into

²⁶³ *Id.* at 16, fn. 14 and 17, Table II-4.

²⁶⁴ Cal Advocates OB at 49-50.

²⁶⁵ SCE does not normalize all labor costs but only normalizes the incremental costs for the Grid Mod program, which include both labor and non-labor costs. (Ex. SCE-02, Vol. 3 at 16, fn. 14 and 17, Table II-4.)

²⁶⁶ *Id.* at 14, Figure II-6.

²⁶⁷ *Id.* at 18.

service during this rate case cycle in support of the Grid Mod program.²⁶⁸ Cal Advocates does not dispute the incremental scope of work that SCE forecasts. Costs for such work are not included in SCE’s 2016-2018 recorded costs.²⁶⁹ Therefore, Cal Advocates’ recommended forecast based on historical 2016-2018 costs would not provide adequate funding to support approved Grid Mod projects, which require GNS support.

Although we find that an increase is justified, we find that SCE has failed to justify normalizing its 2021-2023 forecast costs related to Grid Mod to determine the TY forecast. SCE does not provide any explanation as to why costs are expected to increase from \$3.188 million in 2021 to \$4.501 million in 2022 and \$8.572 million in 2023.²⁷⁰ Given the lack of justification for such increases, we find reasonable and approve incremental costs based on the 2021 forecast of \$3.188 million rather the 2021-2023 normalized forecast of \$5.420 million, which results in a \$2.232 million reduction to SCE’s TY forecast.

Based on the foregoing, we find reasonable and approve a TY forecast of \$42.621 million for GNS.

11.2. Substation Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast substation capital expenditures (nominal, \$000):²⁷¹

Capital Expenditures	2019	2020	2021
Substation	292,091	318,377	445,448

²⁶⁸ See Ex. SCE-13, Vol. 3 at 10-11.

²⁶⁹ *Id.* at 11-12.

²⁷⁰ Ex. SCE-02, Vol. 3 at 17, Table II-4.

²⁷¹ Ex. SCE-13, Vol. 3 at 4, Table I-4.

SCE's substation capital programs support the following activities:²⁷²

- Grid Monitoring and Operability: Replacement of aged and failed equipment and adoption of new technologies for Grid Monitoring and Operability. Grid Monitoring and Operability infrastructure includes SCE's communication network, which is primarily used as a means of monitoring, operating, and controlling the electric grid, and the Grid Data Center, which operates SCE's SCADA applications.
- Inspections and Maintenance: Capital maintenance work required to replace equipment identified from inspections or breakdowns, and claims work for substation assets.
- Infrastructure Replacements: Preemptive replacement of aging and/or obsolete substation equipment prior to failure, including substation transformer replacements; substation circuit breaker replacements; relays, protection, and control replacements; substation switchrack rebuilds/upgrades, and 4kV substation eliminations.
- Capital-Related Expense and Other: Costs for substation tools and work equipment, the oil containment diversion system, and substation emergency equipment.

SCE's capital forecasts are unopposed. We find that SCE has provided adequate justification for its 2019 recorded and 2020-2021 forecast costs and approve them.

12. Grid Modernization, Grid Technology, and Energy Storage

12.1. Grid Modernization

Over the 2021 GRC period, SCE's proposed Grid Modernization investments focus on continued compliance with decisions in the Distribution Resources Plan (DRP) Proceeding (R.14-08-013), asset obsolescence, and evolving

²⁷² These activities and associated forecasts are described in Ex. SCE-02, Vol. 3; Ex. SCE-02, Vol. 3E; and Ex. SCE-13, Vol. 3.

cybersecurity threats.²⁷³ SCE's testimony includes a 10-year Grid Modernization Plan (GMP) as required by D.18-03-023,²⁷⁴ which SCE asserts will provide the following customer benefits upon implementation: mitigation of potential safety hazards, maintaining and improving grid reliability, wildfire resiliency, decarbonization, customer empowerment, and economic efficiency.²⁷⁵

SCE forecasts combined 2021 TY O&M expenses of \$7.272 million for Grid Modernization T&D Deployment Readiness and Information Technology (IT) Project Support.²⁷⁶ SCE also forecasts combined 2019-2021 capital expenditures of \$431.292 million for Engineering and Planning Software Tools (E&P Tools), SCE's Grid Management System (GMS), Communications, Automation, and distributed energy resource (DER) Hosting Capacity Reinforcement.²⁷⁷

Cal Advocates recommends a reduction of \$2.104 million to the TY O&M expenses for IT Project Support, based on arguments that SCE's forecasts of non-labor costs have varied significantly in the past.²⁷⁸ SCE's O&M request for Grid Modernization T&D Deployment Readiness is uncontested.

Key issues concerning SCE's proposed capital expenditures for Grid Modernization include: (1) the reasonableness of increases to SCE's forecast costs for E&P Tools and the GMS since the 2018 GRC, and (2) whether the Commission should authorize SCE to move forward with installing fault interrupting switches to promote distribution grid automation. Specifically, Cal

²⁷³ Ex. SCE-02, Vol. 4, Pt. 1 at 5.

²⁷⁴ D.18-03-023 at 21-22 and OP 4.

²⁷⁵ Ex. SCE-02, Vol. 4, Pt. 1 at 16.

²⁷⁶ *Id.* at 20, Table II-5.

²⁷⁷ Ex. SCE-13, Vol. 4, Pt. 1, at 3, Table I-I.

²⁷⁸ Ex. PAO-07 at 11.

Advocates and TURN recommend capital reductions of \$87.067 million for E&P Tools and \$10.154 million for the GMS over the 2019-2021 period, based on arguments that SCE should be held accountable for cost escalations between rate cases when there is no showing of increased scope or functionality.²⁷⁹ TURN also recommends reductions in spending for distribution automation based on arguments that SCE can achieve similar functionalities and benefits using lower cost Remote-Controlled Switches and Remote Fault Indicators in place of Remote Intelligent Switches.²⁸⁰

12.1.1. Grid Modernization O&M

SCE identifies two areas of Grid Modernization O&M costs: T&D Deployment Readiness and IT Project Support. Each of these areas is described below.

12.1.1.1. T&D Deployment

T&D Deployment Readiness largely consists of organizational change management (OCM) functions to prepare and support SCE employees in implementing the new technologies and operations associated with SCE's GMP. SCE asserts operators and planners will need to evolve their capabilities, learn to use new technology, and embrace new processes, which will be accomplished through detailed impact assessments of the organizations deploying, operating, and maintaining the new Grid Modernization technologies. SCE's TY O&M expense forecast of \$1.539 million for these activities is based on projected non-labor OCM contract expenses.²⁸¹

²⁷⁹ Ex. PAO-05 at 9; Ex. TURN-04 at 6.

²⁸⁰ Ex. TURN-04 at 3.

²⁸¹ Ex. SCE-02, Vol. 4, Pt. 1 at 22-23.

We find reasonable and adopt SCE's uncontested O&M forecast for T&D Deployment Readiness.

12.1.1.2. IT Project Support

IT Project Support includes O&M expenses associated with implementing the E&P software tools, communications, and GMS capital deployments. For each Grid Modernization capital project, this includes the development and delivery of training, IT-related change management, cloud-hosted applications,²⁸² and employee-related expenses. SCE's TY O&M forecast of \$5.734 million for these activities is based on 2018 recorded labor expenses and contract pricing with selected vendors for non-labor IT expenses.²⁸³

Cal Advocates recommends \$3.630 million for IT Project Support, a \$2.104 million reduction from SCE's request. Cal Advocates asserts that SCE's recorded non-labor costs have varied significantly throughout the years, ranging from \$0.864 million in 2016 to \$2.442 million in 2018, and bases its proposal on a three-year average of 2017-2019 (2017-2018 recorded and SCE's 2019 forecast) compared to SCE's itemized non-labor forecast.

In response, SCE argues its forecast is based on actual contractual pricing negotiations, and that Cal Advocates does not provide any actual evidence to support the use of a 2017-2019 average, or take into consideration the associated O&M expenses needed to support SCE's Grid Modernization capital forecast. SCE also asserts there is Commission precedent for using itemized forecasting.²⁸⁴

²⁸² Cloud-hosted applications are software as a service solutions that allow users to access an application remotely from cloud infrastructure via the internet. (*See* Ex. SCE-02, Vol. 4, Pt. 1, at 24, fn. 43.)

²⁸³ Ex. SCE-02, Vol. 4, Pt. 1 at 26.

²⁸⁴ Ex. SCE-13, Vol. 4, Pt. 1 at 63-65.

Cal Advocates does not contest the need for SCE's IT Project Support activities, or question whether previous recorded IT Project Support expenses were prudently incurred. Rather, the sole issue in dispute is whether SCE's forecast methodology is reasonable. In this instance, we find SCE's use of an itemized forecast to be reflective of the expenses that SCE is likely to incur. Whereas SCE's O&M forecast corresponds with the anticipated workstreams stemming from each Grid Modernization capital project, Cal Advocates provides no explanation for why a three-year average better reflects the level of work SCE is expected to perform. Further, we find SCE's projected costs, which are based on market pricing from competitive solicitations, to be reasonable. Therefore, we approve SCE's request of \$5.734 million for IT Project and Support activities.

12.1.2. Grid Modernization Capital

12.1.2.1. E&P Tools

SCE's E&P Tools are used to calculate the level of DERs that can be hosted by the distribution system without triggering the need for infrastructure upgrades, and to forecast SCE's short-term and long-term grid needs.²⁸⁵ Brief descriptions of the individual E&P Tool workstreams are provided below:

- Grid Connectivity Model: A single, centralized software model of SCE's entire electric grid, designed to provide an accurate representation of electrical hierarchy²⁸⁶ and connectivity while supporting enhanced capabilities of other E&P tools and the GMS.²⁸⁷
- Grid Analytics Application: Provides SCE engineers, system planners, and system operators with analytical,

²⁸⁵ Ex. SCE-02, Vol. 4, Pt. 1 at 28.

²⁸⁶ Electrical hierarchy refers to the relationship between various electrically-connected components of the electrical system. For example, the connection between customer meters, to distribution circuits, to substations. (See Ex. SCE-02, Vol. 4, Pt. 1 at 39, fn. 65.)

²⁸⁷ Ex. SCE-02, Vol. 4, Pt. 1 at 39-42.

visualization and decision-support capabilities required to plan and operate a modern grid.²⁸⁸

- Long-Term Planning Tool and System Modeling Tool: Provides forecasting, power system analysis, and work management capabilities that enhance SCE's ability to analyze the grid's capacity to integrate DERs, and of DERs' potential to provide locational net benefits, to support optimal solutions for SCE's short-term and long-term grid needs.²⁸⁹
- Grid Interconnection Processing Tool: A business process management tool that enables customers and SCE to connect generation and load quickly and efficiently to the electric grid.²⁹⁰
- DRP External Portal: An interactive website that provides the public with detailed, up-to-date, and immediate access to information about the ability to connect DERs to SCE's distribution circuit sections.²⁹¹

SCE's E&P Tools retain the same workflow structure established in the 2018 GRC, with one adjustment to combine the Long-Term Planning Tool and System Modeling Tool due to the close inter-dependency of their features and functionalities. SCE states the E&P Tools are necessary to address new Commission compliance requirements in the DRP proceeding and to help resolve limitations with SCE's legacy tools.²⁹² SCE forecasts combined 2019-2021 capital expenditures of \$89.357 million for the E&P Tools, based on vendor solicitation Request for Proposal (RFP) results.²⁹³ SCE's forecast for E&P Tools is

²⁸⁸ *Id.* at 44-45.

²⁸⁹ *Id.* at 47-48.

²⁹⁰ *Id.* at 51-53.

²⁹¹ *Id.* at 55-56.

²⁹² *Id.* at 28-29.

²⁹³ Ex. SCE-13, Vol. 4, Pt. 1, at 3, Table I-1 and Appendix B at B-74 through B-80.

higher than estimated in the 2018 GRC request, which SCE attributes to:
(1) additional requirements that have emerged from the DRP proceeding;
(2) increased deployment complexity; and (3) the maturity and suitability of products currently available in the market.²⁹⁴

Cal Advocates recommends \$1.643 million in combined capital expenditures for E&P Tools over the 2019-2021 timeframe, or a \$87.067 million reduction from (*i.e.*, 97.4 percent of) SCE's request.²⁹⁵ Cal Advocates asserts that SCE's request for E&P Tools has more than doubled since its 2018 GRC request, with no showing of increased scope or functionality; that nearly all of SCE's claimed or new incremental requirements were either signaled by the Commission prior to SCE's TY 2018 GRC application, expressly acknowledged within SCE's TY 2018 testimony/workpapers, or both;²⁹⁶ that SCE's purported impact from E&P Tool product immaturity is unquantified and likely exaggerated; that SCE has not demonstrated it accurately forecasts software tool costs;²⁹⁷ and that in SCE's 2018 GRC decision the Commission limited further E&P Tool funding to SCE's requested 20 percent contingency adder.²⁹⁸ Based on these arguments, Cal Advocates recommends SCE shareholders be held accountable for the cost escalation between rate cases, and that only future "refresh" costs be authorized.²⁹⁹

²⁹⁴ *Id.* at 13.

²⁹⁵ Ex. PAO-05 at 2.

²⁹⁶ Cal Advocates OB at 63-67.

²⁹⁷ *Id.* at 68-70.

²⁹⁸ *Id.* at 61-62.

²⁹⁹ Ex. PAO-05 at 2-3 and 34.

TURN generally supports the analysis provided by Cal Advocates, and recommends no capital funding for the E&P Tools in 2020 and 2021.³⁰⁰ TURN also observes that SCE's proposal seems to be contrary to the Commission's directives in D.19-05-020 to maximize benefits at the lowest cost, and that SCE's Grid Modernization proposal has not been completely scoped out leaving potential opportunities for future cost escalations.³⁰¹ TURN observes the E&P Tools are primarily focused on compliance with Commission directives in the DRP proceeding,³⁰² and in the future recommends the Commission establish a more iterative process in authorizing new DRP requirements that allows for a review of credible information concerning implementation costs.³⁰³

SBUA recommends SCE be directed to re-file its distribution investment plan to align load growth planning with Commission-adopted forecasts for resource planning, and that SCE should shift more funds to the grid modernization functions that focus on facilitating DER deployment.³⁰⁴

In response, SCE asserts it is reasonable for additional funding to be authorized to meet changing regulatory compliance requirements and unanticipated project complexity, and that requiring shareholders to fund the E&P Tools would violate a fundamental regulatory compact which allows utilities the opportunity to earn a reasonable rate of return on prudent capital expenditures.³⁰⁵ SCE highlights the following DRP requirements, which it

³⁰⁰ Ex. TURN-04 at 4-5.

³⁰¹ *Id.* at 3-4 and 7-8.

³⁰² *Id.* at 8.

³⁰³ TURN RB at 10.

³⁰⁴ Ex. SBUA-01 at 5.

³⁰⁵ Ex. SCE-13, Vol. 4, Pt. 1 at 5-6.

asserts are either new or which SCE could not have fully anticipated as part of its TY 2018 GRC request: (1) hourly profiles vs. peak values; (2) analysis to the circuit-segment level versus circuit level; (3) monthly updates to reflect changes by SCE and customers; (4) multiple types of Integration Capacity Analysis (ICA) values; and (5) data redaction.³⁰⁶ SCE also states the completion of multiple competitive solicitations following the 2018 GRC provided a more nuanced understanding of what is required to implement the E&P Tools, leading SCE to conclude that no single vendor solution was available and that multiple, distinct tools would be necessary.³⁰⁷ Finally, SCE asserts that D.19-05-020, addressing SCE's 2018 GRC, did not place any limitations on SCE's ability to request additional funds for the E&P Tools.³⁰⁸

A fundamental issue underlying party arguments is whether SCE should be provided the opportunity to seek increased funding for the E&P Tools when there is no apparent increase in tool functionality or scope. As we have stated elsewhere, ratemaking is not an exact science that guarantees perfect results from all perspectives; rather, it is essentially the art of estimating future events based on judgment that is as fully informed as possible.³⁰⁹ While SCE has the burden to prove that the additional E&P Tools costs are reasonable, the mere occurrence of projected cost increases does not, in and of itself, support a conclusion of unreasonableness, nor is SCE restricted to a single opportunity to establish funding levels for the E&P Tools as Cal Advocates appears to imply.³¹⁰ Rather,

³⁰⁶ SCE RB at 39-46.

³⁰⁷ Ex. SCE-13, Vol. 4, Pt. 1 at 23.

³⁰⁸ SCE RB at 49.

³⁰⁹ See D.85-03-042, 17 CPUC2d 246, at 254.

³¹⁰ Cal Advocates OB at 52.

SCE's request should be judged based on need and whether the projected cost increases appear just and reasonable.

In this instance, there is no dispute regarding the need for the E&P Tools, or that the tools are primarily focused on compliance with Commission directives regarding DER integration and infrastructure investment deferral. We agree that the need for the E&P Tools is well supported and largely driven by DRP compliance requirements.

Regarding whether the cost increases are just and reasonable, we find SCE's arguments to be compelling. SCE attributes part of the E&P Tool cost increase to additional requirements from the DRP proceeding and the associated increase in deployment complexity. The Commission adopted two decisions in R.14-08-013 following the submission of SCE's 2018 GRC application and supporting testimony: D.17-09-026, which addressed methodological ICA and Locational Net Benefit Analysis (LNBA) issues for DRP demonstration projects;³¹¹ and D.18-02-004 which, among other things, required the IOUs to implement DER growth scenarios.³¹² While some of the associated requirements from these decisions may have been signaled or broadly anticipated, other issues were the subject of ongoing dispute (*i.e.*, the use of 576 hourly profiles in the calculation of ICA results)³¹³ or were resolved with greater specificity and clarity than could have been reasonably anticipated at the time (*i.e.*, the disaggregation of load and DER forecasting at the circuit or circuit-segment level and subsequent data redaction requirements).³¹⁴

³¹¹ See D.17-09-026 at 2-3.

³¹² See D.18-02-004 at OP 2a.

³¹³ Ex SCE RB at 41; also, D.17-09-026 at 13.

³¹⁴ SCE RB at 42-46.

More importantly, no party specifically took issue with SCE's 2021 GRC forecast methodology or questioned whether the requested level of funding corresponds to products currently available in the market. SCE's current E&P Tool capital expenditure forecast is primarily comprised of vendor contract, hardware, and software costs stemming from competitive market solicitations.³¹⁵ We have reviewed SCE's capital expenditure forecasts for each of the E&P Tools and believe the methodologies and amounts to be reasonable.

Contrary to Cal Advocates' assertion, SCE's 2018 GRC decision does not limit future E&P Tool funding requests to the 20 percent contingency factor SCE initially requested. Instead, D.19-05-020 highlights, as we note above, that ratemaking is not an exact science, finding that "if additional funds become necessary, then SCE may seek to establish that necessity in the next GRC."³¹⁶ Based on the record before us, we find that SCE has established the need for additional funds, and determine the requested amounts to be reasonable. Therefore, we approve SCE's full 2019-2021 capital expenditure forecast of \$89.357 million for the E&P Tools.

Lastly, we take note of TURN's recommendation to establish a more iterative process in authorizing new DRP requirements that allows for review of credible implementation cost information. While TURN's specific proposal is better addressed through R.14-08-013, we remind parties that, regardless of whether the need for a proposed activity is supported by one or more previous Commission decisions, this does not (and should not) preclude parties or the

³¹⁵ Ex. SCE-02, Vol. 4, Pt. 1, Ch. II – Book A at 123-144.

³¹⁶ See D.19-05-020 at 152.

Commission from examining whether the underlying costs of that activity are just and reasonable.

12.1.2.2. Grid Management System

The GMS is an advanced software platform that will integrate multiple electric system forecasting and analytics applications to enable grid operators to actively monitor and operate SCE's increasingly dynamic grid. The GMS is intended to replace SCE's legacy Distribution Management System and Outage Management System, and includes three primary components: (1) the Advanced Distribution Management System, which will provide real-time information on customer energy usage, system power flows, system outages, faults, and DER performance; (2) the Distributed Energy Resources Management System, which will be used to communicate and interact with DERs; and (3) advanced applications, which include the optimization engine, data historian, device management, adaptive protective system, business rules functionalities, and short-term forecasting. Based on SCE's Benefit-Cost analysis (BCA), SCE estimates the GMS will provide reliability benefits nearly five times greater than its cost.³¹⁷

In the 2021 period, SCE states it will focus on enabling the following GMS capabilities: real-time situational awareness and analysis; power flow optimization; operational planning; assisted and automated switching; interaction with DERs; microgrid management; process improvement through the elimination of paper-based outage and distribution management workflows;

³¹⁷ Ex. SCE-02, Vol. 4E2, Pt. 1 at 75.

resilient design through local and geographical redundancies; and the support of multivendor interoperability.³¹⁸

SCE forecasts \$115.553 million in capital expenditures for the GMS over the 2019-2021 period, based on competitive solicitation results and competitive market pricing.³¹⁹ SCE's capital expenditure forecast for GMS represents a 43 percent increase over its 2018 GRC request, which SCE attributes to: (1) basing the 2021 GRC forecast on the results of a competitive solicitation (as opposed to the 2018 forecast, which was based on internal IT cost estimates); (2) evolving technical solutions and additional project scope for addressing the GMS business requirements; and (3) moving from a three-year to five-year deployment.³²⁰

Cal Advocates and TURN recommend \$106.245 million in capital expenditures for the GMS over the 2019-2021 timeframe, a \$9.208 million reduction from SCE's request.³²¹ Cal Advocates argues that the GMS lacks adequate costs for testing; that the increase in SCE's forecast GMS deployment cost is not due to an increase in GMS functionality;³²² that only 48 percent of the GMS forecast for 2019-2023 is based on competitive solicitation; and that SCE has not substantiated the cost increase associated with extending GMS deployment from three to five years.³²³ Based on these arguments, Cal Advocates recommends total GMS funding (*i.e.*, including prior recorded costs) not exceed

³¹⁸ Ex. SCE-02, Vol. 4, Pt. 1 at 76-78.

³¹⁹ Ex. SCE-13, Vol. 4, Pt. 1 at 3 and 31-32.

³²⁰ *Id.* at 31.

³²¹ *Id.* Table I-1 at 3.

³²² Ex. PAO-05 at 20-31.

³²³ Cal Advocates OB at 87-94.

SCE's TY 2018 GRC request of \$134.5 million,³²⁴ and that SCE be held accountable for providing all functionality described in its testimony. Further, Cal Advocates recommends that future GMS funding be limited to "refresh" costs.³²⁵

TURN generally supports the analysis and recommendations provided by Cal Advocates. In addition, TURN argues funding should be denied on the grounds that SCE's current GMS proposal contains the same projects and business functionalities as authorized in the 2018 GRC; that certain GMS functionalities may be duplicative;³²⁶ and that the decision to extend GMS deployment by two years was entirely within SCE's control and is therefore not a valid justification for increased costs.³²⁷

In response, SCE asserts the Commission has already found the GMS to be just and reasonable; that SCE's GMS costs are supported and justified, as demonstrated through testimony and data responses; that while SCE's current GMS approach includes the same business functionalities as presented in the 2018 GRC, SCE's technical solutions have evolved to include end-to-end testing frameworks, a more robust Data Historian, and business rules functionality³²⁸ (representing 20 percent of the GMS cost increase);³²⁹ that SCE's 2021 forecast for the GMS excludes contingency costs,³³⁰ and, that an extension of GMS

³²⁴ This is the amount requested and approved in SCE's 2018 GRC. (See Ex. PAO-05 at 26.)

³²⁵ *Id.* at 85.

³²⁶ Ex. TURN-04 at 6-7.

³²⁷ TURN OB at 28-29.

³²⁸ Ex. SCE-13, Vol. 4, Pt. 1 at 27-33.

³²⁹ SCE RB at 51-52.

³³⁰ Ex. SCE-13, Vol. 4, Pt. 1 at 34-35.

deployment from three to five years is justified based on the complexity of the deployment and recognition that a three-year deployment would not be possible.³³¹

Similar to party positions regarding SCE's funding request for E&P Tools, a fundamental issue with SCE's GMS request concerns whether SCE should be allowed the opportunity to seek increased funding when there is no apparent increase in tool functionality. We will not repeat our discussion here, but evaluate SCE's request based on need and whether the cost increases appear just and reasonable.

Parties generally do not dispute the need for the GMS. While TURN notes that certain GMS functionalities may be unnecessary or duplicative, stating that "some of the advanced functionalities of the GMS are not necessary or can be achieved by lower cost solutions already present in SCE's other E&P Tools,"³³² TURN's recommendation is more focused on potential cost reductions than the overall need for the GMS itself. As we found in SCE's 2018 GRC, the GMS is expected to provide cybersecurity benefits, enable DERs, and integrate SCE's distribution software,³³³ and we continue to find merit in the implementation of these functionalities.

For the most part SCE's projected costs also appear reasonable. Beyond Cal Advocates' observation that only half of the GMS forecast is based on the results of competitive solicitations, no party disputes any of the specific cost components underlying SCE's GMS forecast, or questions whether SCE's forecast more accurately reflects current market pricing. Parties also do not dispute the

³³¹ *Id.* at 34.

³³² Ex. TURN-04 at 6-7.

³³³ D.19-05-020 at 115.

need or pricing for a more robust Data Historian and business rules functionality, and we find that SCE has provided sufficient documentation to support additional end-to-end testing costs, which addresses Cal Advocates' other criticism that SCE's GMS forecast lacks adequate costs for testing. We have reviewed the underlying costs for SCE's GMS forecast³³⁴ and largely find the amounts to be well-supported and reasonable.

We do not, however, find that SCE has met its burden of proof in demonstrating why GMS deployment should be extended from three to five years. As noted by Cal Advocates and TURN, the decision to extend GMS deployment by two years was entirely within SCE's control. SCE provides little evidence to support the extension beyond a general assertion that the extension was made in "appreciation of the complexity of deployment and a recognition that a three-year deployment would not be possible."³³⁵ At a minimum, SCE should have identified the specific complexities driving the need for the extension, the cost impact associated with the proposed extension, and whether other timelines and associated cost impacts were considered. Therefore, we approve \$110.553 million in capital expenditures for the GMS over the 2019-2021 period, including a \$5 million reduction from SCE's request to account for the two-year extension of labor costs.

12.1.2.3. Automation

SCE's request for automation capabilities is intended to help integrate higher amounts of DERs while addressing reliability challenges on SCE's worst performing circuits. SCE explains that while the electric grid has traditionally

³³⁴ Ex. SCE-13, Vol. 4C, Pt. 1, Appendix B at B47-B67; Ex. PAO-22C at 167-168.

³³⁵ Ex. SCE-13, Vol. 4, Pt. 1 at 34.

operated as a one-way system, increasing DER adoption has resulted in bi-directional power flow, masked loads, and resource variability, and that automaton will provide system operators with additional visibility, situational awareness, and control.³³⁶ SCE also asserts the additional visibility will improve potential switching options during abnormal or fault conditions, reducing sustained customer outages by a projected 50-75 percent on SCE's worst performing circuits.³³⁷ SCE's current Grid Modernization Automation request is similar to its 2018 GRC request, but at a much more limited scope and pace due to SCE's reallocation of resources to mitigate wildfire risk.³³⁸

SCE's Grid Modernization Automation activities are comprised of Reliability-Driven Distribution Automation; DER-Driven Distribution Automation; Small Scale Deployments; Reliability-Driven Substation Automation; and DER-Driven Substation Automation.³³⁹ These programs are briefly described below.

- Reliability-Driven Distribution Automation (RDA): Consists of grid sensors, Remote Fault Indicators, Remote-Controlled Switches, and Remote Intelligent Switches installed on the distribution grid to facilitate Fault Location Isolation and System Restoration (FLISR).³⁴⁰ This program is designed to address uncontrollable outages, quicken

³³⁶ Ex SCE-02, Vol. 4, Pt. 1 at 82-83.

³³⁷ *Id.* at 90-92.

³³⁸ *Id.* at 86.

³³⁹ Ex. SCE-13, Vol. 4, Pt. 1, Table II-6 at 40.

³⁴⁰ FLISR is intended to reduce the impact of an outage by detecting when a system fault occurs, isolating the faulted section, and restoring customer load. (See Ex. SCE-02, Vol. 4, Pt. 1, at 72, fn. 129.) The FLISR works together with switches, which are devices capable of dividing contiguous circuit segments. (*Id.* at 90, fn. 150.) Installing additional switches per circuit can increase reliability since more customers can be switched off the affected circuit, thus reducing the customer minutes of interruption. (See Ex. SCE-02, Vol. 2, Pt. 1, Ch. II – Book A at A-6 through A-7.)

outage response times, reduce the impact of equipment failures, and mitigate outages related to DER integration challenges.³⁴¹

- DER-Driven Distribution Automation: Consists of remote fault indicators (RFIs) installed on distribution circuits with high levels of DER penetration and that have corresponding reliability degradation as identified by SCE's DER Grid Reinforcement Study. This program is designed to mitigate potential degradation and help accommodate forecasted DER growth.³⁴²
- Small Scale Deployments: Includes pilots of limited quantities of distribution automation components across SCE's various geographic regions prior to large-scale deployment. This program is intended to validate the functionalities of the components in different operating environments and help inform the training and skillsets required to plan, install, and operate these technologies at a larger scale.³⁴³
- Reliability-Driven Substation Automation: Consists of upgrading substations with a high risk of relay failures to a modern substation automation design standard (SA-3). In contrast to historical automation systems, which require manual configuration at the substation to function properly, SA-3 enables SCE to change substation safety settings using cyber-secure, internet-based communications.³⁴⁴
- DER-Driven Substation Automation: In addition to enabling internet-based communications, SA-3 can monitor reverse power flow and dynamically adjust protection settings. Deploying SA-3 in areas with high DER penetration is expected to reduce the number of improper

³⁴¹ Ex. SCE-02, Vol. 4, Pt. 1 at 96 and Appendix A at A-49.

³⁴² *Id.* at 106 and Appendix A at A-50.

³⁴³ *Id.* at 108.

³⁴⁴ *Id.* at 89 and 113; also, Ex. SCE-02, Vol. 4, Pt. 1, Ch. II – Book A at 91.

substation circuit breaker operations and improve reliability.³⁴⁵

Overall, SCE requests combined capital expenditures of \$123.443 million during 2019-2021 for all Grid Modernization Automation activities. The capital forecast for RDA (\$94.027 million) is based on recorded 2019 expenses and future automation of an estimated seventy-five distribution circuits per year using historic unit costs;³⁴⁶ the forecast for DER-Driven Distribution Automation (\$1.615 million) is based on historic RFI unit costs and the deployment of RFIs on 70 circuits during the 2021 GRC period;³⁴⁷ the forecast for Small Scale Deployments (\$15.185 million) is based on unit costs of existing and similar automated technologies funded through the Electric Program Investment Charge (EPIC) balancing account and small-scale deployment;³⁴⁸ the forecast for Reliability-Driven Substation Automation (\$8.616 million) is based on recorded 2019 expenses (SCE does not propose to initiate new Reliability-driven Substation Automation work beyond 2019);³⁴⁹ and the forecast for DER-Driven Substation Automation (\$4 million) is based on upgrading ten distribution substations over the GRC period and recent SA-3 conversion unit costs.³⁵⁰

With the exception of RDA, all of SCE's Grid Modernization Automation activities are uncontested. We find reasonable and approve SCE's uncontested

³⁴⁵ Ex. SCE-02, Vol. 4, Pt. 1, Ch. II – Book A at 100.

³⁴⁶ Ex. SCE-02, Vol. 4, Pt. 1 at 104-106; Ex. SCE-02, Vol. 2, Pt. 1, Ch. II – Book A at 174-176; Ex. SCE-13, Vol. 4, Pt. 1 at 40; Ex. SCE-54 at 133.

³⁴⁷ Ex. SCE-02, Vol. 4, Pt. 1 at 107-108.

³⁴⁸ Recorded 2019 costs of \$0.406 million calculated by subtracting the 2019 recorded costs for RDA (\$35.346 million) and reliability drive substation automation (\$8.616 million) from the total automation budget (\$44.368 million). (*Id.* at 110; Ex. SCE-18, Vol. 1 at A-93.)

³⁴⁹ *Id.* at 112; Ex. SCE-13, Vol. 4, Pt. 1 at 40.

³⁵⁰ Ex. SCE-02, Vol. 4, Pt. 1, Ch. II – Book A at 205.

capital forecast for DER-Driven Distribution Automation, Small Scale Deployments, Reliability-Driven Substation Automation, and DER-Driven Substation Automation in the amount of \$29.416 million (2019-2021).

12.1.2.4. Reliability-Driven Distribution Automation

As noted above, RDA is intended to address the impact of uncontrolled outages, quicken outage response times, reduce the impact of equipment failures, and mitigate outages related to DER integration challenges. These benefits are largely achieved through the deployment of additional switches on a circuit. SCE's 2019-2021 capital forecast for RDA is \$94.027 million, which is approximately 76 percent of SCE's combined forecast for all Grid Modernization Automation activities.

In support of its RDA request, SCE contracted with Nexant to conduct a Value of Service (VOS) study to evaluate how much SCE's customers value reliability, measured as how much customers value a customer minute of interruption (CMI). SCE then incorporated the CMI value in a benefit-cost analysis (BCA) in determining that the RDA investments it proposes in this GRC are expected to provide reliability benefits that exceed their cost by a factor of nearly seven.³⁵¹

SCE's BCA also included two additional dimensions: the type of automation (denoted by switch type) and the automation scheme. There are three types of automation switching: Remote Switching, where system operators process raw data and take any necessary actions; Assisted Switching, where the GMS provides the system operator with switching recommendations based on real-time grid information; and Automated Switching, where the GMS derives

³⁵¹ *Id.* at 87.

the preferred switching procedure and acts under the supervision of the system operator. SCE's preferred option is to employ Assisted Switching using Remote Intelligent Switches (RISs), which also corresponds with a high Benefit-Cost ratio. There are four options for the automation scheme: 1:1, 2:2, 3:3, and +1:+1. 1:1 refers to a circuit with one midpoint switch and one circuit tie switch, 2:2 refers to a circuit with 2 midpoint switches and 2 circuit tie switches, and so forth. The +1:+1 refers to adding one additional midpoint switch and one additional circuit tie switch to a circuit, irrespective of the current number of midpoint and circuit tie switches.³⁵²

12.1.2.4.1. TURN

TURN recommends \$18.609 million for RDA during the 2020-2021 period, which is a reduction of \$40.073 million from SCE's request.³⁵³ TURN's proposal is based on two main arguments: first, TURN asserts the reliability benefits of SCE's RDA investments are overstated. Second, TURN asserts SCE should prioritize the installation of remote-controlled switches (RCSs) and RFIs on the basis that they are relatively inexpensive and more cost-effective than RISs and additional circuit ties.³⁵⁴

³⁵² Ex SCE-13, Vol. 4, Pt. 1 at 46 and Appendix A at A7.

³⁵³ TURN OB at 27.

³⁵⁴ RCSs are a type of switch that can be controlled remotely by system operators but that does not collect circuit data (known as telemetry), while RFIs allow system operators to remotely direct troublemen closer to the location of the fault with additional manual switching. (See Ex. TURN-04 at 10-11.)

In contrast, RIS or smart switches collect and transmit real-time information (*e.g.*, current strength, direction, etc.), which allows for point-to-point communication with the GMS to execute a switching plan in real time. (*Ibid.*) A circuit tie is a pathway through which power can be re-routed from one circuit to another during emergency events or planned maintenance. (See Ex. SCE-02, Vol. 4, Pt. 1 footnote 152 at 90.) The RIS requires a circuit tie to provide switching-related functionality. (See Ex. TURN-04 at 15.)

While TURN accepts the need to use a VOS study to monetize reliability benefits, TURN argues there are several shortcomings in a VOS study itself, including: (1) the potential presence of survey bias (also referred to as “non-response bias”), whereby customers who are more likely to have a higher VOS are also more likely to participate in the survey; (2) lack of distinction in using VOS results between different customer classes, which obscures the fact that residential customers value reliability significantly less than small business or commercial and industrial (C&I) customers; (3) a potential overestimate of system-wide benefits by modeling CMI using historical outage data then spreading the estimated benefits evenly across the grid; and (4) lack of consideration of customer-owned generation and storage as reliability back-up methods.³⁵⁵

Second, TURN asserts that deploying RCSs and RFIs in place of RISs and/or more circuit ties would achieve similar functionalities more cost-effectively. Using SCE’s BCA for remote switching, TURN replaced the cost of RISs with the cost of RCSs and increased the expected reliability benefits from improved GMS functionality. TURN’s revised analysis indicates the Benefit-Cost ratio for remote switching is almost always higher (by 5-20 percent) due to the lower cost of the RCS. Based on these results, TURN recommends the Commission set a forecast that is comparable to the cost of RCS switches assuming the switch count in SCE’s forecast.³⁵⁶ TURN also recommends the Commission authorize a level of replacement vaults for certain circuit tie upgrades commensurate with the ratio of circuits approved in the 2018 GRC

³⁵⁵ Ex. TURN-04 at 19-23.

³⁵⁶ *Id.* at 11-13.

(*i.e.*, 110 circuits out of 600 requested), based on an assertion that circuit tie upgrades are an expensive way to achieve reliability.³⁵⁷

Finally, while SCE has reduced its forecast for RDA over this rate case cycle, as compared to its 2018 GRC request, TURN observes that the full cost of automation over the course of SCE's 10-year Grid Modernization Plan is projected to be over \$2 billion.³⁵⁸ To the extent SCE includes additional distribution automation requests in future GRCs, TURN recommends that SCE be directed to: (1) show the incremental benefits of adding more switches and ties to a circuit are greater than the incremental costs of the investments; (2) compare the costs and benefits of using RISs to improve reliability against costs and benefits of using RCSs; and (3) identify each specific circuit tie that is intended to be installed or upgraded (rather than using a simple average costs and unit counts) and demonstrate the cost-effectiveness of each against reasonable alternatives.³⁵⁹

12.1.2.4.2. SCE Reply

In reply, SCE asserts that TURN's critiques of the VOS study are inaccurate for the following reasons: (1) while it is impossible to eliminate all sources of survey error, SCE states that Nexant found no difference between the distribution of observable characteristics among survey respondents and the overall customer population, which could have indicated the presence of non-response bias. Further, SCE highlights that the weighted average usage of respondents is 1 percent lower than the population average usage, suggesting survey respondents may value reliability on par with, or below, the overall

³⁵⁷ Ex. TURN-04E at 13-14; TURN OB at 38.

³⁵⁸ Ex. TURN-04 at 2-3.

³⁵⁹ *Id.* at 24.

population; (2) SCE states the VOS study used a weighted average to reflect the mix of residential and non-residential customers served by SCE; (3) SCE asserts the BCA accounts for other programs that target reliability; and (4) SCE states the VOS survey explicitly asked customers about back-up power and that Nexant included this information in the outage cost calculation.³⁶⁰

Regarding TURN's modified BCA calculations, SCE asserts there are two erroneous assumptions in TURN's analysis: first, TURN assumes, without explanation, that the GMS will increase the switching speed of remote switching by approximately 11 minutes. SCE asserts the 11-minute improvement is entirely speculative. Second, SCE points to the assumption in TURN's analysis that RCSs could be used to perform Remote Switching for all the distribution schemes included in SCE's original analysis. SCE asserts that this is not the case, since it would require operating the grid in a manner that is prohibited by SCE's current operating procedures. SCE explains that it relies on circuit breaker testing and measurements to inform additional RCS switching to restore load, which involves injecting fault current (up to a maximum of two times) into the circuit. By adding additional midpoint switches SCE would need to increase the number of tests currently allowed per fault, which SCE asserts would introduce safety risk and negatively impact asset health. SCE adjusted TURN's BCA analysis to cap the benefits at the amounts forecasted and remove GMS-related process improvements: the result is that SCE's proposed Assisted Switching scenario provides a Benefit-Cost ratio that is 40 percent higher under the +1:+1 scheme than TURN's Remote Switching scenario.³⁶¹

³⁶⁰ Ex. SCE-13, Vol. 4, Pt. 1 at 41-45.

³⁶¹ *Id.* at 46-54.

Lastly, SCE clarifies that it is not seeking to install new circuit ties, but rather its request is for replacement vaults for certain circuit ties where the existing vault is not sufficient to accommodate the new RDA switches. SCE asserts these upgrades are necessary to accommodate the additional automated switches that SCE is pursuing in this GRC period and to realize the reliability improvements forecasted in SCE's BCA.³⁶²

12.1.2.4.3. Discussion

Parties generally dispute the value of, and estimated benefits from, automated distribution switching, and whether that value is appropriately reflected through the VOS study and SCE's BCA. We find that SCE has sufficiently addressed most of TURN's specific criticisms concerning the VOS study. While it is possible that the VOS study contains survey non-response bias, we agree with SCE that the direction of the bias cannot be assumed in one way or another. Further, VOS survey respondents appear to be reasonably representative of SCE's mix of customers in terms of business type, usage, and location. SCE has also sufficiently explained how the use of an average CMI value accounts for other programs that target reliability, and that the VOS study accounts for backup power resources.

However, TURN's argument that the VOS masks the value per CMI that different customer classes ascribe to service reliability is well taken, with C&I customers placing a value on reliability (\$714/CMI) several magnitudes higher than that of residential customers (\$0.07/CMI).³⁶³ While the VOS study has been weighted to reflect the mix of residential and non-residential customers served

³⁶² *Id.* at 54-56.

³⁶³ Ex. TURN-04 at 20.

by SCE, given the significant level of capital expenditures approved in this decision, we do not lose sight of the potential affordability impacts stemming from a proposed activity that has only marginal value to the average residential customer. Rather than using a weighted average across SCE's system, a more transparent and equitable approach would be to apply the BCA to individual circuits or circuit segments, taking into consideration the associated cost and types of customers (*i.e.*, corresponding CMI values) that would benefit from additional automation. This approach would further inform the potential value of automating SCE's worst performing circuits, and allow circuits to be ranked by BCA according to cost and customer mix. We note that this approach also appears consistent with TURN's recommendation for SCE to demonstrate, in future RDA requests, that the incremental benefits of adding more switches and ties to a circuit is greater than the incremental costs of those investments.

Regarding TURN's proposal to deploy RCSs and RFIs in place of RISs, the potential safety and asset degradation impacts that could result from additional midpoint switches under TURN's proposal are concerning. SCE does not quantify the potential impact of multiple current injections on distribution asset life, and there is limited record in this proceeding concerning the potential safety issues associated with TURN's RCS/RFI-only approach. While it is unclear, based on the record before us, whether there are other lower-cost options that could safely support distribution automation, we are not convinced TURN's proposal could be implemented safely or that it is in the best interest of ratepayers. Concerning TURN's related proposal to limit circuit tie upgrades (which are required for RISs to provide switching-related functionality), beyond

claiming that these upgrades are “an expensive way to increase reliability”³⁶⁴ and referencing arguments made in SCE’s previous GRC, TURN does not provide any evidence to support its claim. Given the limited argument provided on this issue we find no reason to make a reduction to SCE’s request for replacement vaults.

Notwithstanding our finding that SCE’s BCA would benefit from more granular, circuit-level analysis, we approve SCE’s full 2019-2021 RDA capital expenditure request of \$94.027 million. Due to the temporary reallocation of resources to mitigate wildfire risk, SCE’s RDA request over this GRC period is less than half of the annual RDA-related funding the Commission approved in SCE’s last GRC (approximately \$31 million per year compared to \$64.675 million per year).³⁶⁵ Given the much more limited scope of SCE’s current distribution automation request, we find SCE’s forecast strikes an appropriate balance between the need for ongoing reliability improvements to SCE’s worst performing circuits and the associated costs of RDA. However, prior to SCE’s next GRC request, we direct SCE to hold one or more technical workshops to: (1) identify each circuit or circuit segment on which SCE intends to deploy RDA, along with the corresponding benefit-cost analysis (ranked by cost and associated CMI value); (2) further evaluate the costs and benefits, as well as the potential safety and asset degradation impacts, associated with an RCS/RFI-only approach; and (3) discuss any other alternatives that might achieve the same or similar automation functionalities at a lower cost. SCE shall coordinate with

³⁶⁴ TURN OB at 37-38.

³⁶⁵ See D.19-05-020 at 109-111.

Energy Division staff in developing the agenda for the technical workshop(s) to ensure that different stakeholder perspectives are incorporated.

12.1.2.5. Communications

SCE identifies the following four components of a new communications system that will enable SCE to communicate cyber-securely and in real-time between grid devices (including DERs), distribution substations, and SCE operation control centers:

- Field Area Network (FAN): A new wireless radio network that will replace SCE's existing NetComm system connecting distribution substations and distribution automation devices. SCE states the new FAN system will incorporate modern cybersecurity capabilities while reducing real-time information transfer delays. SCE projects FAN deployment to conclude in 2028.³⁶⁶
- Distribution System Efficiency Enhancement Program (DSEEP): The DSEEP is intended to ensure grid services continue to communicate with SCE operations control centers prior to the completion of FAN deployment. Activities include the replacement of aging portions of the existing NetComm network and damaged or failed radios.³⁶⁷
- Common Substation Platform (CSP): A computing platform (hardware and software) that acts as the communication and control hub between the operations control center, substation equipment, and distribution automation devices. The CSP enables remote and automatic control over circuit devices.³⁶⁸

³⁶⁶ Ex. SCE-02, Vol. 4, Pt. 1 at 65-66 and 68.

³⁶⁷ *Id.* at 68.

³⁶⁸ *Id.* at 70-71.

- Wide Area Network (WAN): Communications hardware necessary to transmit data from the FAN and substations to SCE's control operations.³⁶⁹

SCE forecasts \$101.313 million in capital expenditures for Grid Modernization communications over the 2019-2021 period. SCE derived the FAN and CSP forecasts based on the results of competitive solicitations; the DSEEP forecast is based on the number of NetComm radios needed to accommodate new automation devices as well as historical costs for installing/replacing radios; and the WAN forecast is based on known costs from similar fiber optic deployments.³⁷⁰

We find reasonable and adopt SCE's uncontested capital expenditure forecast of \$101.313 million for Grid Modernization communications.

12.1.2.6. Subtransmission Relay Upgrade Project³⁷¹

SCE requests capital expenditures for a pilot to replace legacy 66 kW and 115 kW protection relay devices on the Viejo subtransmission system with new relays capable of detecting two-way power flows. SCE indicates the replacement of these relays is being driven by DER penetration, and the ability to measure power flow direction at the substation relays provides an opportunity for SCE's GMS to co-optimize the subtransmission and distribution systems using Conservation Voltage Reduction principles, which could allow SCE to reduce customer energy costs through reduced energy losses on SCE's system, without requiring a change in customer behavior. SCE has already started the project

³⁶⁹ *Id.* at 73.

³⁷⁰ *Id.* at 67, 69-70 and 72.

³⁷¹ Also referred to as DER Hosting Capacity Reinforcement.

and expects construction to be completed in the 2021 GRC period.³⁷² SCE's 2019-2021 capital expenditure forecast of \$1.627 million for the Subtransmission Relay Upgrade Project is uncontested.³⁷³ We find reasonable and approve SCE's uncontested forecast for this pilot.

12.2. Grid Technology Assessments, Pilots and Adoption

SCE's Grid Technology organization was formed in 2009 to identify and assess emerging technologies that could better serve customer needs and comply with state and federal policies while maintaining grid safety and reliability. The organization also provides a means to test newer versions of existing technologies when replacing equipment that has reached the end of its lifecycle. SCE first tests a technology's performance under controlled conditions where service reliability and safety are not impacted, then pilots the technology in a real, integrated grid environment prior to larger scale deployment.³⁷⁴

12.2.1. Grid Technology Capital

SCE currently maintains and operates three facilities to test new technologies: the Westminster Test Facility in Westminster; the Pomona Test Facility in Pomona; and the Equipment Demonstration and Evaluation Facility (EDEF) also located in Westminster. The Westminster Facility supports technology evaluation, proof-of-concept validations, and pre-deployment testing, and includes testing of technologies that support grid communications and cybersecurity, substation and distribution automation, and protection equipment. The Pomona Facility tests and evaluates alternative fuel and electric

³⁷² Ex. SCE-02, Vol. 4, Pt. 1 at 115-121.

³⁷³ Ex. SCE-13, Vol. 4, Pt. 1, at 3, Table I-I.

³⁷⁴ Ex. SCE-02, Vol. 4, Pt. 1 at 122-125.

vehicles, fleet vocational equipment (auxiliary support equipment SCE's utility crews utilize on a jobsite), battery storage components, and electric charging infrastructure. EDEF performs evaluations of emerging technologies in a high-voltage grid environment as well as immediate operational concerns, such as integrating intelligent sensors, communications devices, solar inverters, and energy storage.³⁷⁵

In consideration of future Transportation Electrification capabilities and needs, SCE states it plans to integrate a new Energy Storage and Transportation Electrification (ES&TE) Test Facility within the existing Westminster Test Facility. SCE compared the costs of expanding the Westminster Test Facility against updating the Pomona Facility with similar high-voltage testing capabilities and found expansion of the Westminster Test Facility to be more cost effective. SCE states the Pomona Test Facility will be decommissioned upon the completion of the Westminster ES&TE expansion.³⁷⁶

SCE's combined Grid Technology capital expenditure forecast for its testing facilities is \$9.128 million over the 2019-2021 period. There are no 2019-2023 capital expenditures forecast for the Pomona Facility, as all associated upgrade costs have been integrated into the Westminster Test Facility. Costs for the Westminster Test Facility were developed using existing contracts, recent purchases, and accounting/engineering estimates. In addition to the ES&TE expansion, SCE's forecast includes adding capabilities and making improvements to test spaces; performing hardware refresh updates; and developing new test infrastructure. SCE's forecast for the EDEF includes the

³⁷⁵ *Id.* at 133-134.

³⁷⁶ *Id.* at 134-135.

addition of new test asset hardware based on existing contracts, recent purchases, and accounting/engineering estimates.³⁷⁷

SCE's capital request for Grid Technology is uncontested. In prior GRCs, the Commission has disallowed either all or a portion of SCE's request for upgrades to the Westminster Lab and EDEF on the basis that SCE failed to demonstrate the technical problems these facilities would address are unique to SCE, or that other more cost-effective options do not exist for doing such research.³⁷⁸ Consistent with D.15-11-021, we continue to consider whether the facilities would address problems that are unique to SCE, and that other more cost-effective options do not exist for doing this research.

We have reviewed the proposed research projects at Westminster Lab, and agree that the specific projects SCE proposes to research over this GRC period concern issues that are both relevant and unique to SCE.

Regarding the EDEF, SCE states it conducted an RFP to determine the market cost for providing desired EDEF testing capabilities, and that only one vendor was able to perform most, but not all, of the capabilities SCE is seeking. Further, SCE's cost comparison analysis demonstrates that upgrading the EDEF and performing in-house testing would cost 7.2 percent less than outsourcing the same scope of work to a third-party test facility.³⁷⁹ We have reviewed the specific projects for the EDEF and find they similarly address problems that are unique to SCE. Further, the results of SCE's RFP process reasonably demonstrate that upgrading the EDEF and performing in-house testing costs is the most cost-effective option for meeting SCE's current research needs. Therefore, we

³⁷⁷ *Id.* at 137-146.

³⁷⁸ See D.15-11-021 at 48-50 and D.19-05-020 at 329-332.

³⁷⁹ Ex. SCE-02, Vol. 4, Pt. 1 at 146-149.

authorize SCE's uncontested Grid Technology capital expenditure forecast of \$9.128 million over the 2019-2021 period.

12.2.2. Grid Technology O&M

SCE's Grid Technology O&M activities include: (1) using technology to perform advanced systems studies and develop models to better understand grid operations; (2) operating and maintaining integrated test facilities with the capability to safety test and evaluate new technologies; (3) support for the development of industry standards that promote equipment operability, vendor diversity, and long-term asset deployment strategies; and (4) support for SCE's DRP, as well as support for the Commission's Energy Storage Mandate.³⁸⁰ SCE asserts these activities play a vital role in evaluating promising technologies in a test facility setting.³⁸¹

SCE's 2021 TY O&M request for Grid Technology is \$12.935 million.³⁸² Labor expenses, which include payroll for engineers and management, were derived using a five-year average of recorded 2014-2018 expenses. Non-labor costs, which include allocated overheads, small tools, equipment, and test facility operation/maintenance costs, were also derived using a five-year average of recorded 2014-2018 expenses.

Cal Advocates recommends \$12.230 million for the 2021 TY.

Cal Advocates does not oppose SCE's non-labor forecast, but recommends excluding 2017 when calculating the average of labor expenses on the basis that the level of expense in 2017 was significantly higher than any other year.

³⁸⁰ The Energy Storage Mandate requires SCE to procure and build 580 megawatts of energy storage by 2020 and bring it online by 2024. (See D.13-10-040.)

³⁸¹ Ex. SCE-02, Vol. 4, Pt. 1 at 128-129.

³⁸² Ex. SCE-13, Vol. 4, Pt. 1, at 4, Table I-2.

Instead, Cal Advocates uses the 2019 forecast as part of the five-year average of historical expenses.³⁸³

SCE asserts the purpose of using an averaging methodology in GRC forecasting is to take into account significant fluctuations in expenses, and highlights that Cal Advocates does not claim 2017 expenses were not reasonably incurred, or otherwise argue that customers did not benefit in some manner from the activities. Further, even if Cal Advocates' calculation method were valid, SCE argues that Cal Advocates applies its method in an inconsistent manner.³⁸⁴

The Commission has found that, when accounts reflect significant spending fluctuations from year to year, and in the absence of information to the contrary, the use of a multi-year average of recorded data is expected to yield a more reliable forecast. We agree, and it is undisputed in this proceeding, that a five-year average is appropriate in this instance. Cal Advocates does not provide any explanation for why 2019 forecast data should be substituted for 2017 recorded data beyond highlighting that the expense level in 2017 is higher than any other year (it is \$1.798 million above the second highest level of recorded expenses).³⁸⁵ The year-to-year variation in expenses, including higher 2017 costs, is precisely why the use of a five-year average is appropriate. Without further justification demonstrating that 2017 expenses were atypical, we find SCE's 2014-2018 average to be reasonable. SCE's 2021 TY O&M request of \$12.935 million for Grid Technology is approved.

³⁸³ Ex. PAO-07 at 12-13.

³⁸⁴ Ex. SCE-13, Vol. 4, Pt. 1 at 76-77.

³⁸⁵ *Id.* at 78, Table III-16.

12.3. Energy Storage

SCE requests capital and O&M funding to support two energy storage programs over the GRC period: (1) the Distributed Energy Storage Integration (DESI) pilot systems, and (2) the Mira Loma Energy Storage Systems.

The DESI pilot is focused on evaluating new capabilities enabled by energy storage systems connected to the distribution system and validating associated benefit streams.³⁸⁶ In addition to learning that is aligned with the Commission's Energy Storage Guiding principles,³⁸⁷ SCE states the DESI pilots support the development of (1) integration processes and procedures and (2) validation of the ability of energy storage to serve grid operations functions.³⁸⁸ In the 2018 GRC, the Commission approved funding for SCE to build 13 DESI pilots (including two pilots approved in the 2015 GRC). SCE indicates that two of the pilots have since been cancelled due to land constraints and changing grid needs; however, SCE anticipates being able to extract the originally planned lessons learned and value from the remaining pilots.³⁸⁹ In the 2021 GRC cycle, SCE will continue to deploy the pilots as approved in the 2018 GRC, with the expectation that all pilots will be operational by 2021.³⁹⁰ SCE requests O&M expenses of \$1.413 million in the 2021 TY to support planning and operation phases of the DESI pilots. SCE's forecast is based on approved purchase orders, quotes and established pricing with two vendors, recent project

³⁸⁶ Ex. SCE-02, Vol. 4, Pt. 1 at 150 and 156.

³⁸⁷ See D.17-04-039.

³⁸⁸ Ex. SCE-02, Vol. 4, Pt. 1 at 156.

³⁸⁹ *Id.* at 154 and 166.

³⁹⁰ *Id.* at 175.

costs, and accounting engineering estimates.³⁹¹ SCE also requests \$31.903 million in capital expenditures for the DESI pilots over the 2019-2021 timeframe.³⁹²

SCE's capital expenditure forecast is based on quotes and established pricing with two vendors, recent project costs, and accounting/engineering estimates.³⁹³

The Mira Loma Energy Storage Systems consist of two Tesla battery systems procured to help address reduced operability of the Aliso Canyon gas storage facility.³⁹⁴ Pursuant to D.18-06-009, SCE is authorized to record the revenue requirements for the Mira Loma Energy Storage Systems in the approved Aliso Canyon Energy Storage Balancing Account until cost recovery could be transitioned to base rates as part of SCE's 2021 GRC.³⁹⁵ SCE forecasts \$431 thousand in O&M TY 2021 expenses for the Mira Loma Energy Storage systems, based on existing contractual fixed fees, variable performance fees, and transmission interconnection fees.³⁹⁶

As described above, the Commission has already found reasonable the underlying need for the DESI and the Mira Loma energy storage projects. Further, no party opposed SCE's capital expenditure or O&M forecasts for these programs. We find reasonable and approve SCE's uncontested 2019-2021 capital expenditure and TY O&M forecasts for the DESI pilots. Similarly, we find reasonable and approve SCE's uncontested TY O&M forecast for the Mira Loma Energy Storage Systems.

³⁹¹ *Id.* at 159 and 161-163.

³⁹² Ex. SCE-13, Vol. 4, Pt. 1, at 79, Table IV-17.

³⁹³ Ex. SCE-02, Vol. 4, Pt. 1 at 175.

³⁹⁴ *Id.* at 150-151.

³⁹⁵ See D.18-06-009 at Conclusion of Law (COL) 2.

³⁹⁶ Ex. SCE-02, Vol. 4, Pt. 1 at 164.

13. Load Growth, Transmission Projects, and Engineering

Exhibit SCE-02, Vol. 4, Pt. 2 and Exhibit SCE-13, Vol. 4, Pt. 2 contain SCE's capital expenditure forecasts to support load and DER growth, transmission grid reliability, and renewable generation, as well as SCE's Engineering O&M forecast to support system modifications/expansions and to address customer-reported concerns with power quality.³⁹⁷ Distribution and subtransmission projects are detailed in SCE's Load Growth testimony, while transmission projects are covered in SCE's Transmission Projects testimony.

SCE forecasts combined TY O&M expenses of \$12.757 million for Engineering O&M, combined 2019-2021 capital expenditures of \$1.029 billion for Load Growth, and combined 2019-2021 capital expenditures of \$1.444 billion for Transmission Projects.³⁹⁸

Cal Advocates recommends a reduction of \$0.205 million to SCE's non-labor forecast in Engineering O&M. Cal Advocates also recommends all 2021-2023 DER-Driven Load Growth capital expenditures be tracked in a memorandum account (representing a \$43.035 million reduction to the Load Growth forecast SCE presented in direct testimony), which SCE accepts in rebuttal testimony.³⁹⁹

SEIA and Vote Solar provided testimony concerning refinement of the PV Dependability methodology used in SCE's Load Growth forecast.⁴⁰⁰ Following the submission of rebuttal testimony, SCE and SEIA/Vote Solar reached a

³⁹⁷ Ex. SCE-02, Vol. 4, Pt. 2 at 1, 4 and 103.

³⁹⁸ Ex. SCE-13, Vol. 4, Pt. 2, at 3, Table I-1 at 3 and 4, Table I-2.

³⁹⁹ Ex. PAO-05 at 15-16; Ex. SCE-13, Vol. 4, Pt. 2 at 10.

⁴⁰⁰ Ex. SVS-01.

settlement agreement which would resolve all outstanding issues between these parties, and which we approve in Section 52.1.

SBUA recommends SCE be directed to withdraw its application and to resubmit it with updated forecasts to reflect the economic impacts from COVID-19. SBUA also provides several other recommendations, including that SCE revise and refile its distribution investment plan, that an audit be conducted of SCE's spending, that the Commission "freeze all but essential utility investment," and that SCE only recover the costs of distribution assets on a "percent of utilization" basis.⁴⁰¹

13.1. Load Growth

The Load Growth Business Planning Element (BPE) covers the capital expenditures needed to support customer load and DER growth throughout SCE's electrical grid. The first step in SCE's distribution and subtransmission planning process is to develop 10-year peak load and high DER forecasts for all distribution circuits, distribution substations, subtransmission lines, and load-serving transmission substations. For both peak load and high DER output scenarios, SCE then develops a 10-year load growth forecast at the distribution circuit level using the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) load growth forecast. Finally, SCE performs technical studies to determine whether the projected forecasts can be accommodated by SCE's existing electric grid based on equipment loading limits. When studies show that peak load or DER impacts are expected to exceed planned loading limits, SCE identifies potential solutions to mitigate the risk of

⁴⁰¹ Ex. SBUA-01 at 4-5.

overloading equipment.⁴⁰² In addition to distribution circuit upgrade projects, system improvements may also arise due to local reasons, including changes in load profiles that drive localized voltage problems, instances where new protection devices and switches are needed for safety and reliability, or new residential developments.⁴⁰³

SCE's 2019-2021 capital expenditure request for the Load Growth BPE encompasses programs within the following groups: Distribution Substation Plan (\$618.229 million); DER-Driven Grid Reinforcement (\$0);⁴⁰⁴ Transmission Substation Plan (\$269.903 million); System Improvement Programs (\$137.752 million); and Land Rights Management (\$3.027 million).⁴⁰⁵ For the Distribution Substation Plan, SCE's forecasts are based on a combination of scoped work, forecasted capital expenditures using a growth ratio,⁴⁰⁶ and unit counts multiplied by historical unit distribution costs.⁴⁰⁷ The Transmission Substation Plan forecast is based on scoped projects.⁴⁰⁸ System Improvement Programs forecasts are based on a combination of historical costs for similar

⁴⁰² Ex. SCE-02, Vol. 4, Pt. 2 at 10-14.

⁴⁰³ *Id.* at 22.

⁴⁰⁴ DER-Driven Grid Reinforcement capital expenditures upgrade the distribution system to enable the integration of DERs. In direct testimony, SCE's 2019-2021 total company forecast for DER-Driven Grid Reinforcement was \$43.035 million. (Ex. SCE-02, Vol. 4, Pt. 2 at 26, Table II-1 and 56.) In rebuttal testimony, SCE agrees with Cal Advocates to remove these forecast costs and instead track grid upgrade costs associated with DER growth in a memorandum account for future cost recovery. (Ex. SCE-13, Vol. 4, Pt. 2 at 10.)

⁴⁰⁵ Reported as Total Company costs. (*Id.* at 4, Table I-2.)

⁴⁰⁶ The growth ratio is used to calculate the proportion of capital expenditures relative to the forecasted load growth in that year, and is calculated using the costs of completed or planned distribution circuit upgrades from a given year and the corresponding load growth assumption. (Ex. SCE-02, Vol. 4, Pt. 2 at 29-30.)

⁴⁰⁷ *Id.* at 29-30, 34-35, 37-38, and 51-52.

⁴⁰⁸ *Id.* at 72-73.

work and historic unit costs as well as estimated growth in Volt-ampere reactive power (VAR) demand.⁴⁰⁹ The Land Rights Management forecast is based on historic operating levels.⁴¹⁰

In response to Cal Advocates' recommendation to track DER-Driven Load Growth in a memorandum account for future reasonableness review,⁴¹¹ SCE agrees it would be appropriate to remove DER-Driven Grid Reinforcement costs from the GRC Load Growth forecast and "to establish, in a non-precedential manner, a memorandum account to track and record capital expenditures associated with the early stages of this specific DER-Driven Grid Reinforcement program."⁴¹² SCE requests the Commission authorize a memorandum account for the 2021-2024 period, with an associated capital expenditure "target" up to the currently requested 2021-2023 forecast of \$93.5 million. SCE also indicates it will propose a 2024 capital expenditure "target" for 2024 in Track 4 of this proceeding.⁴¹³

13.1.1. Intervenor

In its opening brief, Cal Advocates clarifies its initial recommendations concerning DER-Driven Load Growth are unchanged, including: (1) all expenditures recorded through 2023 will be tracked in a memorandum account; (2) all expenditures in the memorandum account will be excluded from the revenue requirement and rates, unless a retrospective review shows the

⁴⁰⁹ VAR is the unit used to measure reactive power in alternating current electric systems. Because alternating current systems have varying voltage, these systems must vary the current with the voltage to maintain stability. (*Id.* at 19, fn. 26; also, *Id.* at 79-80, 85, and 89-90.)

⁴¹⁰ *Id.* at 92.

⁴¹¹ Ex. PAO-05 at 49-65.

⁴¹² Ex. SCE-13, Vol. 4, Pt. 2 at 10.

⁴¹³ *Ibid.*

expenditures to be reasonable; and (3) treatment of 2024 expenditures will be addressed in Track 4 of this proceeding.⁴¹⁴

SBUA recommends the Commission: (1) order SCE to withdraw its application and refile it with updated forecasts and assumptions that better fit the economic upheaval caused by the COVID-19 pandemic, or in the alternative adopt Cal Advocates' proposed \$125 million adjustment to SCE's estimated 2020 capital expenditure budget to account for the economic downturn associated with COVID-19;⁴¹⁵ (2) freeze all but essential utility investment;⁴¹⁶ (3) order SCE to prioritize the deployment of "beneficial, flexible, distributed energy resources (DER) in-lieu of fixed distribution investments within its grid modernization program;"⁴¹⁷ (4) order SCE to reconcile its load forecasts for its local "adjustments" with its overall system forecast to avoid over-forecasting; (5) order SCE to revise and refile its distribution investment plan to align its load growth planning with the Commission-adopted load forecasts for resource planning and to shift more funds to the grid modernization functions that focus on facilitating DER deployment; (6) order an audit of SCE's spending in other categories to determine if the activities are justified and appropriate cost controls are in place; and (7) order SCE to do at least one of the following: "a) present an empirically defensible set of criteria and underlying data beyond load forecasts to enable parties to effectively evaluate distribution system investments with adequate time in this proceeding to fully vet these benchmarks....b) recover investments proportionately to the utilization rate of those additions over time so that SCE

⁴¹⁴ Cal Advocates OB at 104.

⁴¹⁵ Ex. SBUA-01 at 4; SBUA RB at 4.

⁴¹⁶ Ex. SBUA-01 at 5.

⁴¹⁷ *Ibid.*

has an incentive to 'right size' such assets, or c) forego making these investments until a new method can be developed to evaluate their prudence, including a demonstration of urgency that precludes the usual periodic review in rate cases."⁴¹⁸

SBUA argues that in the context of COVID-19, where millions of people have been laid off and where more than 40 percent of small businesses are closed or are expected to close, SCE has prepared an application that no longer reflects "the current world or the most likely path going forward."⁴¹⁹ SBUA also asserts that SCE has consistently over-forecast load growth to justify large infrastructure investments that failed to materialize; that ongoing systematic alterations to Southern California's economy, and a shift from centralized power generation to customer-driven DERs, have contributed to the misalignment between forecasted and actual loads; that SCE's overall peak demand forecast rises rapidly from 2020-2024, while forecasts by the CEC and CAISO are flat; that SCE uses three divergent load forecasts for planning and budgeting purposes in this GRC (*e.g.*, System, B-Bank, and Non-Coincident); and that a comparison of SCE's forecasted and recorded 2019 capital expenditures reveals substantial diversions, including an increase in spending on wildfire-related activities and a decrease in spending on Grid Modernization activities.⁴²⁰

Lastly, SBUA asserts that SCE's proposed revenue increase is unaffordable, and that SCE's utility-centric investment approach is inappropriate in the current environment of economic volatility.⁴²¹

⁴¹⁸ *Ibid.*

⁴¹⁹ *Id.* at 7.

⁴²⁰ *Id.* at 10-24.

⁴²¹ *Id.* at 24-27.

13.1.2. SCE Response to SBUA

In response, SCE states that SBUA's load forecasting recommendations are in direct conflict with the DRP Proceeding (R.14-08-013), the DRP requirement that SCE use the demand forecast from the CEC's IEPR, the CEC stakeholder process used to develop the IEPR demand forecast, and the outcome of the multi-party Demand Forecasting Working Group that vetted SCE's method for disaggregating the IEPR system-wide demand forecast to the individual circuits within SCE's distribution system. SCE further asserts the disaggregated DER and demand growth used to develop its 2021 GRC request was affirmed in the August 1, 2018, Administrative Law Judge's Ruling in R.14-08-013. SCE indicates its load forecast also incorporates incremental load growth (*i.e.*, marijuana cultivation, Light Electric Vehicle (LEV) superchargers, mega tract homes, and agricultural pump loads) that may not have been fully reflected in the CEC's forecast.⁴²²

Contrary to SBUA's position, SCE asserts it does not "systematically over-forecast," but rather recalibrates its distribution system plan on an annual basis according to the latest recorded peak loads. SCE indicates it will cancel projects as load forecasts change,⁴²³ and that the review and cancellation of projects, as well as the identification of any projects that are no longer necessary to mitigate criteria violations or that may be deferred by DERs, are reported in SCE's annual Distribution Deferral Opportunity Report.⁴²⁴

⁴²² SCE OB at 89.

⁴²³ For example, SCE cites to its removal of certain Transmission Substation Plan project forecast expenditures over the course of the proceeding due to changes in the load forecast. (*See* Ex. SCE-13, Vol. 4, Pt. 2 at 19.)

⁴²⁴ *Id.* at 19.

SCE asserts that SBUA conflates load forecasts spanning 15 years to create a false characterization of over-forecasting, and that changes in law, different economic outlooks, and shifts in technology have all dramatically influenced forecasts over the span of time SBUA's testimony covers, and that load forecasting and planning for system reliability should be based on information available at the time of analysis. Further, SCE states that SBUA relies upon load curves developed from metered data which are not comparable to forecasted peak demand and do not account for potential DER performance.⁴²⁵

Lastly, SCE argues the Commission should reject SBUA's argument that SCE should only recover the costs of their distribution assets on a "percent of utilization" basis. SCE asserts it must plan for forecast peak loading to enable the distribution system to serve its customers when the electricity will be needed, including during extreme events, and that basing recovery on a "percent of utilization" can pose significant public safety hazards and lead to higher costs in customized equipment procurement.⁴²⁶

13.1.3. Discussion

It is uncontested in this proceeding that the growth of DERs can cause criteria violations that compromise the safety and reliability of the grid. While Cal Advocates observes that utility-owned equipment is not the only option to mitigate DER integration issues,⁴²⁷ due to the uncertainty in the timing and magnitude of potential DER-driven reliability violations, Cal Advocates and SCE both agree it is reasonable to remove SCE's GRC forecasts for the DER-Driven Grid Reinforcement Program in this GRC and instead track these costs in a

⁴²⁵ *Id.* at 19-22.

⁴²⁶ *Id.* at 23.

⁴²⁷ Ex. PAO-05 at 59-60.

memorandum account for future reasonableness review. We agree it is appropriate to establish a memorandum account to track and record capital expenditures associated with the early stages of SCE's DER-Driven Grid Reinforcement Program, and authorize SCE to establish a memorandum account for this purpose. Given the high degree of uncertainty in the timing and magnitude of DER-driven reliability violations, we do not see a need to establish an associated capital expenditure "target" up to SCE's currently requested 2021-2023 forecast. SCE bears the burden of demonstrating the reasonableness of any costs incurred for the DER-Driven Grid Reinforcement Program. Since Track 4 of this proceeding is not intended to "relitigate determinations made in the Commission's Track 1 decision,"⁴²⁸ and we decline to adopt a capital expenditure "target" for 2021-2023, we do not intend to revisit the issue of setting a capital expenditure "target" in Track 4 of this proceeding and clarify that SCE is authorized to track and record capital expenditures associated with the DER-Driven Grid Reinforcement Program for the 2021-2024 period.

We decline to adopt any of SBUA's specific recommendations. As discussed in Section 5 (Policy), we remain keenly aware that our statutory obligation to approve "just and reasonable" rates is made even more critical in the current economic uncertainty driven by the COVID-19 pandemic. However, directing SCE to refile its entire GRC application would not only be an inefficient use of extensive party, Commission, and ultimately ratepayer resources, but would not necessarily result in a different outcome. It is not clear when or if the cumulative economic impacts of COVID-19 for this GRC cycle will be fully known, but we take faith in the robust evidentiary record and party

⁴²⁸ Amended Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judges, dated April 17, 2020, at 9.

participation throughout this proceeding, which has enabled us to limit rate increases to only those which have been shown to be necessary, and consistent with safe, reliable, and affordable service. Similarly, SBUA's recommendation to "freeze all but essential utility investment" relates to the reasonableness of SCE's proposed revenue requirement. While it is not within the scope of this proceeding to consider modification of prior Commission policy directives,⁴²⁹ we have considered whether activities are discretionary as part of our evaluation of SCE's individual GRC requests.

We also find SBUA's load growth arguments to be without merit. As noted by SCE, SBUA's load forecasting recommendations are in direct conflict with D.18-02-004, the Commission's decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), as well as the Administrative Law Judge's August 1, 2018 ruling in R.14-08-013.⁴³⁰ Further, we agree with SCE that SBUA's comparison of load forecasts spanning 15 years ignores the differences in available information over time and the progression of load forecasting methodologies, including the more recent requirement that SCE use an IEPR demand forecast in developing its GRC Load Growth request.

SBUA also recommends that the Commission "order an audit of SCE's spending on other categories to determine if the activities are justified and the appropriate cost controls are in place." SBUA's recommendation is based on a comparison of SCE's recorded 2019 capital expenditures to its approved 2018

⁴²⁹ See Assigned ALJs' E-mail Ruling Granting in Part, and Denying in Part, Southern California Edison Company's Motion to Strike Portions of Opening Testimony of the Small Business Utility Advocates, dated June 17, 2020, at 3.

⁴³⁰ D.18-02-004 at 17-24; Assigned Administrative Law Judge's Ruling on the Distribution Working Group Progress Report issued in R.14-08-013, dated August 1, 2018, at 7.

GRC forecast, where SBUA concludes that SCE is not moving forward aggressively on implementing Grid Modernization policies to encourage the adoption of DERs.⁴³¹ As we have stated elsewhere in this decision, and in D.96-12-066, ratemaking is not, nor has it ever been, an exact science that guarantees perfect results from all perspectives.⁴³² Beyond the broad observation that there are differences in SCE's forecasted and recorded 2019 capital expenditures, SBUA does not identify any specific instances of utility mismanagement that might warrant a formal audit, nor does SBUA provide any specific criticisms of, or alternative recommendations to, the individual Grid Modernization forecasts SCE presented in this GRC.

Lastly, we reject SBUA's recommendation that SCE should only recover the costs of their distribution assets on a "percent of utilization" basis. As noted by SCE, this proposal fails to account for anticipated peak loading events and would put the safety and reliability of the electric system at risk.

We have reviewed the supporting materials for SCE's Load Growth forecast and find the amounts reasonable and well-supported. Therefore, we approve SCE's 2019-2021 capital expenditure forecast of \$1.029 billion for the Load Growth BPE.

13.2. Transmission Projects

The Transmission Projects BPE includes work SCE completes on its high voltage transmission system (500 kV and 220 kV). While the majority of work for Transmission Projects falls within Federal Energy Regulatory Commission (FERC) jurisdiction, some of these projects include components under CPUC

⁴³¹ Ex. SBUA-01 at 21.

⁴³² See D.96-12-066 at 695.

jurisdiction, including upgrades to the underlying subtransmission system and equipment supporting telecommunications, automation, and controls.

Transmission Projects are categorized as Grid Reliability, Renewable Transmission, or General Interconnection Remedial Action Scheme (RAS). Grid Reliability Projects are developed as part of CAISO's Transmission Planning Process (TPP) and are required to support reliability and compliance with NERC, WECC, CAISO, and SCE system performance standards and criteria. Renewable Transmission Projects include specific renewable generation interconnection projects and policy-driven projects identified by CAISO through the TPP as those enabling the grid to support state and federal directives (including California's Renewables Portfolio Standard Program). SCE does not provide further description of the Generation Interconnection RAS as there are no CPUC-jurisdictional capital expenditures forecast for these projects from 2019-2023.⁴³³

SCE's 2019-2021 capital expenditure forecast of \$1.444 billion⁴³⁴ for Transmission Projects based on scoped work, the timing and execution of activities, applicable allocations, and adjustments and/or allowances.⁴³⁵ Of that amount, approximately 12 percent is attributed to CPUC-jurisdictional costs.⁴³⁶

⁴³³ Ex. SCE-02, Vol. 4, Pt. 2 at 93 and 96-102.

⁴³⁴ Includes FERC- and CPUC-jurisdictional costs. (Ex. SCE-13 Vol. 04, Pt. 2, Table III-4 at 25.) SCE's methodology for allocating capital expenditures between FERC and CPUC jurisdictions is discussed in Section 45.1.

⁴³⁵ Ex. SCE-02, Vol. 4, Pt. 2 at 96.

⁴³⁶ *Id.* at 98, Tables III-24 and III-25. Percentage is approximate, based on 2019 forecast instead of 2019 recorded costs.

We find reasonable and approve SCE's uncontested capital expenditure forecast for Transmission Projects.⁴³⁷

13.3. Engineering O&M

The Engineering BPE includes Transmission and Distribution Grid Engineering costs necessary to ensure SCE's grid is reliable, provides adequate power, and is capable of interconnecting new generation resources to accommodate load growth and the State's renewable generation requirements. SCE's transmission system, which is under operational control of the CAISO, is routinely evaluated against NERC Reliability Standards, WECC Reliability Standards/Criteria, and the CAISO Planning Criteria. In addition to these activities, the Engineering BPE also includes investigative and engineering work to address customer-reported concerns with power quality (referred to as Load Side Support).

SCE's TY O&M forecast for the Engineering BPE is \$12.757 million.⁴³⁸ SCE's forecast is comprised of: (1) \$11.480 million for the Grid Engineering GRC Activity, which is based off 2018 recorded costs plus an increase of \$0.280 million in labor⁴³⁹ and an increase of \$0.198 million in non-labor;⁴⁴⁰ and (2) \$1.277 million

⁴³⁷ Our approval is limited to CPUC-jurisdictional capital expenditures, and does not speak to the reasonableness of transmission-related capital expenditures that fall within FERC jurisdiction.

⁴³⁸ Ex. SCE-13, Vol. 4, Pt. 2, Table I-1 at 3.

⁴³⁹ The incremental labor cost covers additional annual planning assessments, long-term assessments supporting state initiatives, other non-capitalized work (including property reviews and support for regulatory activities), and increased resources devoted to root cause investigations (including for wildfire event equipment investigations). (Ex. SCE-02, Vol. 4, Pt. 2 at 109-110.)

⁴⁴⁰ The incremental non-labor cost covers additional engineering assessment and studies on wildfire-related activities, transmission-level projects, and protection and distribution apparatus projects. (*Ibid.*)

for Load Side Support, which is based on a three-year average of labor costs (2016-2018)⁴⁴¹ and 2018 recorded non-labor costs plus an increase of \$0.218 million to account for specialized investigation work performed by a third-party firm and contract employees for specialized engineering.⁴⁴²

Cal Advocates reviewed and does not oppose SCE's \$11.480 million request for the Grid Engineering GRC Activity. However, Cal Advocates recommends a \$0.205 million reduction to SCE's non-labor forecast for Load Side Support. Cal Advocates' forecast utilizes 2016-2018 recorded non-labor costs instead of 2018 recorded, based on arguments that SCE's non-labor expenses vary from year to year.⁴⁴³

In response, SCE asserts that Cal Advocates does not take into consideration the increase in non-labor work expected for 2021. SCE provides two reasons why non-labor expenses are expected to increase compared to prior recorded years: the first is that SCE transitioned Radio & TV Interference Inspectors from SCE employees to contractors, which will result in higher non-labor expenses. Second, SCE's forecast includes incremental external support to address the increasing complexity of interference and power quality issues.⁴⁴⁴

We find SCE provides sufficient justification for its non-labor forecast. SCE's recorded 2018 non-labor expenses for Load Side Support (\$0.159 million) are lower than its recorded expenses for both 2016 (\$0.186 million) and 2017

⁴⁴¹ Includes a corrected 2018 recorded amount to reflect an accounting discrepancy. (*Id.* at 113-114.)

⁴⁴² *Id.* at 115.

⁴⁴³ Ex. PAO-07 at 14.

⁴⁴⁴ Ex. SCE-13, Vol. 4, Pt. 2 at 29-30.

(\$0.170 million).⁴⁴⁵ While Cal Advocates' recommendation would smooth out fluctuations between these years (and result in a slight increase compared to 2018 recorded), it ignores the specific incremental work that SCE expects to perform in 2021. We have reviewed SCE's underlying rationale and cost details for these incremental costs and generally find SCE's non-labor forecast to be reasonable. We have also reviewed and find reasonable SCE's uncontested forecast for the Grid Engineering GRC Activity, and SCE's uncontested labor expense forecast for Load Side Support. Therefore, we approve SCE's full TY O&M request of \$12.757 million for the Engineering BPE.

14. New Service Connections and Customer Requested System Modifications

SCE's funding requests for the New Service Connections and Customer Requested System Modifications BPEs allow SCE to respond to requests from customers. SCE's requests include funding for: (a) connecting new residential, commercial, and agricultural customers to SCE's system; (b) meeting customer requests under Tariff Rule 20 to underground certain overhead facilities; (c) relocating existing SCE facilities to meet customer needs; and (d) providing customers with added facilities under Tariff Rule 2.⁴⁴⁶

14.1. New Service Connections

SCE's new service connection programs are driven by SCE's obligation to serve customers⁴⁴⁷ and meet customer growth requirements. Customer growth results in new service connection work including the installation of a new meter in a new home or business, upgrading a meter due to increased load, extending

⁴⁴⁵ Ex. SCE-02, Vol. 4, Pt. 2, at 113, Figure IV-29.

⁴⁴⁶ Ex. SCE-02 Vol. 4, Pt. 3 at 1.

⁴⁴⁷ *Id.* at 3; See also Line Extension Tariff Rule 15, Service Extension Rule 16, and LS-1, LS-2, LS-3, OL-1, AL-2, DSL, and TC-1 Street and Area Lighting/Traffic Control Rates.

electrical facilities to new communities where new meters must be set, or installing streetlighting to serve the new or expanded communities where new meters must be set.

SCE forecasts 2019-2021 capital expenditures of \$760.537 million for new service connections.⁴⁴⁸ SCE's forecast capital expenditures are separated by customer class as follows (nominal, \$000):⁴⁴⁹

Customer Class	2019	2020	2021
Residential	110,480	137,670	149,787
Commercial	94,111	97,968	88,533
Agricultural	3,409	7,233	7,465
Streetlights	14,692	23,726	25,464
Total	222,692	266,596	271,249

SCE uses the gross meter sets from its retail sales forecast as the basis for developing its capital expenditure forecasts for each new service connection work activity.⁴⁵⁰

TURN recommends reductions to SCE's residential and commercial new connections forecasts. SCE's forecasts for the agricultural and streetlights customer classes are unopposed. However, SCE's forecast for the streetlights customer class is dependent on the residential gross meter sets forecast, which is contested by TURN.

⁴⁴⁸ Ex. SCE-13, Vol. 4, Pt. 3 at 3, Table I-2. SCE updated its 2019 forecast to include 2019 recorded expenditures.

⁴⁴⁹ *Id.* at 4, Table II-3.

⁴⁵⁰ Ex. SCE-02, Vol. 4, Pt. 3 at 4.

14.1.1. Residential New Connections

14.1.1.1. SCE's Forecasts

Extending service to new residential customers may entail the construction of new service connections, distribution line extensions, tract development, and/or backbone development. SCE's 2019 recorded and 2020 forecast capital expenditures for these activities are \$110.480 million and \$137.670 million, respectively.⁴⁵¹ SCE's 2021-2023 capital expenditure forecasts for these activities are as follows (nominal, \$000):⁴⁵²

Activity	2021	2022	2023
Residential Service Connections	27,801	30,255	32,828
Residential Line Extensions	20,521	21,394	22,297
Residential Tract Line Extensions	70,571	76,975	77,235
Residential Backbone Development	30,893	34,113	34,052
Total	149,787	162,737	166,412

SCE calculates the forecast capital expenditures for the residential service connections activity by multiplying the forecast residential meter set unit cost by the number of residential gross meter sets SCE forecasts to install from 2019-2023.⁴⁵³

SCE's calculation of residential new meters is derived from a regression analysis that calculates correlation coefficients between lagged housing starts and monthly residential meter installations from January 2008-August 2018.⁴⁵⁴ SCE then applies the calculated coefficients to a forecast of new housing starts to

⁴⁵¹ Ex. SCE-13, Vol. 4, Pt. 3 at 4, Table II-3.

⁴⁵² *Id.* at 6, Table II-5.

⁴⁵³ Ex. SCE-02, Vol. 4, Pt. 3 at 12.

⁴⁵⁴ Ex. TURN-02 at 45.

derive an estimate of new meter connections.⁴⁵⁵ SCE's housing start forecast is primarily based on a forecast provided by Moody's Analytics. SCE states it selected a vendor that held a less optimistic view on housing starts compared to the other vendors it considered, selected a more conservative scenario among the alternatives offered by Moody's, and made an additional modeling adjustment to reduce the selected housing start forecast.⁴⁵⁶

SCE's forecasts for installation of residential line extensions, tract development, and backbone development correlate with the forecast number of meter sets.⁴⁵⁷ To calculate the capital expenditure forecast for each of these activities, SCE multiplies the forecast unit cost by forecast amount of installations.⁴⁵⁸

14.1.1.2. TURN's Forecasts

TURN accepts SCE's calculated coefficients from its regression model for the residential meter forecast but recommends applying a lower number of forecast housing starts to the SCE forecast.⁴⁵⁹ Because the capital expenditure forecasts for the various residential new connection activities are dependent on the meter forecast, TURN's recommended reduction to the meter forecast results in reductions to the capital expenditure forecasts for all the activities. TURN does not oppose SCE's methodology for translating the gross meter set forecast

⁴⁵⁵ *Ibid.*

⁴⁵⁶ Ex. SCE-18, Vol. 1 at 34.

⁴⁵⁷ Ex. SCE-02, Vol. 4, Pt. 3 at 14-15, 19, 23.

⁴⁵⁸ *Id.* at 15, 20, 23.

⁴⁵⁹ Ex. TURN-02 at 55.

to the forecasts of new connection work activities or SCE's unit cost forecasts for the various activities.⁴⁶⁰

TURN argues that SCE has consistently over-estimated the number of new residential meter connections and corresponding new service connection capital expenses, primarily due to overly optimistic housing start forecasts provided by Moody's Analytics. TURN notes that SCE's forecasts from 2012-2018 over-forecast new meter connections by around 178,000 meters and corresponding expenditures by \$860 million.⁴⁶¹ The Commission has at times adopted lower meter and/or expenditure forecasts than those forecasted by SCE. However, TURN notes that SCE's expenditures were still \$265 million less than authorized amounts during this period.⁴⁶²

TURN argues that housing starts and new meter connections are beginning to level off, and therefore, recommends an average of actual housing starts from 2015-2019 as a more reasonable estimate.⁴⁶³ TURN argues that the number of meters may decrease even further than expected in 2021 due to the effects of the COVID-19 pandemic, which are not accounted for in SCE's and TURN's forecasts.⁴⁶⁴ TURN's proposed methodology results in the following residential meter forecasts in comparison to SCE:⁴⁶⁵

⁴⁶⁰ TURN OB at 48; Ex. TURN-02 at 57.

⁴⁶¹ Ex. TURN-02 at 45-46.

⁴⁶² *Id.* at 46.

⁴⁶³ Ex. TURN-02-C at 55-56.

⁴⁶⁴ Ex. TURN-02 at 50.

⁴⁶⁵ *Id.* at 47, Table 12.

	Residential Meters		
Year	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)

TURN's recommended reduction to the number of forecast residential meters results in the following capital expenditure forecasts (nominal, \$000):⁴⁶⁶

Activity	2021	2022	2023
Residential Service Connections	23,314	23,632	25,433
Residential Line Extensions	19,763	20,275	21,047
Residential Tract Line Extensions	53,601	58,024	77,235
Residential Backbone Development	21,842	24,006	34,052
Total	118,520	125,937	157,768

14.1.1.3. Discussion

We find that SCE has failed to adequately justify its forecast for residential meter installations. It is undisputed that SCE has consistently over-forecast new residential meters since the 2012 GRC.⁴⁶⁷ SCE contends that it has revised its forecast methodology and that the 2021 GRC forecast relies on different and more conservative scenarios compared to previous GRCs.⁴⁶⁸ Although SCE made some adjustments, we do not have confidence that SCE's revised methodology adequately addresses the consistent upward bias demonstrated by TURN. SCE still primarily relies on Moody's forecast of housing starts for its forecast. TURN notes that SCE's adjustments in this GRC reduced Moody's forecast by 8.6 percent in 2021, 10.2 percent in 2022, and 4.1 percent in 2023,

⁴⁶⁶ Ex. SCE-13, Vol. 4, Pt. 3 at 6, Table II-5. SCE converted a table taken from TURN's testimony from 2018 Constant to Nominal dollars. (*Id.* at 6, fn. 6.)

⁴⁶⁷ TURN OB at 50-51; SCE OB at 94.

⁴⁶⁸ Ex. SCE-18, Vol. 1

whereas SCE's 2018 GRC forecast using Moody's forecast was 20 percent too high for 2018 and 25 percent too high for 2019.⁴⁶⁹

The 2019 recorded expenditures further support the conclusion that SCE's proposed methodology will likely result in over-forecasting. In this GRC, SCE initially forecast 2019 expenditures of \$128.246 million.⁴⁷⁰ In rebuttal testimony, SCE reported 2019 recorded expenditures of \$110.480 million.⁴⁷¹ SCE states that the underspend was primarily due to fewer residential meter installations than were forecast.⁴⁷²

We find that TURN provides a more reasonable forecast. SCE argues that TURN's proposed methodology is arbitrary, hindsight based, and would have resulted in significant under-estimation of new housing starts in a majority of the past eight years.⁴⁷³ The question of whether it is appropriate to use a historical average to forecast costs is highly fact specific. TURN's proposed methodology may not be appropriate in all years, such as when past circumstances are unlikely to repeat during the forecast period. For example, TURN explains that it did not propose use of a five-year average in prior GRCs due to the impacts of the 2007 Great Recession, which is generally thought to have lasted into 2013.⁴⁷⁴ TURN presents data that there has been a leveling off of housing starts after the recovery from the Great Recession.⁴⁷⁵ Based on the data presented by TURN, we

⁴⁶⁹ TURN OB at 52; Ex. TURN-24, Data Request TURN-SCE-102, Response to Question 2.

⁴⁷⁰ Ex. SCE-02, Vol. 4, Pt. 3 at 6, Table II-3.

⁴⁷¹ Ex. SCE-13, Vol. 4, Pt. 3 at 4, Table II-3.

⁴⁷² *Id.* at 3, fn. 3.

⁴⁷³ SCE OB at 95.

⁴⁷⁴ TURN OB at 60-61.

⁴⁷⁵ *Id.* at 55-56.

find use of a five-year (2015-2019) average of housing starts to develop the residential gross meter set forecast for this GRC period to be reasonable. We also find a more conservative forecast to be reasonable given the economic uncertainties during this rate case period due to the impacts of the COVID-19 pandemic, which are still unknown, and therefore, not accounted for in the parties' forecasts.

SCE argues that the Commission should not "discard the well-established methodology of forecasting new meter connections on a forward-looking basis based on expert input on housing and other macroeconomic trends."⁴⁷⁶

However, in SCE's 2018 GRC, the Commission adopted TURN's proposal to base the new meter forecast on average 2014-2016 historical growth due to the same concerns regarding consistent over-forecasting by SCE.⁴⁷⁷ The 2018 and 2019 recorded data demonstrate that TURN's forecasts from the 2018 GRC were more accurate than SCE's forecasts.⁴⁷⁸

Therefore, we adopt TURN's residential meter forecast and corresponding residential new connection capital expenditure forecasts for 2021-2023. TURN did not dispute SCE's 2020 forecast capital expenditures but as discussed above, we do not find SCE's forecast methodology to be reasonable. We instead adopt a 2020 residential meter forecast of 29,248 and corresponding capital expenditures of \$115.086 million based on recorded lagged housing starts.⁴⁷⁹ We also adopt SCE's recorded 2019 costs, which are unopposed.

⁴⁷⁶ SCE OB at 95.

⁴⁷⁷ D.19-05-020 at 274, 277.

⁴⁷⁸ TURN OB at 54, Table 12-7.

⁴⁷⁹ The confidential recorded lagged housing starts used by TURN to arrive at their proposed five-year (2015-2019) average of housing starts was inputted into TURN's replica of SCE's

14.1.2. Commercial New Connections

Extending service to new commercial customers may entail the construction of new service connections, distribution line extensions, and tract development. SCE's capital expenditure forecasts for these activities are dependent on the number of commercial gross meter sets SCE forecasts to install. SCE calculates the forecast capital expenditures for commercial service connections by multiplying the forecast commercial meter set unit cost by the forecast number of gross meter sets.⁴⁸⁰ To calculate the capital expenditure forecast for commercial line extensions and tract development, SCE multiplies the forecast unit cost for each activity by the forecast amount of installations for each activity, which is based on the forecast number of gross meter sets.⁴⁸¹

The regression model SCE uses to generate its commercial meter sets forecast relies on the strong correlation between commercial meter and residential meter growth observed over time. TURN contends that SCE's meter regression model is not likely to provide a reasonable basis to predict the number of commercial meters to be installed over the forecast rate case period.⁴⁸² TURN found that 94 percent of variation in the data could not be explained with SCE's regression.⁴⁸³ SCE acknowledges that residential meter sets no longer appear to have robust explanatory power in forecasting commercial/industrial sets and accepts TURN's proposal for a reduced commercial meter set forecast.⁴⁸⁴ SCE

regression model to determine the corresponding 2020 forecast of meter installations and capital expenditures.

⁴⁸⁰ Ex. SCE-02, Vol. 4, Pt. 3 at 27.

⁴⁸¹ *Id.* at 30 and 34.

⁴⁸² Ex. TURN-02 at 58-59.

⁴⁸³ *Ibid.*

⁴⁸⁴ Ex. SCE-18, Vol. 1 at 39.

also agrees to investigate alternative fundamental drivers to better forecast commercial/industrial meter sets in the future.⁴⁸⁵

TURN forecasts 4,751 commercial sets annually for 2021-2023 based on the average number of commercial meters installed over the last five recorded years (2015-2019).⁴⁸⁶ We find reasonable and adopt TURN's unopposed commercial meter forecast. SCE's methodology for translating the commercial gross meter set forecast to the forecast of commercial new connection work activities and SCE's unit cost forecasts for the various activities are unopposed. The adoption of TURN's commercial meter forecast results in the following adopted capital expenditures for 2021-2023 (nominal, \$000):⁴⁸⁷

Activity	2021	2022	2023
Commercial Service Connections	25,142	25,870	26,614
Commercial Line Extensions	42,127	43,346	44,593
Commercial Tract Line Extensions	21,263	21,878	22,508
Total	88,533	91,094	93,714

We also adopt SCE's unopposed request for approval of its 2019 recorded capital expenditures of \$94.111 million.⁴⁸⁸ SCE's 2020 forecast costs are also based on SCE's meter regression model. Consistent with the adopted forecast for 2021-2023, we instead adopt a meter forecast of 4,751 for 2020, which results in corresponding capital expenditures of \$85.804 million (\$nominal).

⁴⁸⁵ *Ibid.*

⁴⁸⁶ Ex. TURN-02 at 59.

⁴⁸⁷ Ex. SCE-13, Vol. 4, Pt. 3 at 8, Table II-7. SCE converted a table taken from TURN's testimony from 2018 Constant to Nominal dollars. (*Id.* at 8, fn. 8.)

⁴⁸⁸ *Id.* at 4, Table II-3.

14.1.3. Agricultural New Connections

Extending service to new agricultural customers may entail the construction of new service connections or distribution line extensions. SCE's capital expenditure forecasts for these activities are dependent on the number of agricultural gross meter sets SCE forecasts to install. SCE calculates the forecast capital expenditures for agricultural service connections by multiplying the forecast agricultural meter set unit cost by the forecast number of gross meter sets.⁴⁸⁹ To calculate the capital expenditure forecast for agricultural line extensions, SCE multiplies the forecast unit cost for the activity by the forecast amount of installations, which is based on the forecast number of gross meter sets.⁴⁹⁰

SCE's 2019-2021 forecast capital expenditures for agricultural new connections are unopposed. We find reasonable and approve SCE's 2019 recorded costs. However, we find that SCE has failed to adequately justify its 2020 and 2021 forecasts.

SCE's recorded expenditures from 2016-2019 have shown a consistent downward trend as follows (nominal, \$000):⁴⁹¹

Activity	2016	2017	2018	2019
Agricultural New Service Connections	9,207	5,330	3,831	3,409

Despite this downward trend, SCE projects an increase in agricultural meter connections in 2020 and 2021. SCE does not provide any explanation as to how it developed its agricultural gross meter sets forecast or why the forecast

⁴⁸⁹ Ex. SCE-02, Vol. 4, Pt. 3 at 38.

⁴⁹⁰ *Id.* at 39.

⁴⁹¹ *Id.* at 6, Table II-3; Ex. SCE-13, Vol. 4, Pt. 3 at 4, Table II-3.

and corresponding capital expenditure forecast would trend upward. Based on the information in the record, it seems likely that SCE's forecast is overly optimistic. For example, SCE's forecast methodology yielded a 2019 forecast of \$6.817 million but SCE's 2019 recorded costs were \$3.409 million.⁴⁹²

In the absence of an adequately justified forecast, we find it reasonable to adopt capital expenditures for 2020 and 2021 based on recorded costs. Given that there has been a downward trend for three or more years, we approve capital expenditures of \$3.409 million (\$2019) annually for 2020 and 2021 based on SCE's last year recorded costs.

14.1.4. Streetlight System New Connections

The Streetlights new service connections work activity includes installing both service to new streetlights as well as the streetlight itself. Streetlight systems are typically installed in conjunction with residential development.⁴⁹³

SCE's forecast methodology uses the historical ratio of electroliers⁴⁹⁴ to total residential gross meter sets. SCE applies this ratio to the forecast of residential gross meter sets to forecast the total number of electroliers. SCE then multiplies the forecast electrolier unit cost by the forecast number of electroliers to develop its capital expenditure forecast for this category.⁴⁹⁵

SCE's 2019-2021 forecast capital expenditures for Streetlights new service connections are unopposed. We find reasonable and approve SCE's 2019 recorded costs. We also approve SCE's uncontested methodology and forecast

⁴⁹² Ex. SCE-02, Vol. 4, Pt. 3 at 6, Table II-3; Ex. SCE-13, Vol. 4, Pt. 3 at 4, Table II-3.

⁴⁹³ Ex. SCE-02, Vol. 4, Pt. 3 at 42.

⁴⁹⁴ An electrolier is the composite, steel, or concrete pole use to support the streetlight lamp-head and mast-arm. (*Ibid.*)

⁴⁹⁵ *Id.* at 42-43.

electrolier unit costs for calculating the 2020 and 2021 forecasts. However, the 2020 and 2021 Streetlights forecasts are dependent on the forecast for residential gross meter sets. Therefore, these forecasts should be updated based on the adopted residential gross meter sets forecast discussed above.

14.2. Customer Requested Modifications

Customers may request that SCE modify existing electrical facilities based on customer needs and may be responsible for the costs.⁴⁹⁶ These customer requested system modifications include: (1) relocation of distribution and transmission facilities; (2) conversion of overhead distribution and/or transmission lines into underground lines for aesthetics; (3) addition of distribution, substation, and/or transmission facilities; and (4) interconnection of gen-tie lines, storage with wholesale distribution access tariff (WDAT), or transmission owner tariff (TOT).⁴⁹⁷

SCE's 2019 recorded and 2020-2021 forecast capital expenditures for customer requested system modification activities are as follows (nominal, \$000):⁴⁹⁸

⁴⁹⁶ SCE includes customer payments as customer advances under working capital adjustments.

⁴⁹⁷ SCE's Line Extension Tariff Rule 15 and Service Extension Rule 16 regulate all four types of work. OL-1, DWL LS-2, and LS-3 streetlight schedules regulate streetlight modifications. Tariff Rule 20 regulates overhead to underground conversions. Tariff Rule 2H regulates facility additions. WDAT and TOT regulate generation interconnections.

⁴⁹⁸ Ex. SCE-13, Vol. 4, Pt. 3 at 10, 11, 13, 16.

Activity	2019	2020	2021
Distribution Relocations	47,747	52,252	53,898
Transmission Relocations	9,012	12,211	12,465
Rule 20A Conversions	12,332	17,384	9,267
Rule 20 B/C Conversions	30,788	37,163	38,263
Distribution Added Facilities	7,217	12,849	13,258
Transmission/Substation Added Facilities	16,680	64,445	48,175
WDAT/TOT/Gen-Tie	13,666	40,928	28,751
Total	137,442	237,241	271,249

14.2.1. Distribution and Transmission Relocations

SCE performs relocations on its transmission, telecommunication, and distribution facilities upon customers' requests. SCE's forecasts for distribution and transmission relocations are both based on a five-year (2015-2019) average of recorded costs.⁴⁹⁹ SCE's initial forecasts were based on a five-year (2014-2018) average of recorded costs but were modified to incorporate Cal Advocates' recommendation to incorporate 2019 recorded data. We find reasonable and approve SCE's unopposed 2019 recorded costs and updated 2020-2021 forecast capital expenditures for these activities.

14.2.2. Rule 20A Conversions

Under Tariff Rule 20A, each governmental agency in SCE's service territory is allocated a portion of SCE's Rule 20A capital budget to convert overhead power lines to underground lines based on a system-wide formula. SCE's initial capital expenditure forecast for Rule 20A Conversions was based on a five-year (2014-2018) average. SCE also initially proposed to carry over the December 31, 2020 balance in the one-way Rule 20A Balancing Account (forecast

⁴⁹⁹ SCE OB at 97.

as \$31.116 million) to fund Rule 20A projects during this GRC cycle in the event that SCE spends above the 2021 GRC authorized amounts.⁵⁰⁰

SCE subsequently modified its forecast and proposed treatment of the balance in the balancing account based on acceptance of TURN's recommendation to reduce the forecast by \$7.779 million (\$2018) per year between 2021 and 2024 to account for the \$31.116 million balance in the Rule 20A Balancing Account.⁵⁰¹ TURN does not oppose SCE's methodology of using a five-year average to develop the forecast.

Cal Advocates proposes that SCE adjust its Rule 20A Conversion request downward for years 2020 and 2021 by 35 percent in order to address the historical underspend seen with Rule 20A conversions. Cal Advocates' recommendation results in forecasts of \$11.205 million for 2020 and \$11.553 million for 2021.⁵⁰² Cal Advocates also does not object to SCE's initial proposal to carry over its estimated \$31.116 million balance to fund Rule 20A projects during this GRC cycle.

We adopt SCE's unopposed 2019 recorded expenditures. With respect to addressing the historical underspend, we find reasonable TURN's recommended approach, accepted by SCE, of applying the Rule 20A Balancing Account balance to SCE's forecasts for 2021-2024. We agree with TURN and SCE that this approach better aligns with the one-way balancing account mechanism. However, we find that the balance forecast by SCE should be updated to reflect 2019 recorded amounts.

⁵⁰⁰ Ex. SCE-02, Vol. 4, Pt. 3 at 53.

⁵⁰¹ SCE OB at 98; TURN OB at 65.

⁵⁰² Cal Advocates OB at 107.

SCE forecasts the December 31, 2020 balance in the Rule 20A Balancing Account based on 2019 forecast amounts. SCE forecasts a 2019 balance of \$7.509 million based on the difference between the 2019 authorized and forecast amounts.⁵⁰³ The recorded 2019 amounts are now known and part of the record.⁵⁰⁴ The difference between the 2019 authorized and recorded amounts is \$11.900 million rather than the \$7.509 million difference initially forecast by SCE.⁵⁰⁵ The updated balance in the Rule 20A Balancing Account taking into account the 2019 recorded amounts is \$35.507 million, which would reduce SCE's 2021-2024 forecasts by approximately \$8.877 million (\$2018) per year.⁵⁰⁶

Therefore, we approve SCE's forecasts for 2020 and 2021 based on the five-year (2014-2018) average and direct SCE to reduce the forecast by \$8.877 million (\$2018) per year between 2021 and 2024 to account for the \$35.507 million balance in the Rule 20A Balancing Account. We also approve SCE's unopposed request to continue the one-way Rule 20A Balancing Account, which the Commission will review in SCE's next GRC proceeding.

14.2.3. Rule 20B/C Conversions

Rule 20B and Rule 20C conversions include the expenditures necessary to convert overhead lines to underground when customers make a request. Since

⁵⁰³ Ex. SCE-02, Vol. 4, Pt. 3 at 53, Table III-33.

⁵⁰⁴ Ex. SCE-13, Vol. 4, Pt. 3 at 13, Table III-10.

⁵⁰⁵ Ex. SCE-02, Vol. 4, Pt. 3 at 53, Table III-33; Ex. SCE-13, Vol. 4, Pt. 3 at 13, Table III-10. SCE's authorized 2019 amount is \$24.232 million and SCE recorded \$12.332 million for a difference of \$11.900 million. SCE initially forecast 2019 expenditures of \$16.723 million.

⁵⁰⁶ The Commission uses the same methodology used by SCE and TURN to determine the balance and amount of the balance to be applied to each year. SCE adds together the difference between recorded/forecast amounts and authorized amounts for 2018-2020 in nominal dollars to determine the Rule 20A Balancing Account balance. (Ex. SCE-02, Vol. 4, Pt. 3 at 53, Table III-33.) TURN divides this balance by four to determine the reduction per year for 2021-2024, which TURN represents in 2018 constant dollars. (Ex. TURN-06 at 31.)

these conversions are driven by customer requests, forecasts can fluctuate from year to year. Given this unpredictability, SCE uses a five-year average of recorded costs to derive its forecasts. SCE initially proposed use of a 2014-2018 average but updated its forecasts to use a 2015-2019 average based on Cal Advocates' recommendation to incorporate 2019 recorded data. SCE's 2019 recorded costs and 2020-2021 forecasts for Rule 20 B/C conversion sub-activities are as follows (nominal, \$000):⁵⁰⁷

Sub-Activity	2019	2020	2021
Distribution Rule 20B Conversions	12,763	16,919	17,457
Distribution Rule 20C Conversions	9,971	12,407	12,801
Transmission Rule 20B Conversions	5,848	6,147	6,279
Transmission Rule 20C Conversions	2,206	1,690	1,726
Total	30,788	37,163	38,263

Although SCE and Cal Advocates agree on the use of a five-year (2015-2019) average as the basis for the forecasts, Cal Advocates' proposed 2020 and 2021 forecasts differ slightly because Cal Advocates allocates the total 2019 recorded amount of \$30.788 million differently among the four sub-activities. Cal Advocates' allocation is based on SCE's forecast for 2019 expenditures rather than actual recorded amounts.⁵⁰⁸ The differences between Cal Advocates' and SCE's forecasts are slight with SCE's total forecast being \$8,000 less for 2020 and \$2,000 more for 2021.⁵⁰⁹ We find reasonable and adopt SCE's updated 2020 and 2021 forecasts, which are based on its actual recorded expenditures for each

⁵⁰⁷ Ex. SCE-13, Vol. 4, Pt. 3 at 16, Table III-11.

⁵⁰⁸ Cal Advocates OB at 108.

⁵⁰⁹ Ex. SCE-13, Vol. 4, Pt. 3 at 17, Table III-12.

sub-activity. We also find reasonable and adopt SCE's unopposed 2019 expenditures.

14.2.4. Distribution Added Facilities

Facilities requested by a customer which are in addition to or in substitution for standard facilities are called "Added Facilities." Because Distribution Added Facilities costs are variable and driven by customer requests, SCE uses a five-year average to forecast these costs. SCE initially proposed using a 2014-2018 average but updated its forecasts to use a 2015-2019 average based on Cal Advocates' recommendation to incorporate 2019 recorded data.

SCE's and Cal Advocates' 2020 and 2021 forecasts slightly differ because Cal Advocates used a truncated constant-to-nominal conversion rate while SCE used a full conversion rate. Using the full conversion rate as opposed to the truncated rate results in a \$2,000 decrease in 2020 and a \$2,000 increase in 2021.⁵¹⁰ We find reasonable and approve SCE's updated 2020 and 2021 forecasts based on the full conversion rate. We also find reasonable and adopt SCE's unopposed 2019 expenditures.

14.2.5. Uncontested Forecasts

SCE's 2019 recorded costs and 2020-2021 forecasts for Transmission/Substation Added Facilities and WDAT/TOT/Gen-Tie are unopposed.

SCE provides Transmission/Substation Added Facilities materials and equipment for additional reliability enhancements, additional load from a commercial customer, or requests for service at higher voltage levels than SCE's distribution system (interconnection at 66kV or higher).

⁵¹⁰ *Id.* at 20; Cal Advocates OB at 109.

WDAT/TOT/Gen-Tie program projects are driven by requests from generation developers who provide the funds for SCE to design and construct the interconnection facilities, distribution upgrades, or network upgrades necessary to safely and reliably interconnect their projects to SCE's electrical system.

SCE forecasts capital expenditures for these activities based on contracts that are executed by SCE and the customer.⁵¹¹ We find reasonable and approve SCE's uncontested 2019 recorded and 2020-2021 forecast costs for Transmission/Substation Added Facilities and WDAT/TOT/Gen-Tie.

15. Poles

The Poles BPE addresses the inspection, repair, and replacement of poles, and the joint use management of poles. The two major pole replacement programs, the Pole Loading Program and the Deteriorated Pole Program, focus on compliance with GO 95 and GO 165 requirements. Through the Pole Loading Program, SCE assesses poles to identify and repair or replace poles that do not meet GO 95 requirements. Pole replacements identified through other sources, such as the Intrusive Pole Inspection Program or non-programmatic activities, are replaced through the Deteriorated Pole Program.

15.1. Poles O&M

SCE forecasts TY Pole O&M expenses of \$3.798 million. SCE's Pole O&M expenses include costs for: (1) Pole Loading Program assessments and repairs; (2) inspections through the Intrusive Pole Inspection program; (3) the Joint Pole Organization, which manages SCE's relationships with entities that are joint owners of poles and renters that license space for their attachments on SCE's

⁵¹¹ Ex. SCE-02, Vol. 4, Pt. 3 at 64, 66.

poles; and (4) the Third Party Attachments Group, which is responsible for the technical evaluation of third party Requests for Access applications submitted by renters and Joint Pole Authorizations submitted by joint owners. SCE's O&M forecast also includes credits for amounts SCE receives from joint owners as reimbursement for SCE's pole-related O&M activities, including intrusive inspections or minor maintenance activities. SCE's O&M forecast is broken down by activity as follows:⁵¹²

Activity	TY Forecast (\$000)
Pole Loading Program Assessments	1,122
Intrusive Pole Inspection	5,972
Pole Loading Program Repairs	1,132
Joint Pole Credits	(9,793)
Joint Pole Operations	1,997
Request for Attachment Inspections	3,368
Total	3,798

Cal Advocates reviewed SCE's forecast for each of the Pole activities and does not oppose SCE's request.⁵¹³ SCE's total TY O&M forecast represents a sizeable reduction from 2018 recorded costs (\$26.330 million) primarily because SCE expects to finish its assessments under the Pole Loading Program in 2021, and therefore, forecasts a lower assessment count for that year.⁵¹⁴ We find SCE's unopposed TY O&M forecast to be adequately justified⁵¹⁵ and approve SCE's forecast.

⁵¹² Ex. SCE-13, Vol. 5 at 4, Table I-4.

⁵¹³ Cal Advocates OB at 120-121.

⁵¹⁴ Ex. SCE-02, Vol. 5 at 14; Ex. SCE-13, Vol. 5 at 4, Table I-4.

⁵¹⁵ See SCE-02, Vol. 5 at 11-18, 39-41, 44, 50-51, 53-54; Ex. SCE-02, Vol. 5E at 13, 50.

15.2. Poles Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast Pole capital expenditures (nominal, \$000):⁵¹⁶

Capital Expenditures	2019	2020	2021
Distribution Pole Replacements	354,292	388,669	469,551
Transmission Pole Replacements	132,008	98,783	140,022
Steel Stub Installations	383	596	733
Wood Pole Disposal	4,669	3,994	4,676
Joint Pole Capital Credits	(101,525)	(102,802)	(122,391)
Total	389,827	389,240	492,591

SCE's forecasts for Steel Stub Installations and Wood Pole Disposal are unopposed. SCE identifies poles requiring the installation of steel stubs through the Intrusive Pole Inspection Program. Steel stubbing, where applicable, provides a lower-cost alternative to pole replacement (less than 10 percent of the cost for a full pole replacement) and can extend the life of a pole by more than 15 years. Wood Pole Disposal includes costs to dispose of wood poles that are removed from service. Wood poles are treated with chemical preservatives to prevent decay and must be appropriately disposed of to mitigate adverse environmental impacts. We find that SCE has provided adequate justification for these unopposed forecasts⁵¹⁷ and approve them.

Cal Advocates recommends adjustments to the Distribution Pole Replacements, Transmission Pole Replacements, and Joint Pole Credit forecasts. These contested forecasts are discussed below.

⁵¹⁶ Ex. SCE-13, Vol. 5 at 3, Table I-3.

⁵¹⁷ Ex. SCE-02, Vol. 5 at 36-39.

15.2.1. Distribution and Transmission Pole Replacements

SCE's pole replacements include Distribution pole replacements, Transmission pole replacements, Telecommunication pole replacements, and Underbuild work.⁵¹⁸ When a pole supports both Transmission and Distribution equipment, SCE refers to it as a "combo" pole. When a combo pole is replaced, the cost to set the new pole and transfer the Transmission equipment is charged to Transmission and the cost associated with the Distribution equipment is charged to Distribution. This Distribution voltage circuit underneath the transmission circuit is called "Underbuild."

SCE identifies poles requiring replacement through Pole Loading Program assessments, Intrusive Pole Inspections, and planners during the normal course of work.⁵¹⁹ SCE's forecast number of pole replacements includes the poles that SCE has already identified as requiring replacement during the 2019-2021 period and poles that SCE forecasts it will identify and need to replace during the 2019-2021 period. For pole replacements driven by the Pole Loading Program assessments and the Intrusive Pole Inspection program, SCE's forecast is based on the number of assessments or inspections, the expected failure rate, and the timeframe for replacement. Forecast volumes of replacements driven by non-programmatic activities are based on average volumes for 2016-2018.

SCE multiplies the total forecast number of pole replacements for each pole type by the forecast unit cost to calculate its forecast capital expenditures. SCE develops its forecast unit cost for each pole type by first analyzing historical

⁵¹⁸ Forecast Underbuild capital expenditures are included in parties' Distribution Pole Replacement forecasts. Forecast Telecommunication Pole Replacement capital expenditures are included in parties' Transmission Pole Replacement forecasts.

⁵¹⁹ Ex. SCE-02, Vol. 5 at 20-21.

replacement costs from closed work orders.⁵²⁰ SCE then evaluates other factors that would impact the unit cost going forward, including: (1) replacement type and location; (2) additional costs to replace poles in Tier 3 High Fire-Threat Districts due to compressed timeframes for remediation adopted in D.17-12-024; (3) implementation of updated standards to install poles with fire-resistant material wrapped around the base of poles in Tier 2 and Tier 3 areas; (4) increased costs to compensate for decreases in capital-related O&M expense; and (5) decreased costs due to increased reliance on SCE crews for pole replacements rather than contractors.⁵²¹ SCE uses an average of 2021-2023 unit costs for forecasting its 2021 capital expenditures in order to take into account cost changes in the post test years.⁵²²

SCE's capital expenditure forecast also includes the following additional costs that are not included in its forecast unit costs: (1) costs for portable power generators that are occasionally needed where pole replacements are taking place in areas with a single source substation; and (2) costs for replacing 74 poles in 2019 and 23 poles in 2021 on Catalina Island.⁵²³

Cal Advocates does not oppose SCE's 2019 recorded capital expenditures for pole replacements; however, Cal Advocates opposes SCE's 2020 and 2021 forecasts. Cal Advocates recommends forecast Distribution Pole Replacement expenditures of \$358.524 million in 2020 and \$437.408 million in 2021, which are lower than SCE's forecasts by \$30.145 million in 2020 and \$32.143 million in

⁵²⁰ *Id.* at 28-29.

⁵²¹ *Id.* at 31-33.

⁵²² SCE OB at 102.

⁵²³ Ex. SCE-02, Vol. 5 at 34-35.

2021.⁵²⁴ Cal Advocates recommends forecast Transmission Pole Replacement expenditures of \$102.491 million in 2020 and \$143.378 million in 2021, which are higher than SCE's forecasts by \$3.708 million in 2020 and \$3.356 million in 2021.⁵²⁵

To forecast the number of pole replacements in 2020 and 2021, Cal Advocates compares the number of poles SCE forecasted to replace in 2019 to the number SCE actually replaced that year. In 2019, SCE replaced approximately 86 percent of its distribution poles and 105 percent of its transmission poles compared to forecasted levels.⁵²⁶ Cal Advocates applies these ratios to SCE's forecast number of pole replacements for 2020 and 2021 to derive its recommended number of pole replacements.

Cal Advocates does not dispute SCE's forecast unit costs for pole replacements for 2020 and 2021 and applies these forecast unit costs to its forecast number of pole replacement to calculate its recommended capital expenditures for 2020 and 2021.⁵²⁷ Cal Advocates' recommended 2021 forecast unit costs differ from SCE's because SCE uses the 2021-2023 average unit costs rather than the 2021 forecast unit costs to calculate its 2021 forecast capital expenditures.

In rebuttal, SCE responds that Cal Advocates' reliance on recorded 2019 pole numbers is inappropriate, as 2019 activity is not representative of future years.⁵²⁸ SCE states that it had fewer pole replacements in 2019 due to the need

⁵²⁴ Cal Advocates OB at 111.

⁵²⁵ *Ibid.*

⁵²⁶ SCE OB at 100.

⁵²⁷ Ex. PAO-04 at 50 and 54.

⁵²⁸ Ex. SCE-13, Vol. 5 at 6-7.

to shift resources for the Enhanced Overhead Inspection program. SCE contends that because pole replacements were lower in 2019, many pole replacements had to be shifted to later years. SCE also argues that Cal Advocates' methodology is flawed because: (1) Cal Advocates' forecast methodology inconsistently applies 2019 pole replacement count data to the 2020 and 2021 forecasts but does not also apply 2019 recorded unit costs; and (2) Cal Advocates' use of the 2021 forecast unit costs instead of the 2021-2023 average forecast unit costs for the 2021 capital expenditure forecasts would result in underestimating the costs that SCE will incur during the GRC period.⁵²⁹

We find that SCE provides adequate justification for its pole replacement forecasts. Cal Advocates provides no explanation as to why 2019 activity might be representative of activity for 2020 and 2021. SCE provides a reasonable justification for why 2019 costs were lower than forecast and why the 2019 level of activity is not likely to be representative of 2020 and 2021 activity.

SCE explains that changes in remediation timeframe requirements adopted by the Commission drive a significant increase in the number of pole replacements. In D.17-12-024, the Commission changed the timeframe for utilities to take corrective actions on potential safety hazards and potential violations of GO 95 in high fire-threat areas and, with limited exceptions, required that the updated requirements be fully implemented in Tier 3 by September 1, 2018 and in Tier 2 by June 30, 2019.⁵³⁰ Under the new requirements, SCE must remediate overhead utility facilities, including poles, that create a fire risk located in Tier 3 within six months and Tier 2 within twelve months.⁵³¹

⁵²⁹ *Id.* at 7-8.

⁵³⁰ D.17-12-024 at 154-155, OP 4.

⁵³¹ *Id.* at 34-35; GO 95, Rule 18.

Previously, the required timeframes for remediation were between 12 and 59 months for Tier 3 pole replacements and 59 months for Tier 2 pole replacements.⁵³² In adopting these new requirements, the Commission stated: “To the extent a utility incurs significant costs to comply ... we conclude that the costs are offset by the substantial public-safety benefits of reducing the risk of utility-associated wildfires occurring in Tier 2 (elevated) and Tier 3 (extreme) fire-threat areas.”⁵³³

We find SCE’s forecast level of pole replacements to be well-supported and reasonable in light of the need for SCE to comply with these new requirements. We also find that SCE provides adequate justification for its forecast unit costs. Therefore, we approve SCE’s requested 2020 and 2021 capital expenditures for Distribution and Transmission Pole Replacements, as well as SCE’s unopposed 2019 recorded capital expenditures for these activities.

We also approve SCE’s unopposed request to continue the two-way Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA), which includes capital-related revenue requirements for the Pole Loading Program and Deteriorated Pole Program and operating expenses for the Pole Loading Program.⁵³⁴ Continuation of the PLDPBA ensures that any over- or under-collection for pole replacements pursuant to these programs will be returned to, or recovered from, customers. As in the 2015 and 2018 GRCs, the level of expenditures to be recovered in the PLDPBA over the 2021 GRC period shall be capped at 15 percent above authorized levels.⁵³⁵

⁵³² Ex. SCE-02, Vol. 5 at 10.

⁵³³ D.17-12-024 at 36-37.

⁵³⁴ Ex. SCE-02, Vol. 5 at 55; Ex. PAO-04 at 44.

⁵³⁵ See Ex. SCE-07, Vol. 1 at 42-43.

15.2.2. Joint Pole Credits

Joint capital pole credits are amounts SCE receives when another utility purchases an interest in a new or existing pole.⁵³⁶ SCE derives its forecast for joint pole capital credits by using the 2018 average amount billed per pole and multiplying this amount by the pole replacement quantities for the forecast period.⁵³⁷

Cal Advocates does not oppose SCE's recorded joint pole credits for 2019. Cal Advocates recommends forecast credits of \$113.129 million for 2020 and \$137.701 million for 2021, which is an increase over SCE's forecasts by \$10.354 million in 2020 and \$15.348 million in 2021.⁵³⁸ Cal Advocates divides SCE's 2019 recorded credits by the 2019 recorded number of pole replacements to calculate a credit per pole of \$3,461. Cal Advocates then applies this credit per pole to its recommended number of pole replacements for 2020 and 2021 to calculate its forecast credits for 2020 and 2021.

Cal Advocates' credit per pole calculation is based on dividing the total dollars billed in a calendar year with the total pole replacements in a calendar year. In contrast, SCE's credit per pole calculation is based on an analysis of 2018 work order total credits and the total number of poles replaced under each work order regardless of whether the pole replacement was completed in 2018 or a prior year.⁵³⁹ SCE argues that Cal Advocates' method is not an accurate method of calculating the credit per pole replacement because there are timing

⁵³⁶ Joint owners include other Investor-Owned Utilities, Competitive Local Exchange Carriers, Incumbent Local Exchange Carriers, and Publicly Owned Utilities.

⁵³⁷ Ex. SCE-02, Vol. 5E at 45.

⁵³⁸ Ex. PAO-04 at 58.

⁵³⁹ Ex. SCE-13, Vol. 5 at 10.

differences between when a pole is replaced and when the joint owners are billed. For example, if SCE billed a joint owner \$4,000 in 2018 for one pole replaced in 2017 and one pole replaced in 2018, SCE would include in its calculation a credit of \$2,000 per pole. Under Cal Advocates' methodology, only the 2018 calendar year billings and pole replacements would be included yielding a credit of \$4,000 per pole.

We agree that Cal Advocates' methodology would not yield an accurate credit per pole replacement forecast because it does not take into account the timing difference between when a pole is replaced and receipt of the pole credit from the joint owner. We find that SCE's methodology for calculating the average credit per pole is more likely to yield an accurate forecast. Since we also approve SCE's forecast number of pole replacements discussed above, we find reasonable and approve SCE's 2020 and 2021 forecast joint pole credits. We also approve SCE's unopposed 2019 recorded joint pole credits.

16. Vegetation Management

The Vegetation Management Program (VMP) includes pre-inspection, tree trimming, and tree removal for the more than 900,000 trees located in proximity to SCE electric facilities.⁵⁴⁰ In addition, the program implements activities such as pole brushing, commercial orchard topping, and weed abatement.⁵⁴¹

The O&M forecast for the Vegetation Management Program is presented within the following areas: (1) Routine Vegetation Management, (2) Dead, Dying, and Diseased Tree Removal, and (3) Wildfire Vegetation Management through the Hazard Tree Management Program (HTMP). SCE's combined TY

⁵⁴⁰ Routine pre-inspection and tree trimming activities are conducted on an annual cycle. (See Ex. SCE-02, Vol. 6A at 13 and 23.)

⁵⁴¹ Ex. SCE-02, Vol. 6A at 4.

O&M 2021 forecast for these activities is \$316.527 million.⁵⁴² Included in this amount is \$105.492 million attributed to increased compensation for tree trimmers resulting from Senate Bill (SB) 247 (Stats. 2019),⁵⁴³ which SCE provided through update testimony.⁵⁴⁴ SCE also proposes a new two-way balancing account to record the difference between authorized and recorded vegetation management O&M expenses.⁵⁴⁵

Cal Advocates recommends a combined reduction of \$34.947 million to SCE's forecasts for Routine Vegetation Management and Wildfire Vegetation Management activities, based on arguments that SCE failed to justify its TY forecast and failed to provide historical expenses to evaluate against its TY forecast, respectively.⁵⁴⁶

TURN recommends a reduction of \$35.450 million to SCE's forecast for Wildfire Vegetation Management through the HTMP.⁵⁴⁷ TURN argues the HTMP is a discretionary program that supplements SCE's other compliance programs; that removing tens of thousands of green trees every year is excessive to address the less than 200 tree-caused circuit interruptions in High Fire Risk Areas (HFRA) per year; and that SCE's forecast number of assessments in this case significantly exceeds sworn statements SCE made in its recent 2020-2022

⁵⁴² SCE OB at 103. Note: This amount reflects SCE's AB 560 adjustment of \$47,000 discussed in Update Testimony. (See Ex. SCE-02, Vol. 6A at 4; Ex. SCE-52A2E2, Appendix C at C9.)

⁵⁴³ SB 247 mandates all qualified line clearance tree trimmers be paid no less than the prevailing wage rate for a first period apprentice electrical utility lineman, as determined by the Director of Industrial Relations. (See Pub. Util. Code § 8386.6(b).)

⁵⁴⁴ Ex. SCE-24 and Ex. SCE-24E.

⁵⁴⁵ Ex. SCE-02, Vol. 6A at 38.

⁵⁴⁶ Ex. PAO-06 at 47 and 49.

⁵⁴⁷ Ex. SCE-54 at 130.

WMP.⁵⁴⁸ TURN does not take a position on SCE's other proposed Vegetation Management Program activities.⁵⁴⁹

Both Cal Advocates and TURN oppose the program-wide vegetation management increases SCE provides in update testimony, arguing that the forecast cost increases exceed the Commission prescribed scope for update testimony,⁵⁵⁰ and that SCE's estimate came too late for any party to review and verify. Cal Advocates and TURN recommend these costs be recorded in a memorandum account to be reviewed for reasonableness in a future application or GRC.⁵⁵¹

A summary of party positions is provided in the table below (2018 \$000):⁵⁵²

⁵⁴⁸ TURN OB at 67-81.

⁵⁴⁹ *Id.* at 66.

⁵⁵⁰ *Id.* at 350-358.

⁵⁵¹ *Id.* at 355-357; PAO OB at 127.

⁵⁵² Ex. SCE-13, Vol. 6E2 at 4; Ex. SCE-24E at 3.

Vegetation Management Program Activity	Recorded 2018	2021 Forecast			
		SCE Rebuttal Position	Cal Advocates	TURN	SCE Update Testimony
Routine Vegetation Management (Distribution)	103,257	107,012	103,257	N/A	178,203
Routine Vegetation Management (Transmission)	10,379	12,760	12,760	N/A	15,687
Dead, Dying, and Diseased Tree Removal	35,621	35,120	35,120	N/A	45,559
Wildfire Vegetation Management	5	56,188	25,052	20,738	77,125
Total Vegetation Management Costs	149,262	211,081	176,189	N/A	316,573

Intervenor recommendations are based on SCE's requested O&M amounts prior to update testimony being served. For the reasons discussed below, we find that SCE's updated forecast for VMP activities presented in update testimony exceeds the Commission prescribed scope for update testimony. Therefore, the following sections address SCE's request for its VMP activities based on SCE's rebuttal position.

16.1. Routine Vegetation Management

Routine Vegetation Management includes the cost to comply with current regulations and Commission guidance for maintaining clearances around electric transmission and distribution assets in HFRA and non-HFRA.⁵⁵³ The maintenance of vegetation in proximity to distribution and transmission lines

⁵⁵³ Ex. SCE-02, Vol. 6A at 12-16.

generally follows the same processes, including pre-inspection, the trimming or removal of trees, and quality assurance.⁵⁵⁴

SCE states it spent \$149.262 million on VMP activities in 2018, compared to the \$76.140 million requested and authorized in the 2018 GRC. SCE identifies the largest incremental cost driver over the 2018-2020 period to be implementing expanded CPUC-recommended minimum clearance distances,⁵⁵⁵ including increases to the minimum recommended clearance distance for distribution lines (from 12 inches to 48 inches) and transmission lines (from 10-20 feet to 30 feet) in HFRA's.⁵⁵⁶ SCE also identifies third-party cost increases and new program enhancements⁵⁵⁷ as additional cost drivers for Routine Vegetation Management.⁵⁵⁸

SCE's 2021 TY O&M forecast, as reflected in rebuttal testimony, includes \$107.012 million for distribution routine vegetation maintenance and \$12.760 million for transmission routine vegetation maintenance.⁵⁵⁹ SCE's forecast for tree trimming and removal activities was based on modeling assumptions for HFRA's and non-HFRA's that incorporate current clearance standards, trimming contractors' estimates, as well as executed contract rates; distribution pre-inspection forecasts based on 2018 recorded costs, with updates

⁵⁵⁴ *Id.* at 20 and 26.

⁵⁵⁵ *Id.* at 12.

⁵⁵⁶ *See* D.09-08-029; D.12-01-032; and D.17-12-024.

⁵⁵⁷ Specifically, a compliance and support office with personnel that handle work scheduling, event expediting, quality assurance, light detection and ranging technology analysis, and analytical support for reporting and performance management. (*See* Ex. SCE-02, Vol. 6A at 10 and 19.)

⁵⁵⁸ Ex. SCE-02, Vol. 6A at 18-20.

⁵⁵⁹ Ex. SCE-13, Vol. 6E2 at 3.

to reflect increases in inventory and inspection prices; transmission pre-inspection forecasts based on the cost to fly and translate LiDAR⁵⁶⁰ for field usage; and quality assurance based on the number of inspectors and hours required.⁵⁶¹

Cal Advocates recommends \$103.257 million for routine distribution vegetation management, a \$3.755 million reduction from SCE's request. Cal Advocates highlights the uncertainties in SCE's distribution forecast, and expresses concerns regarding SCE's justification for recorded Routine Vegetation Management costs. Based on these forecast uncertainties, Cal Advocates recommends using 2018 recorded costs as the basis for the TY forecast and the establishment of a two-way Vegetation Management Balancing Account to track any expenses above or below this amount.⁵⁶² Cal Advocates states it investigated, reviewed, and evaluated SCE's TY 2021 forecast for Transmission Routine Vegetation Management and found this forecast reasonable.⁵⁶³

In response, SCE argues that: (1) 2018 does not include expanded vegetation clearance activity, and therefore is not representative of the Distribution Routine Vegetation Management work SCE anticipates to perform in 2021; (2) there is a discrepancy in Cal Advocates' opposition to the Distribution Routine Management Forecast and non-opposition to the Transmission Routine Vegetation Management forecast, since both forecasts use the same itemized methodology; (3) Cal Advocates has not identified any actual

⁵⁶⁰ LiDAR is a surveying method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. (See Ex. SCE-02, Vol. 6 at 23.)

⁵⁶¹ Ex. SCE-02, Vol. 6A at 20-22 and 26-28.

⁵⁶² Ex. PAO-06 at 47-49.

⁵⁶³ PAO OB at 123.

defects in SCE's forecast methodology; and (4) Cal Advocates' observation about the uncertainty in SCE's forecast underscores the need for a two-way balancing account, not a reduction of the forecast.⁵⁶⁴

In D.17-12-024, the Commission increased vegetation clearances for areas located within the CPUC's High Fire-Threat District map, with a requirement that full compliance be achieved in Zone 1 and Tier 2 areas no later than June 30, 2019.⁵⁶⁵ Because SCE began its expanded clearance activity in 2019,⁵⁶⁶ we agree that 2018 is not expected to reflect the increased work inventory under the new clearance requirements. Further, Cal Advocates does not actually dispute any aspect of SCE's forecast methodology for Distribution Routine Vegetation Management (which, as SCE notes, uses a similar itemized methodology as SCE's forecast for Transmission Routine Vegetation Management). SCE's estimates appear reasonable and are further supported by the amount of work SCE performed during the first two quarters of 2019.⁵⁶⁷ Therefore, we find reasonable and adopt SCE's O&M forecast for Distribution Routine Vegetation Management activities.

SCE's O&M forecast of \$12.760 million for Transmission Routine Vegetation Management activities is uncontested in this proceeding. We find reasonable and adopt SCE's uncontested forecast for Transmission Routine Vegetation Management activities.

⁵⁶⁴ Ex. SCE-13, Vol. 6 at 7-10.

⁵⁶⁵ See D.17-12-024 at 132.

⁵⁶⁶ Ex. SCE-13, Vol. 6 at 7-8.

⁵⁶⁷ Ex. SCE-02, Vol. 6A at 21.

16.2. Dead, Dying, and Diseased Tree Removal

SCE removes trees that are dead, dying, or diseased and that are at risk of coming into contact with SCE electric facilities. SCE states it did not seek cost recovery for these activities in base rates as part of its 2018 GRC, since the removal of dead, dying, and diseased trees from bark beetle and drought had greatly decreased since the filing of SCE's 2015 GRC, but has included drought-related remediation as part of forecast O&M costs consistent with SCE's current request for a single VMP balancing account. Further, SCE states remediation costs under this program have increased from 2014-2018, corresponding with the impact of successive years of drought, and that in 2018 SCE recorded incremental bark beetle costs to the Drought Catastrophic Event Memorandum Account. SCE's TY O&M forecast of \$35.120 million for the removal of dead, dying, or diseased trees is based on 2018 recorded costs.

We find reasonable and approve SCE's uncontested forecast for these activities.

16.3. Wildfire Vegetation Management Through the HTMP

The HTMP builds upon proposals in SCE's GSRP⁵⁶⁸ and WMP filings to assess the site and structural condition of healthy trees in HFRA's that SCE believes pose a risk to its electric facilities and potentially lead to ignitions and outages. SCE indicates these trees could be located up to 200 feet on either side of SCE's facilities (compared to the current four-foot clearance compliance requirement for HFRA's⁵⁶⁹), at any place where a tree is taller than its distance

⁵⁶⁸ In D.20-04-013, the Commission adopted a GSRP settlement that authorized funding for up to 22,500 tree removals through the HTMP between 2019-2020. (*See* D.20-04-013 at 29.)

⁵⁶⁹ *See* D.17-12-024.

from SCE equipment. SCE states that most vegetation-caused faults are caused by living trees, and that between 2017-2018 approximately 90 percent of Tree Caused Circuit Interruptions (TCCIs) originated from outside the CPUC compliance zone.⁵⁷⁰

SCE developed a HTMP Tree Risk Calculator to assess the site and structural condition of each tree and to prioritize the appropriate mitigation based on the risk score of each tree. Potential mitigations include complete tree removal, tree trimming, monitoring, and relying on the property owner to make safe. Because most trees to be removed through the HTMP reside on non-SCE property, SCE states that it will make every effort to contact applicable property owners and attempt to reach a mutually acceptable resolution. As a last resort, SCE states it has the authority to force a tree removal under Public Resource Code § 4295.5.⁵⁷¹

The primary cost components of this activity are broken down in the table below (Constant \$000).⁵⁷² SCE's forecast is based on an estimated 125,000 tree assessments in 2019, and upwards of 250,000 tree assessments conducted in subsequent years.⁵⁷³ The forecast also assumes that SCE will perform 100,000 mitigations (*i.e.*, tree trims) per year,⁵⁷⁴ and the removal of 20,000 trees under this program in 2021, escalating to 25,000 in 2022 and 30,000 in 2023.⁵⁷⁵

⁵⁷⁰ Ex. SCE-02, Vol. 6A at 30-34.

⁵⁷¹ *Id.* at 31-35.

⁵⁷² Ex. SCE-02, Vol. 6AE at 36, Table II-11.

⁵⁷³ Ex. SCE-02, Vol. 6A at 36-37.

⁵⁷⁴ Ex. TURN-37 at 4.

⁵⁷⁵ Ex. SCE-02, Vol. 6AE, 37, Table II-12.

Activity	TY 2021 (Constant \$000)
Tree Inspections	2,476
Tree Removals	40,661
Tree Mitigation	7,283
Property Owner Incentives	499
Program Management	5,268
Total	56,188

Cal Advocates proposes TY O&M funding of \$25.052 million for the HTMP, a \$31.136 million reduction to SCE's request. Cal Advocates asserts that SCE does not show any historical expenses for this activity to review and analyze, leading Cal Advocates to use SCE's 2019 forecast as the basis of its proposed TY funding.⁵⁷⁶

TURN proposes TY O&M funding of \$20.738 million for the HTMP, a \$35.450 million reduction from SCE's request. TURN's forecast significantly reduces the number of tree removals per year, including 4,000 trees removed in 2021; 5,000 in 2022; and 6,000 in 2023. TURN does not dispute SCE's forecast to perform 100,000 mitigations per year under HTMP.⁵⁷⁷

TURN's recommendation is premised on the following arguments: (1) in assessing the need to remove an average of 25,000 healthy trees per year under HTMP, TURN argues it is important to recognize that SCE's three other compliance-related programs already remove tens of thousands of trees per year.⁵⁷⁸ (2) TURN observes SCE's risk-informed process fails to take into account

⁵⁷⁶ Ex. PAO-06 at 47.

⁵⁷⁷ TURN OB at 68 and 75.

⁵⁷⁸ *Id.* at 69-70.

the greenhouse gas benefits lost when a healthy tree is removed.⁵⁷⁹ (3) TURN asserts removing tens of thousands of trees every year is excessive to address the historical average of 177 TCCIs per year in SCE's HFRA's. TURN also argues the risk of these 177 TCCIs are partially offset by tree trimming, that actual ignitions are a subset of TCCIs, and that there is currently no data or evidence to support the effectiveness of HTMP Tree Risk Calculator in reducing wildfire risk.⁵⁸⁰

(4) TURN points out that SCE's projected number of annual assessments under HTMP has varied considerably over the course of the proceeding, from 144,000 to 360,000.⁵⁸¹ Further, TURN highlights that SCE's 2020-2022 WMP, filed February 7, 2020, further decreases the projected volume to 75,000 assessments per year, which SCE states is "based on the average number of assessors with established availability and achievable assessment productivity."⁵⁸²

In response to Cal Advocates, SCE asserts there has been historical information presented as part of this proceeding, the GSRP, and SCE's 2020 WMP, all of which support SCE's HTMP forecast. SCE also asserts it provided key data regarding 2019 activity through numerous data requests, and that Cal Advocates' argument provides little analysis on SCE's actual forecast methodology.⁵⁸³

SCE provides the following arguments in response to TURN's position: (1) SCE asserts TURN's proposal to remove 5,000 trees is arbitrary and based on a flawed analysis of TCCIs, which SCE states extend outside the GO 95

⁵⁷⁹ *Id.* at 71-72.

⁵⁸⁰ *Id.* at 72-76.

⁵⁸¹ *Id.* at 77-78.

⁵⁸² Ex. TURN-36 at 157.

⁵⁸³ Ex. SCE-13, Vol. 6 at 12-14.

mandated clearance areas and are significantly larger than the numbers cited by TURN; (2) SCE clarifies that the removal of green trees under HTMP does not necessarily equate to the removal of healthy trees, as trees marked for removal may show signs of disease, root rot, cracks in its trunk, etc.; (3) SCE asserts the HTMP uses a balanced, risk-informed methodology to reduce ignition risk, including the prioritization of circuits and tree assessments in areas with the highest risk scores and the evaluation of individual trees using the HTMP Tree Risk Calculator; (4) SCE states that the HTMP Tree Calculator was developed using industry methodology set forth by the International Society of Arboriculture (ISA) Tree Risk Assessment Qualification, and that each tree will be assessed by an ISA Certified Arborist; and (5) SCE asserts the targeted level of 75,000 assessments in its 2020 WMP was a minimum goal, and does not reflect the annual 250,000 assessments SCE can achieve.

We adopt a 2021 TY O&M budget of \$24.085 million for Wildfire Vegetation Management through the HTMP. The specific cost components of the approved O&M budget are depicted in the table below (Constant \$000) and include the assessment of 75,000 trees per year;⁵⁸⁴ SCE's forecast for the volume and cost of tree mitigations taken in proportion to the revised number of tree assessments;⁵⁸⁵ an assumed tree failure and removal rate of 11 percent;⁵⁸⁶ and

⁵⁸⁴ Assuming SCE's projected hourly rate and assessment work hours.

⁵⁸⁵ For 2021, SCE forecasts 100,000 tree mitigations based on an assumed 250,000 tree assessments (*i.e.*, 40 percent of all trees assessed are forecast to require trimming). (*See* Ex. SCE-02, Vol. 6A WP at 183). Applying this percentage to 75,000 tree assessments results in an estimated 30,000 trees to be mitigated per year.

⁵⁸⁶ Based on 75,000 tree assessments and using SCE's Excel Workpapers. (*See* Ex. SCE-02, Vol. 6A WP at 180-181.)

property owner incentives and Program Management costs corresponding to the revised scope of tree removals.⁵⁸⁷

Activity	TY 2021 Constant (\$000)
Tree Inspections	2,476
Tree Removals	16,773
Tree Mitigation	2,185
Property Owner Incentives	206
Program Management	2,445
Total	24,085

The approved HTMP TY O&M budget is based on our consideration of two main facts: first, SCE's 2020-2022 WMP decreases the annual volume of targeted HTMP assessments from SCE's prior WMP, from 125,000 to a projected 75,000 annual assessments over the 2020-2022 timeframe. In describing the reason for the decrease, SCE's 2020-2022 WMP identifies three main factors: (1) 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"; (2) variances in the productivity rate of trees assessed per day due to differences in terrain and tree density; and (3) delays in projected 2019 tree removals that resulted in a backlog of 10,000 trees requiring removal, in addition to high demand for tree pruning/removal crews throughout the state.⁵⁸⁸ While SCE attempts to argue in this GRC that the 75,000 assessments was meant to be a minimum goal, reflective of 2020 conditions, SCE largely fails to address any of the underlying reasons that led SCE to lower its WMP forecast in the first

⁵⁸⁷ See Ex. SCE-02, Vol. 6A WP at 186.

⁵⁸⁸ Ex. TURN-36 (Excerpts from SCE's 2020-2022 WMP) at 157.

place, in a filing that was submitted several months after SCE's 2021 GRC application and supporting testimony. Absent sufficient justification explaining the discrepancy between its WMP and GRC forecasts, we find it reasonable and in ratepayers' best interest to adopt the more conservative forecast.

Second, as part of the GSRP settlement SCE agreed to "participate in a study to evaluate the need for and effectiveness of its current risk calculator in promoting tree removal to reduce wildfire ignition risks, considering other mitigation measures by Southern California Edison."⁵⁸⁹ At the time opening briefs were filed in this proceeding the final results of the study were still pending.⁵⁹⁰ Until the final results of this study are made available, or SCE has presented data demonstrating the positive impact of the HTMP on the observed rate of TCCIs, we believe a more modest continuation of the HTMP to be prudent.

Lastly, SCE forecasts a 5-12 percent failure rate from tree assessments in HFRAs, and indicates the failure rate was closer to 12.4 percent during 2019. Other than noting SCE's projected rate of failure varied through the course of the proceeding,⁵⁹¹ no party specifically disputed the 5-12 percent failure rate. SCE's 2019 data indicates a high number of trees marked for removal (16,078) but a low number of trees actually removed (5,917);⁵⁹² however, SCE also provides data demonstrating a higher rate of tree removal from Oct. 2019 through May 2020, indicating that at least some of the initial delays attributed to the tree removal

⁵⁸⁹ D.20-04-013 at 18.

⁵⁹⁰ TURN OB at 76.

⁵⁹¹ *Id.* at 77-78.

⁵⁹² SCE attributes the tree removal backlog to onboarding, permitting, and weather delays. (*See* Ex. SCE-13, Vol. 6, Appendix A at A37-A38.)

backlog have been resolved. Based on the data presented in this proceeding, and considering the number of tree removals authorized under the GSRP settlement,⁵⁹³ we assume a tree failure rate of 11 percent, or the removal of 8,250 trees per year under the HTMP.

16.4. Vegetation Management Update Testimony

In update testimony, SCE requests a combined increase to its VMP activities of \$105.492 million, increasing its total VMP request from \$211.035 million to \$316.527 million. SCE attributes the increase in vegetation management costs to the execution of new contracts with vegetation management service providers, as well as the passage of SB 247, which requires increased compensation for tree trimmers.⁵⁹⁴

TURN makes the following arguments: (1) SCE's program-wide cost increases exceed the scope of what the Commission has prescribed as appropriate update testimony; (2) the cost increases are not simply a straightforward application of known and uncontroversial rate increases, but 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 vegetation management market; (3) whether or not these cost increases are appropriate requires considerably more analysis and process than the abbreviated update testimony procedure is designed to accommodate; and (4) since Pub. Util. Code § 8386.4 allows SCE to track through a Memorandum Account WMP-related costs that are not covered in a utility's revenue requirement, rejecting consideration of SCE's vegetation

⁵⁹³ The GSRP settlement includes 22,500 tree removals through the HTMP between 2018-2020, or approximately 7,500 tree removals per year. (See D.20-04-013 at 29.)

⁵⁹⁴ SCE OB at 400.

management forecast in update testimony will not prejudice SCE's ability to recover such costs if they are incurred.⁵⁹⁵

SCE asserts its updated vegetation management forecast is appropriate to include in update testimony for the following reasons: (1) SCE asserts it is not seeking to change its underlying vegetation management forecast methodology, but simply applies known changes in the cost of labor based on recent contract negotiations and governmental action, both of which are consistent with the Commission's Rate Case Plan criteria for update testimony; (2) parties had six weeks to examine the single volume of update testimony prior to evidentiary hearings for these issues, which SCE asserts was sufficient time to fully examine any issues presented by the updated forecast; and (3) SCE asserts that the increase to its vegetation management forecast is reasonable and based on a cost-competitive bid solicitation process.

The Commission's Energy Utility Rate Case Plan limits the scope of update testimony in a GRC to the following three categories:⁵⁹⁶

- (1) Known changes in cost of labor based on contract negotiations completed since the tender of the notice of intent or known changes that result from updated data using the same indexes used in the original presentation during hearings;
- (2) Changes in non-labor escalation factors based on the same indexes the party used in its original presentation during hearings; and
- (3) Known changes due to governmental action such as changes in tax rates, postage rates, or assessed valuation.

⁵⁹⁵ TURN OB at 349-351.

⁵⁹⁶ D.07-07-004, Appendix A at A-36.

When interpreting what constitutes a ‘known change’ the Commission found in D.04-12-015 that “This authority to update is clearly intended to address the ministerial application of a change for an activity already known to be necessary, and in fact reflects better facts than were used in the original estimate.”⁵⁹⁷ The Commission then expands upon what does *not* qualify as a known change, in describing why SDG&E’s update testimony to include additional security measures adopted by the Nuclear Regulatory Commission (NRC) is out of scope:

The second and most compelling reason is that the new NRC requirements simply are not a ‘known change’ that can be updated, for example, by substituting 39 cents for the current 37 cents charged for postage. These security costs are a previously unknown and new requirement that was not anticipated in SDG&E’s filing...To find totally new mandates to be merely an update could compel us to either delay major proceedings late in the schedule or to unduly rush our review of potentially significant new actions by other government bodies. We reject SDG&E’s argument that these costs are includable as an update under Commission practices.⁵⁹⁸

SCE attempts to frame its updated VMP costs as being consistent with the Commission’s interpretation, encompassing activities known to be necessary (*i.e.*, vegetation management), while “merely applying known changes in costs.”⁵⁹⁹ While it is undisputed that vegetation management activities are necessary, as

⁵⁹⁷ D.04-12-015 at 26.

⁵⁹⁸ *Id.* at 26-27. In this decision, the Commission nevertheless went on to allow SDG&E to tentatively recover, subject to refund, the estimated new costs in question, due to compelling concerns about terrorist activities at nuclear power plants in the wake of the September 11, 2001 attacks. (*Id.* at 27 and fn. 33.)

⁵⁹⁹ SCE OB at 402.

explained below, SCE's updated forecast is not as simple and straightforward as substituting one known cost for another.

SCE's VMP update includes two components: (1) new Unit Rates⁶⁰⁰ stemming from the conclusion of a competitive bidding process in 2019, and (2) the modification of those new Unit Rates stemming from the enactment of SB 247.⁶⁰¹ Pre-SB 247 contract negotiations that occurred through the competitive bidding process encompassed a variety of market factors, including but not limited to the tight labor market for vegetation management crews in California, increased insurance premiums, and new safety standards.⁶⁰² In contrast, SB 247 changes are limited to the required minimum wage for tree trimmers, which is just one subcomponent of the Unit Rates SCE uses to forecast its VMP costs.

Because SCE uses Unit Rates (as opposed to hourly rates) to forecast its VMP costs, and pre-SB 247 Unit Rates are driven by a variety of cost increases that vendors have sought to add to their contracts, it is impossible to isolate the specific wage rate increases mandated by SB 247. Contributing to the higher Unit Rates is the fact that SCE added two relatively higher cost vendors to the calculation of its new forecast.⁶⁰³ Therefore, it is not, as SCE argues, simply a matter of substituting the existing labor rate for tree trimmers with a new, higher hourly amount, and applying that labor rate to the volumes identified in SCE's

⁶⁰⁰ Unit Rates represent a price negotiated with SCE's contractors to complete a single trim job with a standard crew, and are considered to be inclusive of not just wages and auxiliary costs, but also the contractors' overhead costs, such as vehicles, tools, administration, and insurance. (See Ex. TURN-87 at 1.)

⁶⁰¹ SCE OB at 401.

⁶⁰² Ex. SCE-55 at 1-2.

⁶⁰³ Ex. TURN-81C at 2.

previous testimony. As a result, we agree with TURN that SCE's vegetation management update forecast goes beyond the limited changes appropriate for update testimony and, given the limited record on this issue, do not have a high degree of confidence in the accuracy of SCE's updated forecast.

Further, while it is reasonable to expect some level of cost increase associated with the passage of SB 247, given the Vegetation Management Balancing Account treatment discussed below, in addition to SCE's existing ability to record vegetation management costs that are not otherwise covered in its revenue requirement through the Fire Risk Mitigation Memorandum Account,⁶⁰⁴ we are also mindful that rejecting SCE's request to consider its vegetation management update forecast in this GRC will not deprive SCE of the opportunity to seek future recovery of these costs as they are incurred.

For all of these reasons, we find SCE's Vegetation Management Update Testimony⁶⁰⁵ exceeds the limited scope for update testimony, and reject SCE's request to include these costs in the TY O&M forecast. SCE will have the opportunity to seek future recovery of SB 247-related costs through the Vegetation Management Balancing Account established in this decision.

16.5. Vegetation Management Balancing Account

SCE proposes to create a new two-way balancing account, the Vegetation Management Balancing Account (VMBA), to record the difference between: (1) authorized O&M expenses for all vegetation management activities in this proceeding (*i.e.*, Routine Transmission and Distribution Vegetation Management; Dead, Dying, and Diseased Tree Removal; and Wildfire Vegetation Management

⁶⁰⁴ As set forth in Pub. Util. Code § 8386.4(b).

⁶⁰⁵ Ex. SCE-24 and SCE-24E.

through HTMP) and (2) SCE's recorded expenses for these activities. SCE asserts that Balancing Account treatment is necessary since many of the specific programs and activities are new (most notably the HTMP and expanded clearance/pruning distances), and since SCE's risk-based methodologies continue to be refined.⁶⁰⁶

Cal Advocates recommends the establishment of a two-way VMBA, with an expense level of \$176.134 million for the 2021 TY and a requirement that SCE track and record any excess costs above its TY forecast for reasonableness review.⁶⁰⁷

TURN's primary recommendation is to reject SCE's proposal for a new VMBA, with SCE continuing to record its incremental costs in existing memorandum accounts. Alternatively, TURN recommends the establishment of a one-way balancing account to track spending up to the amount authorized by the Commission (with any spending below authorized amounts to be returned to customers), along with a companion memorandum account to track spending above the authorized amount. TURN asserts that reliance on a memorandum account for tracking above-authorized spending is consistent with PG&E's most recent gas transmission and storage rate cases; that SCE does not contend a balancing account is warranted due to vegetation management costs beyond its control; and that SCE's proposal for a two-way balancing account would inappropriately shift risk to ratepayers. If a one-way balancing account is established, TURN recommends SCE be required to establish appropriate

⁶⁰⁶ Ex. SCE-02, Vol. 6 at 38.

⁶⁰⁷ Ex. PAO-06 at 47.

sub-accounts to compare authorized and recorded spending at a more granular level.⁶⁰⁸

In response, SCE asserts (1) it is critical that the Commission not place a cap on vegetation management expenditures given the importance of these activities to mitigating wildfire risk, and at a time when the associated cost increases are uncertain and outside of SCE's control; (2) a two-way balancing account is consistent with how PG&E's and SDG&E's vegetation management activities are treated; (3) an after-the-fact reasonableness review of costs spent in excess of the vegetation management forecast adopted in this proceeding is unnecessary; however, if required, the Commission should, at a minimum, authorize a balancing account with a soft cap of 120 percent;⁶⁰⁹ (4) it is not possible to simply continue the "status quo" for spending above authorized being recorded in memorandum accounts because two of the four Fire Mitigation Memorandum Accounts have prescribed December 31, 2020 termination dates;⁶¹⁰ (5) TURN's recommendation for 'program-specific' review is unwarranted, could inhibit SCE from funding emergency needs, and would be administratively burdensome; and (6) TURN's alternative proposal is indistinguishable from SCE's alternative proposal (*i.e.*, a two-way balancing account with amounts above a specified threshold subject to retrospective reasonableness review).⁶¹¹

In considering intervenor proposals in this proceeding, we believe the creation of a single VMBA, with enhanced review at a lower cost threshold, will

⁶⁰⁸ TURN OB at 245-249 and 251-253.

⁶⁰⁹ SCE OB at 297-300.

⁶¹⁰ Including the Grid Safety and Resiliency Program Memorandum Account and the Fire Hazard Prevention Memorandum Account.

⁶¹¹ SCE RB at 158-162.

accomplish many of the same ratepayer protections without introducing the administrative complexity of creating multiple tracking accounts, for multiple vegetation management programs consisting of similar underlying activities.

We approve SCE's proposed two-way VMBA along with a requirement that recovery of recorded costs in excess of 115 percent of the authorized amount for VMP activities be made by application. For costs between 100 percent and 115 percent of the authorized amount, cost recovery may be made by a Tier 2 advice letter. This approach is generally consistent with the treatment of vegetation management costs in PG&E's TY 2020 GRC, where the Commission found that the creation of a VMBA would promote efficiency across activities that are similar, or that are expected to become similar over time; support ongoing wildfire mitigation activities, even if costs above authorized levels become necessary; allow the return of unused funds to ratepayers; and allow for enhanced review of larger cost recovery amounts.⁶¹²

17. Wildfire Management

17.1. Overview

SCE identifies utility-caused wildfire as its top public safety risk and includes a portfolio of activities in this GRC it deems critical to combat this risk.⁶¹³ As described in Section 7 (Risk-Informed Strategy), SCE's proposed wildfire mitigation activities are directly informed by, and are an evolution of, risk analysis frameworks developed across numerous Commission proceedings (including SCE's 2018 GSRP, 2018 RAMP Report, and 2019 WMP). Most of SCE's proposed wildfire mitigation activities focus or take place within SCE's High Fire

⁶¹² See D.20-12-005 at 77-79.

⁶¹³ Ex. SCE-01, Vol. 2 at 6.

Risk Area (HFRA) boundaries, which are consistent with the areas identified in the CPUC's High Fire-Threat District (HFTD) map.⁶¹⁴

Overall, SCE forecasts \$100.765 million in O&M expenses for the 2021 TY and \$4.295 billion in capital expenditures during the 2019-2023 period to implement its proposed portfolio of wildfire mitigation activities. SCE also requests the creation of a new two-way balancing account to track the difference between SCE's recorded O&M expenses and capital expenditures for wildfire mitigation-related activities (excluding vegetation management activities) and the authorized revenue requirement associated with forecast O&M and capital expenditures adopted in this proceeding.

17.2. Wildfire Covered Conductor Program

17.2.1. Party Positions

17.2.1.1. SCE Proposal

The Wildfire Covered Conductor Program (WCCP) is SCE's primary grid hardening wildfire mitigation solution in this GRC, representing over 90 percent of SCE's capital expenditure forecast for wildfire management.⁶¹⁵ Covered conductor is aluminum or copper wire covered by three layers of insulation designed to withstand incidental contact from foreign objects, such as vegetation, other debris, and even the ground in wire down events.⁶¹⁶ SCE identifies "contact from an object" followed by "equipment/facility failure" as the two largest ignition drivers on its distribution system that could lead to a potential wildfire.⁶¹⁷ SCE's GRC analysis indicates that wildfire risk associated with

⁶¹⁴ As determined by D.17-12-024, and modified by D.20-12-030.

⁶¹⁵ Ex. SCE-15, Vol. 5 at 7, Table I-4.

⁶¹⁶ Ex. SCE-04, Vol. 5A at 20.

⁶¹⁷ *Id.* at 14.

overhead distribution-level facilities can be reduced by 60 percent through the deployment of covered conductor.⁶¹⁸ SCE is seeking to deploy 6,272 cumulative miles of covered conductor between 2019-2023,⁶¹⁹ or 60 percent of the overhead conductor circuit miles in SCE's Tier 2 and Tier 3 HFRAs,⁶²⁰ for a total cost of \$3.4 billion.⁶²¹

In addition to reconductoring work, the WCCP includes 72,400 pole replacements to account for the additional weight and higher wind loading associated with covered conductor and to ensure ongoing compliance with General Order 95.⁶²² While SCE initially proposed using composite poles for all pole replacements, SCE now proposes a 60/40 percentage split using either fire-resistant wraps on wood poles or composite poles, respectively.⁶²³ Fire-resistant wraps have an incremental cost of approximately \$1,600 per pole while composite poles have an incremental cost of approximately \$5,100 per pole. As part of the WCCP, SCE also proposes to eliminate 3,200 instances where existing electrical equipment is attached to trees, for a total budget of \$93.5 million.⁶²⁴

⁶¹⁸ Ex. TURN-02, Attach. 1, question 7.

⁶¹⁹ Ex. SCE-15, Vol. 5 at 17; Ex. SCE-12, Vol. 1 at 5, Table II-1.

⁶²⁰ Tier 2 consists of areas on the CPUC Fire-Threat Map where there is an elevated risk from wildfires associated with overhead utility electric equipment, and Tier 3 consists of areas where there is an extreme risk from wildfires associated with overhead utility electric equipment. (See D.17-12-024 at 2.)

⁶²¹ \$2.648 billion over the 2021-2023 GRC period. SCE estimates the unit cost for covered conductor to be \$421k per circuit mile. SCE's \$3.4 billion WCCP forecast for 2019-2023 includes the replacement of existing bare overhead conductor with covered conductor, associated pole upgrades, and the replacement of 3,200 tree attachments. (See Ex. SCE-04, Vol. 5A at 28; Ex. SCE-15, Vol. 5 at 6-7 and 12; and Ex. SCE-54 at 190.)

⁶²² Ex. SCE-04, Vol. 5A at 28-29.

⁶²³ Ex. SCE-15, Vol. 5 at 34.

⁶²⁴ *Id.* at 20; Ex. SCE-04, Vol. 5A at 28-29.

A comparison between SCE’s 2018 RAMP Report and GRC capital expenditure forecasts for WCCP is provided below (Nominal \$000). SCE attributes the increase between the RAMP and GRC forecasts to the addition and acceleration of over 1,500 circuit miles of covered conductor and associated pole replacements within the 2019-2023 timeframe.⁶²⁵

RAMP Control/Mitigation Name	Filing Name	2019	2020	2021	2022	2023
Wildfire Covered Conductor Program	RAMP ⁶²⁶	\$60,437	\$231,501	\$278,977	\$346,187	\$417,269
	GRC ⁶²⁷	\$249,288	\$507,445	\$733,024	\$861,973	\$1,053,035
	Variance	\$188,851	\$275,944	\$454,047	\$515,786	\$635,766

17.2.1.2. Intervenors

Cal Advocates recommends the installation of 1,000 circuit miles in the 2021 TY, a reduction of 400 circuit miles from SCE’s forecast,⁶²⁸ or a 2019-2023 capital expenditure forecast of \$2.292 million for the WCCP.⁶²⁹ Cal Advocates asserts the rate of installation will be slower than SCE forecasts, and that its proposal represents a “reasonable compromise between the three-year average for 2019-2021 of about 900 circuit miles per year versus the five-year average for 2019-2023 of about 1,200 circuit miles per year.”⁶³⁰ In addition, Cal Advocates recommends using 2019 forecast data instead of 2019 recorded data on the basis it was unable to verify SCE’s 2019 recorded data.⁶³¹

⁶²⁵ *Id.* at 32.

⁶²⁶ *Id.* at Table II-8.

⁶²⁷ Reflects SCE's Rebuttal Position. (See Ex. SCE-15, Vol. 5 at 6-7, Tables I-3 and I-4.)

⁶²⁸ Ex. PAO-09 at 14.

⁶²⁹ Ex. SCE-54 at 190.

⁶³⁰ Ex. PAO-09 at 14-15.

⁶³¹ *Id.* at 13.

TURN recommends the installation of 2,500 cumulative miles of covered conductor over the 2019-2023 period.⁶³² TURN's WCCP proposal (including associated pole upgrades and the replacement of tree attachments) would result in a total capital expenditure forecast of \$892 million, covering 2019 recorded and 2021-2023 forecast capital expenditures.⁶³³ TURN's proposal is premised on the following main arguments: (1) TURN asserts its proposal would mitigate the majority of risk in SCE's HFRA's while considering affordability and cost-effectiveness thresholds; (2) TURN questions whether SCE will be able to complete the level of deployment it forecast over the rate case period; (3) TURN highlights the actual wildfire risk reduction and performance of covered conductor in the field is unknown at this time.⁶³⁴ In addition, TURN argues for reduced pole replacement and tree attachment replacement forecasts associated with the WCCP. Each of these arguments is detailed below.

Utilizing SCE's risk data and analyses, including Table II-7 of SCE's Rebuttal Testimony, TURN points to the diminishing safety returns associated with the scale of SCE's proposed covered conductor deployment. Table II-7 of SCE's Rebuttal Testimony illustrates the general consequence of wildfire risk associated with various points on the risk curve and is reproduced for reference below.⁶³⁵

⁶³² TURN OB at xvi.

⁶³³ TURN does not provide a WCCP recommendation for 2020. (See Ex. SCE-54 at 190.)

⁶³⁴ Ex. TURN-02 at 11-12.

⁶³⁵ Ex. SCE-15, Vol. 5 at 21-22.

Tranches of Cumulative Miles on Risk Curve	Average Reax Score for Tranche⁵⁰	Average Wildfire Consequence per Mile for Tranche⁵¹
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

TURN highlights the first 2,500 miles on the risk curve represent a relatively higher risk profile, or REAX Score,⁶³⁶ accounting for 94 percent of the total risk in SCE's HFRA's. These circuits also contain the greatest average wildfire consequence per mile.⁶³⁷ Based on this observation, TURN asserts SCE has not utilized its own risk analyses to appropriately target the scope and pace of covered conductor. TURN further argues that SCE's failure to target spending on the highest risk circuits, or identify affordability thresholds to determine when covered conductor deployment would be cost-prohibitive, leaves the utility unable to demonstrate that its proposal is affordable and consistent with just and reasonable rates.⁶³⁸

⁶³⁶ The consequence module of the Wildfire Risk Model was conducted by REAX Engineering. The REAX score is based on hundreds of thousands of Monte Carlo simulations to analyze the consequence of ignitions by location, with corresponding consequence estimated as a product of the number of structures burned within a modeled fire perimeter and the fire volume (acres burned) associated with that fire perimeter within the first six hours of ignition. (See Ex. SCE-15, Vol. 5 at 19, fn. 42; Ex SCE-01, Vol. 2 WP.)

⁶³⁷ TURN OB at 92-93.

⁶³⁸ *Id.* at 88.

In contrast, TURN argues the installation of 2,500 miles would focus ratepayer spending on circuits that present the greatest risk, consistent with the principles of just and reasonable ratemaking, while addressing over 90 percent of wildfire risk in SCE's HFRA's.⁶³⁹ While acknowledging SCE's proposal would address more absolute risk, TURN observes the additional circuit miles beyond TURN's proposal would still be subject to a host of wildfire mitigation measures, and that failure to deploy covered conductor in any one location does not mean that there are no mitigation measures in place for that circuit.⁶⁴⁰

TURN also asserts SCE is unlikely to be able to complete its forecast level (6,272 circuit miles) of covered conductor deployment. TURN states that, due to the associated pole installations, replacement of bare overhead conductor generally requires less labor than covered conductor, and that SCE's proposed covered conductor deployment dwarfs both historical levels of covered conductor installation as well as the utility's installation of bare conductor.⁶⁴¹

Regarding the performance of covered conductor, TURN asserts the risk reduction potential of covered conductor has yet to be validated in the field. While TURN does not believe the Commission needs to be overly cautious in this regard,⁶⁴² it argues the unknown risk potential of large-scale covered conductor

⁶³⁹ *Id.* at 90.

⁶⁴⁰ *Id.* at 97.

⁶⁴¹ Ex. TURN-02 at 21.

⁶⁴² *Id.* at 22.

deployment as well as the actual cost of installation per mile⁶⁴³ should inform the Commission's decision on the level of deployment at this time.⁶⁴⁴

TURN also observes that, despite the significant proposed expansion of covered conductor, SCE does not identify any potential redundancies that could decrease spending on other mitigations in the locations where covered conductor is deployed. Where mitigation programs overlap, TURN recommends SCE be directed to study where efficiencies can be realized, and ratepayer costs reduced, while maintaining a consistent level of safety.⁶⁴⁵

Finally, TURN recommends reductions to the pole replacement and tree attachment budgets under the WCCP. TURN asserts SCE does not explain how its decision tree logic better supports the proposed 60/40 split between fire-resistant wraps and composite poles, rather than the 75/25 split recommended by TURN. In light of SCE's failure to demonstrate, with specificity, the number of poles that require replacement, TURN recommends its forecast be adopted and SCE be directed to track the actual split between pole wrap and fire-resistant poles.⁶⁴⁶ Regarding SCE's proposed tree attachment budget, TURN states that SCE provides no risk information specific to tree attachments. Because TURN's covered conductor proposal would address circuits representing the greatest risk, TURN reasons its covered conductor proposal would also address tree attachments with the highest risk.⁶⁴⁷

⁶⁴³ While TURN does not dispute SCE's estimated unit cost for covered conductor of \$421 per circuit mile, TURN argues the cost-effectiveness of covered conductor will be further informed through actual deployment. (See Ex. TURN-02 at 22).

⁶⁴⁴ Ex. TURN-02 at 22.

⁶⁴⁵ *Id.* at 7-8.

⁶⁴⁶ TURN OB at 104-105.

⁶⁴⁷ *Id.* at 105-106.

CUE recommends the Commission reject Cal Advocates' and TURN's proposed reductions. CUE asserts SCE's ability to accomplish the scope of its proposed covered conductor program should account for the reality of current circumstances, including the substantial shift in workforce and capital resources to wildfire mitigation efforts.⁶⁴⁸ In addition, CUE asserts that TURN's cost-effectiveness argument fails to recognize that installing covered conductor on lower risk segments still reduces wildfire risk.⁶⁴⁹

17.2.1.3. SCE Response to Intervenor

SCE asserts that Cal Advocates' and TURN's proposals would retain material risk resulting from incomplete WCCP roll-out, with potentially serious consequences stemming from unmitigated wildfire risks. With respect to SCE's ability to accomplish the proposed scope of its WCCP, SCE asserts Cal Advocates' position is not based on actual evidence and should be rejected. Further, SCE states it has proven that it can expeditiously ramp up new programs, including exceeding its 2019 WMP goal (96 miles) and GRC forecast (291 miles) for covered conductor, and that it has already taken significant measures to ensure critical wildfire mitigation work is performed over the GRC period.⁶⁵⁰ SCE also asserts the execution rate for new programs is typically lower in the initiation year; that Cal Advocates' proposed reduction in 2021 would have the cumulative effect of delaying an additional 1,500 circuit miles of work in 2022-2023;⁶⁵¹ and that TURN's comparison to SCE's deployment of its

⁶⁴⁸ CUE OB at 25-26.

⁶⁴⁹ *Id.* at 25.

⁶⁵⁰ Ex. SCE-15, Vol. 5 at 35-36.

⁶⁵¹ *Id.* at 37.

Overhead Conductor Program (OCP) is misleading, since limited OCP rollout was largely a function of regulatory constraints.⁶⁵²

SCE provides the following arguments in response to TURN's recommended scope of the WCCP: (1) that the risk buydown curve is intended to prioritize the order of covered conductor deployment, not determine the amount of covered conductor installed; (2) that it is important to consider the consequences of ignoring absolute risk by focusing solely on relative risk; (3) that the Commission has already defined the appropriate scope of covered conductor by defining levels of risk in HFTDs; (4) that operational and other policy considerations warrant the installation of additional covered conductor; and (5) that SCE rigorously tested, evaluated, and benchmarked the use of covered conductor to mitigate wildfire risk. SCE also provides support for its tree attachment removal forecast and 60/40 ratio of fire-resistant pole wraps to composite poles. Each of these arguments is detailed below.

SCE asserts TURN's relative-risk-based proposal inappropriately uses SCE's risk prioritization curve for scoping purposes,⁶⁵³ and that less cost-effective should not be confused with not cost-effective. SCE explains the risk buydown curve measures relative risk and is intended to help SCE prioritize the deployment of covered conductor, not set the total scope of deployment.⁶⁵⁴

SCE stresses the potentially serious impacts to public safety, land, and a significant number of public structures that could result by focusing on relative risk rather than absolute risk. SCE observes that, due to the limitations of REAX fire propagation modeling (*i.e.*, the assumption that wildfires last only 6 hours),

⁶⁵² *Id.* at 30-31.

⁶⁵³ Ex. SCE-15, Vol. 5 at 17.

⁶⁵⁴ *Id.* at 19-20.

the average potential wildfire consequence per mile is likely a conservative value.⁶⁵⁵ Because the risk reduction model is heavily weighted towards acres burned, SCE also notes that focusing on the structures impacted by a potential wildfire would produce a much “flatter” REAX curve.⁶⁵⁶

Beyond the structures impacted by a potential wildfire, SCE stresses that hundreds of thousands of people living in SCE’s HFRA that would be excluded from the protection of WCCP, including some of SCE’s most vulnerable residential customers and essential services facilities. SCE estimates that more than eight hundred critical care customers and approximately 5,000 critical infrastructure facilities would be left out if TURN’s proposal were adopted.⁶⁵⁷

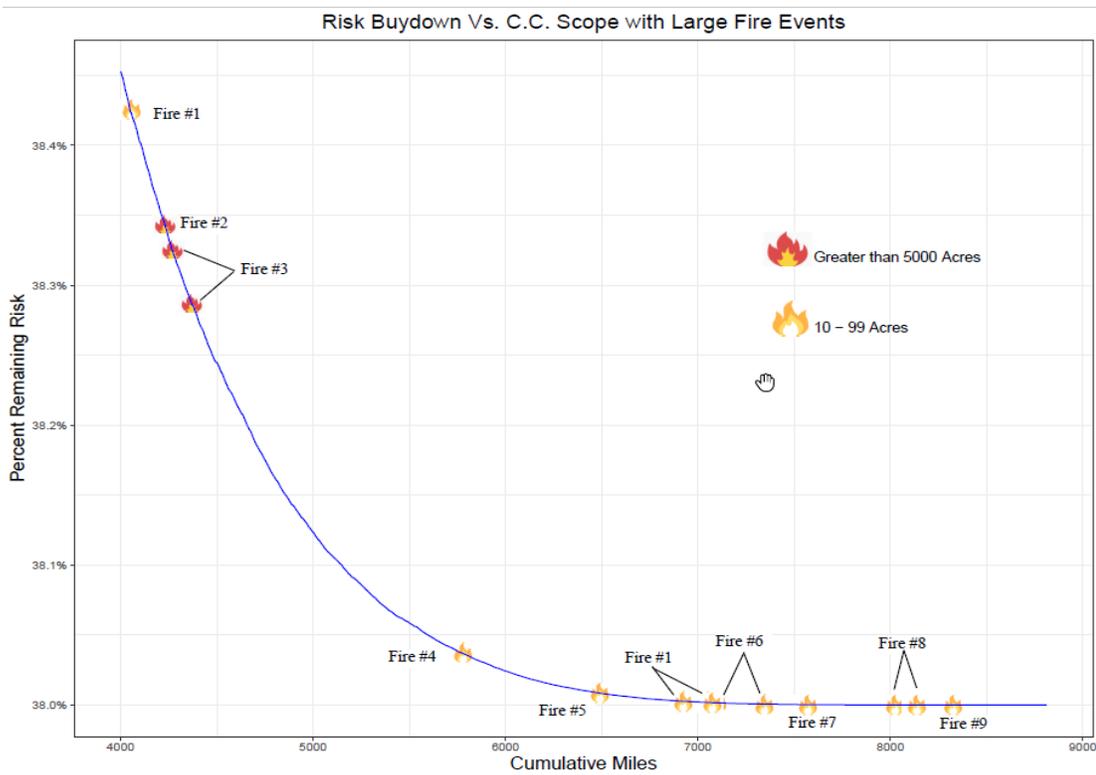
SCE also argues TURN’s proposal would leave parts of SCE’s distribution system uncovered where large fires have previously occurred. To support this point, SCE overlaid large historical reportable ignitions which occurred since 2014 on the risk buydown curve.⁶⁵⁸ The resulting figure is provided below for reference.

⁶⁵⁵ *Id.* at 25.

⁶⁵⁶ *Id.* at 16.

⁶⁵⁷ *Id.* at 24.

⁶⁵⁸ Ex. SCE-15, Vol. 5 at 25, Figure II-3.



Referencing the figure above, SCE states there have been three recent ignitions greater than 5,000 acres which occurred up to the 4,500 mile-mark, demonstrating the presence of actual risk beyond TURN’s proposal.⁶⁵⁹

Because WCCP will be deployed almost exclusively in areas designated as Tier 2 and Tier 3 in Commission-defined HFTDs,⁶⁶⁰ SCE argues the Commission has already decided that the areas SCE will deploy covered conductor are inherently risky.⁶⁶¹

Regarding TURN’s assertion that covered conductor has not been validated in the field, SCE asserts it carefully researched, evaluated, benchmarked, and vetted the use of covered conductor to mitigate wildfire risk,

⁶⁵⁹ *Id.* at 25.

⁶⁶⁰ *See* D.17-12-024.

⁶⁶¹ SCE OB at 117-118.

which included examples of covered conductor deployed in the field. SCE cites to the success of covered conductor deployment in other countries as one of the factors that led SCE to target covered conductor in this GRC. For example, following devastating bushfires in Australia, the 2009 Victorian Bushfires Royal Commission issued a report listing a variety of recommendations, among which were installing covered conductor and removing trees outside of the clearance zone.⁶⁶² SCE has also begun analyzing early data associated with its covered conductor rollout, and states there have been no ignitions to date on distribution lines where bare conductor was replaced with covered conductor.⁶⁶³

Even if the Commission were to determine that there is an “acceptable” amount of risk to leave unmitigated by authorizing a lower number of covered conductor circuit miles, SCE claims the installation of additional miles will still be necessary to efficiently achieve a lower target. Because the risk buydown curve is based on a circuit segment basis, not a complete circuit basis, SCE asserts that operational realities may require the installation of additional covered conductor to the next continuous structure with equipment, or the next structure that is a dead-end. This may occur, for example, when covered conductor meets bare conductor, and the extra weight and associated wind loading of covered conductor (causing a pole imbalance) cannot easily be addressed through guying. SCE asserts that accounting for the operational design realities of deploying covered conductor, and capturing PSPS benefits for customers, necessarily increases the number of miles that would be covered strictly pursuant to the risk analysis by an estimated 20 percent.⁶⁶⁴

⁶⁶² Ex. SCE-15, Vol. 5 at 32.

⁶⁶³ *Ibid.*

⁶⁶⁴ SCE OB at 125-127.

Finally, SCE argues a 60/40 ratio of fire-resistant pole wraps to composite poles should be adopted, and all tree attachments removed. SCE asserts its proposed 60/40 percentage split is based on a decision tree logic that SCE uses to determine which fire-resistant material is appropriate to deploy, and is consistent with SCE's 2020-2022 WMP, while TURN's proposed 75/25 percentage split is arbitrary and unsupported.⁶⁶⁵ Regarding the removal of tree attachments, SCE states there are operational efficiencies gained by replacing tree attachments together with covered conductor, which is why SCE included the activities together. However, to the extent reductions are made to SCE's covered conductor request SCE continues to recommend removal of all tree attachments in its service territory, which SCE asserts continue to be at risk of becoming diseased or dying, and by their very nature pose a unique wildfire risk.⁶⁶⁶

17.2.2. Discussion

Catastrophic wildfires have become a regular occurrence in California. Fueled by the effects of climate change and severe drought conditions, these wildfires have grown in scale and frequency over the past decade, resulting in loss of life and property, ecological devastation, increases in future fire risk, and the accumulation of substantial costs. In SCE's territory, the increasing magnitude of wildfires was brought to light in 2017 and 2018, as the state was subjected to unprecedented strong winds.⁶⁶⁷ Over this same timeframe, the State and the Commission have taken a number of steps to further protect the state and its residents from utility-caused wildfires including, among others, the establishment of a framework and guidance for the submission of annual utility

⁶⁶⁵ *Id.* at 130.

⁶⁶⁶ *Id.* at 129-130.

⁶⁶⁷ Ex. SCE-04, Vol. 5A at 13.

wildfire mitigation plans; the development of a statewide fire-threat map and delineation of areas subject to additional fire-safety regulations; the adoption of updated guidelines to mitigate wildfire risk and the impact on customers when a utility considers de-energizing the electric grid; authorization of a non-bypassable charge to support California's Wildfire Fund; and the establishment of an emergency disaster relief program for electric, natural gas, water and sewer utility customers.

While the need to prevent utility-caused wildfires remains critically important, Commission decisions in general rate case proceedings are, above all, guided by Pub. Util. Code §§ 451 and 454, which require SCE to “promote the safety, health, comfort, and convenience of its patrons, employees, and the public” while including only “just and reasonable” charges in its rates.⁶⁶⁸ In consideration of this statutory obligation, as well as the significant threats that wildfires pose to the state of California, and to SCE customers in particular, we authorize funding sufficient to support the deployment of 4,500 circuit miles of covered conductor. In addition, SCE is provided the opportunity to deploy additional covered conductor circuit miles above the level approved in this decision subject to after-the-fact reasonableness review. We reach this conclusion based on the following reasons:

First, the deployment of 4,500 circuit miles⁶⁶⁹ would address 98 percent of the wildfire risk in SCE's HFRA's at a cost that is \$1.5 billion less than SCE's request. Even taking into consideration that the REAX model may have used conservative consequence values, and that focusing on the structures impacted

⁶⁶⁸ Section 451.

⁶⁶⁹ Includes 3,750 circuit miles based on the first three tranches of cumulative miles on SCE's risk buydown curve, plus a 20% adder to account for operational design considerations.

would produce a “flatter” risk curve, it is clear that this level of deployment would efficiently utilize one of the more expensive wildfire mitigation measures available (aside from undergrounding) to address SCE’s highest-risk segments at a fraction of the cost. While we agree with TURN that covered conductor should target SCE’s highest risk circuits, our assessment of the average REAX score by tranche along SCE’s risk buydown curve leads us to conclude that significant risk remains up to the 3,750 circuit mile level.

In contrast, SCE’s full 6,272 circuit mile request is based solely on the maximum amount of covered conductor SCE believes it can install over this GRC period. By failing to consider how the range of available cost-effective mitigation measures correspond with SCE’s own circuit segment risk calculations, we find that SCE has not cost-effectively targeted its covered conductor proposal or demonstrated that its request is consistent with just and reasonable rates.

To be clear, we are not foregoing the possibility that additional funding for covered conductor may be warranted in the future. Given the level of funding approved for covered conductor deployment in this decision, we hope the performance of covered conductor exceeds SCE’s own projections and is used to inform future requests. As discussed in Section 17.13 (Wildfire Risk-Mitigation Balancing Account), this decision establishes a cost recovery mechanism that would allow SCE to install additional covered conductor miles above the 4,500 circuit-mile level, including within this GRC period, subject to after-the-fact reasonableness review; however, SCE will have the burden to affirmatively establish further covered conductor deployment is justified based upon its most recent WMP and up-to-date circuit segment risk calculations. To the extent SCE’s WMP identifies alternative, more cost-effective wildfire mitigation measures in place of additional covered conductor, SCE is already authorized to

track these costs through the Wildfire Mitigation Plan Memorandum Account⁶⁷⁰ or the Fire Risk Mitigation Memorandum Account, and must adjust its wildfire mitigation work accordingly and promptly.⁶⁷¹

Second, as observed by TURN, HFRAAs not addressed by covered conductor will still be subject to a host of other wildfire mitigation measures; while some distribution lines may be uncovered, they will not be unmitigated. The majority of wildfire mitigation measures presented in this GRC are approved at the levels requested by SCE, including activities such as targeted undergrounding, fusing mitigation, HFRA sectionalizing devices, the Enhanced Overhead Inspections and Remediation Program, among others, and are expected to apply to the critical care customers and critical infrastructure facilities that SCE argues are left out of TURN's proposal. We note that critical care customers and facilities will also benefit from lower long-term bill impacts associated with reduced covered conductor deployment.

Third, the installation of covered conductor does not guarantee that utility-caused ignitions will not occur. SCE argues its proposed covered conductor deployment will address more absolute risk, and that a single ignition prevented could save the State and customers billions of dollars.⁶⁷² While true, even after covered conductor is installed an estimated 40 percent of wildfire risk remains.⁶⁷³

⁶⁷⁰ The Wildfire Mitigation Plan Memorandum Account is intended to track costs to implement an electrical corporation's approved Wildfire Mitigation Plan. (See Pub. Util. Code § 8386.4 (a); also, D.19-05-038, OP 18.)

⁶⁷¹ The Fire Risk Mitigation Memorandum Account is intended to track incremental fire-risk mitigation costs "not otherwise covered in the electrical corporation's revenue requirements." (See Pub. Util. Code § 8386.4 (b)(1); also, March 12, 2019 Energy Division Disposition of SCE Advice Letter 3936-E-A.)

⁶⁷² SCE RB at 82.

⁶⁷³ Ex. TURN-02, Attach. 1, question 7.

The fact that covered conductor does not, in and of itself, completely eliminate the risk of ignition, further highlights the need for SCE to present a more comprehensive evaluation of each circuit segment to determine the most appropriate and cost-effective mitigation measure(s) for that segment.

Fourth, while SCE performed rigorous testing, engineering, and benchmarking evaluations on the performance of covered conductor, we expect the actual performance and estimated unit cost of covered conductor to be further informed through the process of larger-scale deployment. As of the end of 2019, SCE had installed 372 circuit miles of covered conductor.⁶⁷⁴ Even under the more conservative deployment approved in this decision, the scale of SCE's covered conductor deployment will become the largest by far amongst the California IOUs,⁶⁷⁵ and it is entirely feasible that SCE will realize greater benefits and increased efficiencies through actual deployment, or the opposite may prove true. These factors would also impact the assumed cost-effectiveness and optimal level of deployment of covered conductor. Further, as SCE gains greater experience with covered conductor deployment, we agree with TURN that there may be opportunities for lower costs to be realized elsewhere (such as relaxing some of SCE's more stringent tree trimming where covered conductor is deployed while still adhering to GO 95 requirements). Therefore, as part of its next GRC filing, we direct SCE to further evaluate the interaction between its proposed wildfire mitigations, and whether costs can be reduced for ratepayers while still maintaining a consistent level of safety.

⁶⁷⁴ Ex. SCE-12, Vol. 1 at 5, Table II-1.

⁶⁷⁵ TURN OB at 111-112.

Regarding SCE's assertion that the operational realities of deploying covered conductor require additional circuit miles, since the Wildfire Risk Model is focused on evaluating risk at the circuit level, as opposed to operational design considerations, we find it reasonable to expect some additional operational miles to be installed during actual design and deployment. TURN maintains its proposed covered conductor budget is sufficient to capture not only the highest risk circuits but also the operational realities identified by SCE.⁶⁷⁶ It is not clear whether the additional operational miles would be inside or outside the HFRA, and we do not want to further reduce the risk reduction potential below the levels of risk identified in SCE's risk buydown curve. Therefore, we approve an additional 20 percent of circuit miles to account for operational design considerations, for a cumulative installation of 4,500 circuit miles of covered conductor over the 2019-2023 period.

In requesting the 20 percent adder, SCE broadly states that covered conductor circuits will benefit from increased PSPS event thresholds.⁶⁷⁷ As part of its next GRC application, we direct SCE to present a quantitative evaluation of how covered conductor has resulted in higher thresholds for initiating a PSPS event, broken down by Tier 2 and Tier 3 HFTDs, as well as an evaluation of how covered conductor has contributed to reductions in SCE's historic PSPS frequency, scope, or duration.

The scope of covered conductor circuit miles approved in this decision is consistent with the recommendations provided by Cal Advocates, while SCE's 2019 recorded data demonstrates that it has been able to significantly ramp up its

⁶⁷⁶ TURN RB at 35.

⁶⁷⁷ Ex. SCE-15, Vol. 5 at 28.

covered conductor deployment over a short period of time. Accordingly, we fully expect SCE to be able to execute the number of covered conductor circuit miles approved in this decision. However, to the extent SCE does not spend the full WCCP funds approved in this decision, any underspent funds will be returned to customers through the establishment of the two-way WCCP balancing account discussed in Section 17.13.

Regarding the appropriate ratio of fire-resistant pole wraps to composite poles, we do not find any party proposal to be particularly compelling. SCE does not explain how its decision tree logic better supports its proposed 60/40 split and has not actually run its population of poles through the decision tree, while TURN does not provide any basis for its proposed 75/25 split. We will adopt the lower cost 75/25 split, at an amount of \$144.614 million for the 2019-2023 period based on the adopted WCCP circuit mile forecast, but authorize SCE to create a two-way balancing account to track costs related to the actual replacement of poles under the WCCP (*See* Section 17.13).

Lastly, we approve SCE's 2019-2023 forecast of \$94.461 million to remediate approximately 3,200 tree attachments in in SCE's HFRA's. We agree with SCE that tree attachments present a unique wildfire risk given climate-change driven impacts to forested environments and the increased risk of trees becoming diseased or dying. Further, the amount requested appears modest to eliminate all risk associated with tree attachments in SCE's HFRA's.

With these adjustments, we authorize \$2.443 billion in combined 2019-2023 capital expenditures for the WCCP.

17.3. Fusing Mitigation

Fuses are safety devices consisting of a filament that melts if an electric current exceeds the fuses rating, thereby breaking the electric current. While SCE

has traditionally used conventional expulsion type fuses for Branch Line Fuse applications, over the GRC period SCE intends to utilize Current Limiting Fuses (CLFs) for most applications in HFRA. SCE states it selected CLFs because they can provide faster fault clearing for most faults, and a reduction in fault energy, compared to a conventional fuse. When faults do occur, de-energizing lines and limiting the amount of energy delivered to faults is expected to further minimize ignition risks and reduce collateral damage to upstream conductor and equipment.

SCE plans to install new fuses at 7,473 branch lines in HFRA that were not fused at the start of 2019, and replace all fuses at 1,254 locations where conventional fuses exist without compatible fuse holders. In addition, SCE intends to install 11 substation class electronically controlled fuses as a pilot in 2020, aimed at evaluating the expansion of fault energy reduction to main line circuitry and branch lines.⁶⁷⁸ The capital expenditure forecast for this activity is \$81.744 million over the 2019-2023 time period.⁶⁷⁹ SCE also forecasts \$1.089 million in O&M to replace fuses at 3,862 locations where conventional fuses exist with compatible fuse holders, and \$0.052 million to perform a pilot to evaluate Rapid Earth Fault Current Limiters, which are a group of technologies that can rapidly reduce fault current should a ground fault event occur.⁶⁸⁰ SCE's unopposed requests appear reasonable and are approved.

17.4. Retirement of Replaced Assets

As part of SCE's wildfire mitigation programs some capital assets will be prematurely retired, including poles and bare overhead conductor under the

⁶⁷⁸ Ex. SCE-04, Vol. 5A at 40-42.

⁶⁷⁹ Ex. SCE-15, Vol. 5 at 6.

⁶⁸⁰ *Id.* at 44.

WCCP as well as recently installed fuses (both discussed above). TURN recommends the Commission protect ratepayers from “paying for two pieces of equipment even though only one is installed.”⁶⁸¹ Specifically, in instances where SCE replaces, through the course of these programs, an asset that is less than five years old, TURN recommends either removing the remaining net recorded plant amount for that asset from rate base, or that associated return be set no higher than the cost of debt, preventing SCE from profiting from early retirement. TURN’s proposed five years is based on the idea that SCE should have been aware of the need for improved wildfire risk mitigation tactics during this timeframe. TURN further recommends these assets be tracked and reported annually.⁶⁸²

TURN’s recommendation is premised on the following issues: (1) the scale of SCE’s covered conductor proposal; (2) the observation that the replacement of conductor and poles is being driven by a new utility program, as opposed to factors not under SCE’s control; (3) the observations that SCE’s WCCP includes many lower risk circuits which, combined with a reliance on multiple other mitigations, undermines any argument that the replacement follows FERC guidance allowing utilities to replace assets in cases of inadequacy; and (4) arguments that there is precedent for removing assets from rate base, or adopting a reduced return on the remaining plant amount, where assets are removed from service before the end of their useful life.⁶⁸³

SCE asserts TURN’s position is unreasoned and goes against regulatory principles and precedence. Specifically, SCE asserts that: (1) its risk analysis

⁶⁸¹ Ex. TURN-02 at 26.

⁶⁸² *Id.* at 27.

⁶⁸³ TURN OB at 110-114.

demonstrates significant near-term risk of conductor failure that can potentially lead to ignitions, which is why these assets are being replaced; (2) the risk assessment related to wildfires changed suddenly and significantly for the entire state in 2017, and that SCE could not have predicted with perfect foresight the solutions and standards that would be necessary in the near future, nor refrained from installing and replacing infrastructure in the normal course of business;⁶⁸⁴ (3) some level of early retirement is already assumed in the average service lives authorized for SCE's assets, and that established asset life curves should only be disturbed if the life reduction is truly significant in costs and the replacement activity is tied to an imprudent act that uniformly results in that useful life reduction; and (4) related to SCE's Pole Loading Program (PLP), SCE asserts there is no evidence demonstrating any of the poles being replaced under PLP were not loaded accurately at the time installed, and that imposing an additional disallowance here would effectively constitute a "double penalty."⁶⁸⁵

It is uncontested in this proceeding that the poles, bare conductor, and fuses replaced as a result of SCE's wildfire mitigation program will be retired and no longer used and useful. TURN does not specify whether its proposal is intended to begin with new assets installed in 2021 TY, or at the beginning of SCE's WCCP; however, SCE's WCCP was first approved through D.20-04-013, addressing SCE's 2018 GSRP application, which included settlement language stating that "SCE will not be subject to disallowance or reduced authorized return associated with existing investment in recently replaced poles that are replaced in connection with GSRP activities."⁶⁸⁶ The GSRP settlement period

⁶⁸⁴ Ex. SCE-18, Vol. 2 at 9-11.

⁶⁸⁵ *Id.* at 11-13.

⁶⁸⁶ D.20-04-013 at 23.

extends through the end of 2020,⁶⁸⁷ and we see no reason to revisit the treatment of pre-2021 WCCP assets here.

Generally speaking, the Commission has determined that plant which is not used and useful should be excluded from rate base. However, the Commission has also made exceptions to this policy. In doing so, the Commission has stressed that the specific circumstances of each situation must be evaluated, including the burden and benefits of the plant assets in question.⁶⁸⁸

We will continue to grant rate of return treatment for assets retired under WCCP, as well as the fuse mitigation program, despite the fact that they are no longer used and useful. We make this determination based on the following evidence:

First, the Commission has found it appropriate to authorize a return on prematurely retired plant in instances where the retirement was due to Commission desires or actions.⁶⁸⁹ In this instance, the deployment of WCCP was first sanctioned by the Commission in D.20-04-013, and we continue to believe it plays an important role in reducing wildfire risk in SCE's territory in the immediate future. The benefits of grid hardening using covered conductor are supported by SCE's wildfire risk analysis, through the inclusion of (or lack of opposition to) some level of covered conductor deployment in intervenor proposals, and as evidenced by the WCCP funding approved in this decision. Similarly, we find good cause for replacing fuses in SCE's HFRAs to clear faults faster and minimize the number of customers impacted by an outage, and note that SCE's funding request for this activity is uncontested.

⁶⁸⁷ *Id.* at 38.

⁶⁸⁸ D.11-05-018 at 55.

⁶⁸⁹ *Id.* at 55-57.

Second, the level of deployment approved in this decision focuses on the riskiest circuits with the highest level of cost-effectiveness. As discussed above, SCE's risk analysis demonstrates these 3,750 circuit miles of bare conductor are inadequate to address near-term ignition risks, potentially leading to catastrophic wildfires. TURN also appears to take less of an issue with replacement of conductor on the riskiest circuits, stating "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."⁶⁹⁰

Finally, specific to TURN's recommendation to target assets installed within the last five years, given the significant wildfire-related policies, analyses, and fire maps developed over this timeframe, we do not believe SCE should be expected to have had perfect foresight regarding its final wildfire mitigation plans and the size and location of its HFRA, nor are we convinced it would be in ratepayers' best interest for SCE to have refrained from replacing relevant utility assets over such an extended timeframe and under the normal course of business, which could have presented its own safety concerns.

17.5. HFRA Sectionalizing Devices

SCE proposes to install new, and relocate existing, Remote-Controlled Automatic Reclosers (RARs) and Remote-Controlled Switches (RCSs) to poles just outside HFRA boundaries on HFRA circuits originating from substations outside the boundary. RARs are switching devices capable of interrupting fault current, operating in a similar fashion to substation circuit breakers. RCSs are a less robust sectionalizing device, not rated to interrupt fault current but capable of dropping load current. SCE states it intends to install RCSs, which are a lower

⁶⁹⁰ TURN OB at 113.

cost than RARs, at locations where the ability to interrupt faults is not needed due to a nearby upstream device already providing the desired protection. In remote locations where topography affects SCE's ability to maintain reliable radio coverage, SCE states it may elect to install manual pole switches. SCE also intends to employ Fast Curve Settings for RARs and circuit breakers, which it states will provide faster fault detection and interruption, and allow faults to be cleared more quickly. Together, SCE asserts these sectionalizing devices will: (1) allow SCE to further limit the number of customers impacted during PSPS events; (2) minimize the amount of circuitry, and thereby customers, sectionalized; (3) enable SCE to isolate many faults faster, thereby limiting total energy delivered to these faults and reducing ignition risks; and (4) permit SCE to remotely block reclosing of RARs and circuit breakers during elevated fire conditions.⁶⁹¹

SCE plans to install 122 RARs from 2019-2021, and 47 RCSs from 2019-2020. Including the unit costs for manual pole switches and the replacement of electromechanical relays, SCE's total capital expenditure forecast for the HFRA sectionalization program is \$50.972 million.⁶⁹² SCE's uncontested capital expenditure forecast is reasonable and is approved.

17.6. Distribution Fault Anticipation

Distribution Fault Anticipation (DFA) is a technology that utilizes devices with a predictive algorithm leveraging electrical system measurements to recognize current and voltage signatures indicative of potential incipient equipment failures. SCE asserts DFA can help minimize potential fire ignition

⁶⁹¹ Ex. SCE-04, Vol. 5A at 32-34.

⁶⁹² Ex. SCE-15, Vol. 5 at 6-7.

risks and increase circuit reliability by identifying the conditions that may lead to repeated and/or future fault events, improve SCE's ability to pinpoint the source of a fault, and allow for close monitoring of capacity banks.⁶⁹³ SCE is currently investigating the use of DFA to predict failures during its 2019-2020 pilot with Texas A&M Engineering and the Electric Power Research Institute, Inc. (EPRI).⁶⁹⁴ As of January 2020, SCE had installed 60 DFA devices at seven substations, and states it intends to continue to operate the 60 pilot installations through 2020 to determine how to best deploy targeted installations of DFA for 2021.⁶⁹⁵ SCE reports a cost of \$2.340 million to install the first 60 devices, and is requesting \$32.447 million to install an additional 750 DFA devices across HFRA circuits between 2021-2023.⁶⁹⁶ SCE also forecasts \$0.068 million for O&M, based on a negotiated contract with Texas A&M University to provide software/service, data interpretation, and integration services between 2019-2021.⁶⁹⁷

TURN recommends the Commission reject SCE's forecast for DFA from 2021-2023 and that SCE be directed to present the results of its DFA pilot before approving full roll out of the program.⁶⁹⁸ While TURN agrees DFA technology sounds promising, TURN argues the final results of SCE's pilot have not yet been analyzed by parties or the Commission. TURN further asserts SCE does not know whether the technology will work as expected, or whether "false positives" will cause SCE to deploy personnel to areas of the grid that are not failing, and

⁶⁹³ *Id.* at 37-38.

⁶⁹⁴ Ex. SCE-04, Vol. 5A at 46.

⁶⁹⁵ SCE OB at 136.

⁶⁹⁶ Ex. SCE-04, Vol. 5A at 48, Table II-17.

⁶⁹⁷ *Id.* at 49, Figure II-16.

⁶⁹⁸ TURN RB at 45.

that SCE has yet to demonstrate the technology is fully operational and that DFA can be scaled to the level of deployment requested in this GRC.⁶⁹⁹

In response, SCE points to the positive preliminary results that have been collected by Texas A&M using SCE's DFA devices in combination with 190 other units installed by other utilities during the January 2019 to May 2020 timeframe. Specific to SCE's 60 DFA installations, SCE indicates that two events were identified, one where a fault was created by Fault Induced Conductor Motion and another fault involving wind-blown conductors.

Regarding concerns that DFA will generate large amounts of data and produce false positives, SCE asserts a primary long-term benefit of DFA is to conserve resources through the automation of data capture and analysis,⁷⁰⁰ while SCE's experience with DFA, as well as others', has demonstrated there is not likely to be a significant number of false alarms. Finally, SCE states the DFA predictive algorithm is already operational and in use with the DFA installations on SCE's system.⁷⁰¹

Funding large-scale DFA deployment, prior to evaluating the full results from the DFA pilot, would obviate the general purpose of the pilot. Many of SCE's justifications for this activity rely on 'preliminary results', and we cannot accurately judge whether the costs and scale of this program are just and reasonable absent full review of the pilot study. Therefore, we do not approve any capital or O&M funding for further DFA deployment over the 2021-2023 GRC period. However, we also agree the initial findings from the DFA pilot are encouraging and, considering the length of time between GRCs, permit SCE to

⁶⁹⁹ Ex. TURN-02 at 8-10.

⁷⁰⁰ Ex. SCE-15, Vol. 5 at 41-43.

⁷⁰¹ SCE OB at 137-138.

include a request for this activity for 2024 along with the final pilot results in Track 4 of this proceeding.

17.7. Targeted Undergrounding

As part of its effort to reduce wildfire risk, SCE states it will conduct an assessment in 2019 to determine if certain overhead power lines should be converted to underground facilities. Undergrounding generally consists of digging a continuous trench, with vaults or manholes placed at regular intervals to accommodate cable pulling and electrical connections. Since SCE's Targeted Undergrounding Program is focused on reducing wildfire risk, SCE states that it will only be addressing energized electric conductors and will not be including any communications infrastructure. Although placing lines underground is typically less cost-effective at reducing risk than installing covered conductor, SCE states it may be appropriate to underground under certain circumstances where covered conductor would not sufficiently mitigate wildfire risk. SCE intends to underground six circuit miles in 2021, and 11 circuit miles per year in 2022-2023. Using a unit cost of \$3,370 thousand per mile for undergrounding based on 2018 Rule 20A undergrounding projects, SCE's capital forecast for the GRC period is \$108.642 million.⁷⁰² SCE's request is uncontested. We find reasonable and adopt SCE's forecast for targeted undergrounding.

17.8. Organizational Support

SCE requests funding for two areas of wildfire-related organizational support: Organizational Change Management (OCM) and Program Management Office (PMO).

⁷⁰² Ex. SCE-04, Vol. 5A at 49-52.

The OCM program focuses on managing the effect of necessary changes to business processes, systems and tools, job roles, policies and procedures, and other areas that may have a corresponding impact to resources. Related to SCE's wildfire mitigation efforts, SCE states the OCM program is needed to facilitate internal and external awareness, understanding, and knowledge of the many and varied changes resulting from increased grid hardening and resiliency of SCE's grid and the safety of SCE's employees, customers, and communities. SCE asserts this program is for new incremental change management functions, and includes efforts such as employee and other stakeholder communications, engagement, training, coaching, development, feedback, monitoring and advocacy. SCE's requested TY O&M for the OCM program is \$3.354 million.⁷⁰³

SCE's PMO program began in early 2018 with the following objectives:

- (1) executing near-term actions to further mitigate increased wildfire risk;
- (2) developing enhancements to SCE's operational plans for long-term wildfire, public safety, and related resiliency strategies; and (3) integrating SCE's wildfire mitigation strategies with existing programs, such as long-term capital planning, RAMP, and the GRC. SCE states that the PMO's core responsibilities have evolved over the course of the past year to provide oversight over all wildfire mitigation activities, and that SCE will augment current staff through vendor services to provide additional support as well as to provide analysis and expertise regarding program selection, sizing, and prioritization.⁷⁰⁴ SCE estimated the PMO support forecast by extrapolating existing vendor purchase orders for 2019 through 2020, assuming a linear decline from 2019-2021 until the

⁷⁰³ *Id.* at 52-53.

⁷⁰⁴ *Id.* at 53-55.

efforts can be managed by SCE labor. SCE's requested O&M expenses are \$22.655 million in 2019, \$12.271 million in 2020, and \$0 in 2021.⁷⁰⁵

Cal Advocates asserts SCE's OCM program is newly organized, but its proposed activities are not new. Cal Advocates explains SCE ratepayers have already provided funding for SCE's "changes to business processes, systems and tools, job roles, policies and procedures" and should not be required to pay twice for these normal, routine, and ongoing management activities.⁷⁰⁶ Further, Cal Advocates highlights that SCE's forecast does not consider previously authorized funding of these types of activities. To the extent SCE wants to reorganize, Cal Advocates argues SCE can redirect funding from other areas currently performing these organizational change activities to its newly establishing OCM program. For these reasons, Cal Advocates recommends SCE's full TY OCM request of \$3.354 million be denied.⁷⁰⁷

In response, SCE asserts wildfire management OCM work is not simply a reorganization or duplication of existing programs, and that the program is further complicated by the increase in work volume and complexities such as greater cross-organization coordination. Regarding Cal Advocates' assertion that ratepayers have already funded these types of activities, SCE asserts its forecast is bottoms-up, beginning with the OCM scope and then evaluating the incremental contract and SCE resources required to perform OCM work. SCE also asserts that reallocating funding from other areas that are currently performing organizational changes would disrupt SCE's existing business functions to the detriment of those operations. Finally, SCE states there is

⁷⁰⁵ *Id.* at 55, Figure II-19.

⁷⁰⁶ Cal Advocates OB at 147.

⁷⁰⁷ *Id.* at 147-148.

Commission precedent for supporting effective implementation of new programs and projects, including approval of OCM activities for SCE's Grid Modernization program in the 2018 GRC.⁷⁰⁸

We find SCE has provided reasonable justification for how its wildfire management OCM program is new and incremental to other OCM activities. Further, the types of activities included under the wildfire management OCM, such as training to perform wildfire mitigation activities and message delivery support relating to Public Safety Power Shutoff programs, appear to be justified based on their own merit. In considering the other OCM projects across the organization, each of the proposed activities appears to be discrete and unrelated, such that reallocating funding from any one of the other OCM areas would directly impact SCE's ability to perform those business functions. We also note all other OCM projects are unopposed by Cal Advocates. For all these reasons, SCE's requested TY O&M of \$3.354 million for the wildfire management OCM program is approved. SCE's uncontested TY O&M request for the PMO program is also reasonable and is approved.

17.9. Enhanced Operational Practices

SCE's enhanced operational practices consists of two activities: the Enhanced Overhead Inspections and Remediation Program, and the Infrared and Corona Inspection Program. Each of these activities is described below.

17.9.1. Enhanced Overhead Inspections and Remediation

In response to emerging climate and wildfire threats, SCE began its Enhanced Overhead Inspections (EOI) and Remediation Program in late 2018 as part of an effort to inspect all distribution and transmission assets in HFRA as

⁷⁰⁸ Ex. SCE 15, Vol. 5 at 46-49.

quickly as feasible, with the intent of finding asset conditions that could cause a spark or ignition. SCE states it inspects approximately half of its distribution assets in HFRA's each year and, beginning in 2020, started performing inspections based on the risk profiles of each asset.⁷⁰⁹

SCE asserts the EOI initiative builds upon SCE's desire to evolve beyond a compliance-based approach to a risk-based approach (while still achieving compliance requirements). Inspection results and analyses serve as the foundation for a risk-based inspection and maintenance strategy that SCE asserts will influence its inspection and maintenance programs moving forward, as well as the future design, construction, and operational standards/procedures to assess wildfire risks through the asset lifecycle.⁷¹⁰

17.9.1.1. EOI Capital

SCE's capital forecast for EOI is \$584.924 million over the 2019-2023 timeframe (including \$137.577 million over the 2021-2023 GRC period), based on previously completed capital notifications, bottoms-up methods, and capital IT project forecasts.⁷¹¹ With the exception of SCE's proposal for vertical switch replacement, the capital forecast for EOI is uncontested.

As part of the EOI program, SCE proposes to replace 190 vertical switches in its HFRA's for the 2021-2023 period, with a forecasted capital expense of \$5.294 million.⁷¹² The term "vertical switch" refers to a subset of gang operated overhead pole switches that are generally installed with vertical line construction. SCE asserts that vertical wood crossarms can twist, shrink, and

⁷⁰⁹ Ex. SCE-04, Vol. 5A at 55-56; *also*, Ex. SCE-15, Vol. 5 at 52.

⁷¹⁰ Ex. SCE-04, Vol. 5A at 56-27.

⁷¹¹ *Id.* at 59-60; Ex. SCE-04, Vol. 5AE at 6, and Ex. SCE-15, Vol. 5 at 6.

⁷¹² SCE OB at 148.

warp, impacting the switch bell crank system and potentially leading to performance issues. SCE proposes replacement of these switches with a composite crossarm design, which it argues will enhance grid reliability and reduce ignition risks caused by arcing and spark shower events.⁷¹³

TURN asserts SCE has not demonstrated that wholesale vertical switch replacement is justified by the associated safety improvement, and recommends the Commission reject SCE's forecast. Specifically, TURN observes SCE's testimony includes no information on the risk reduction potential of vertical switch replacement, and argues SCE has not presented any evidence to indicate that failure of a vertical switch has caused an ignition.⁷¹⁴ TURN also solicited input on the risk reduction potential of SCE's proposal from Mr. Dennis Stephens, a utility distribution engineer with Xcel Energy in Colorado for over 30 years.⁷¹⁵ According to Mr. Stephens, "there is no engineering basis for finding that replacement of vertical switches provides an ignition benefit."⁷¹⁶ Mr. Stephens testified during hearings that he has not often observed the problem that SCE's vertical switch program is designed to prevent,⁷¹⁷ and did not see other examples of the problem in materials supplied by SCE.⁷¹⁸

In response, SCE argues a fundamental flaw in TURN's opposition is that vertical switches present an ignition risk, even if SCE does not yet have record of a vertical switch being the source of a CPUC-reportable ignition. In 2019, SCE

⁷¹³ Ex. SCE-15, Vol. 5 at 49-50.

⁷¹⁴ TURN OB at 108-109.

⁷¹⁵ Ex. TURN-02 at 10.

⁷¹⁶ *Ibid.*

⁷¹⁷ RT, Vol. 11 at 1170:15-20.

⁷¹⁸ *Id.* at 1170:27-1171:3.

states 45 out of a population of 190 vertical switches in HFRA's presented ignition risk concerns due to their mounting hardware and alignment of the switch blade connections.⁷¹⁹ SCE highlights statements by Mr. Stephens indicating the dimensions of wooden crossarms can change and cause loose switch mountings, and that if such an issue could not be resolved through maintenance then the switch should be replaced. SCE further observed Mr. Stephens acknowledging that arcing and incandescent particles can result from misaligned switch contacts.⁷²⁰

SCE's justification for wholesale vertical switch replacement is unconvincing. Most of the evidence in this proceeding regarding the ignition risks from loose vertical switch mountings were presented by TURN's expert witness Mr. Stephens. While it is true that Mr. Stephens admitted it is technically possible for arcing and incandescent particles to result from misaligned switch contacts, SCE fails to address Mr. Stephen's more substantive points indicating that this event is unlikely,⁷²¹ and that proper maintenance can and should, in most circumstances, be used to fix the problem of loose vertical switch mountings.⁷²² Further, SCE's Enhanced Overhead Inspection Remediation program inspects assets in SCE's HFRA's with regularity, and includes remediation of potential issues as discovered (See discussion of this program below). SCE has not demonstrated why these more regular inspections and remediations are insufficient to address instances of vertical switch misalignment

⁷¹⁹ Ex. SCE-15, Vol. 5E2 at 52.

⁷²⁰ SCE OB at 148-149.

⁷²¹ RT, Vol. 11 at 1162:10-12.

⁷²² *Id.* at 1165: 11-19.

as conditions are observed. Therefore, we deny SCE's capital expenditure request of \$5.294 million for vertical switch replacement.

The remainder of SCE's 2019-2023 EOI capital expenditure forecast (\$579.630 million) is uncontested. We find reasonable and approve SCE's capital forecast for all other EOI activities.

17.9.1.2. EOI O&M

SCE's 2021 TY O&M forecast for EOI is \$54.232 million.⁷²³ SCE's forecast includes five subcomponents: EOI Distribution Inspections; Aerial Distribution Inspections; EOI Distribution Repairs; EOI Transmission Repairs; and EOI PMO Support (largely composed of IT activities to support EOI Implementation).⁷²⁴ SCE uses several different methods to calculate the forecast of each O&M sub-activity including, but not limited to, a bottoms-up method, historical and proposed inspections, and historical and proposed notifications/repairs.⁷²⁵

Cal Advocates proposes TY O&M funding of \$14.225 million, a \$40.007 million reduction from (*i.e.*, 74 percent of) SCE's request. Cal Advocates' forecast is premised on three elements: (1) using 2018 recorded adjusted costs; (2) authorizing partial funding for Aerial Inspections and EOI PMO; and (3) authorizing no funding for inspections or repairs on the distribution or transmission system.

Cal Advocates groups Aerial Inspections and EOI PMO activities together and normalizes the forecast for each activity over the three-year rate case cycle to "account for similar activities that have costs included in rates and to provide

⁷²³ Ex. SCE-04, Vol. 5AE at 57, Figure II-20.

⁷²⁴ Ex. SCE-15, Vol. 5 at 53-54.

⁷²⁵ *Id.* at 59, Figure II-21.

funding for additional TY activities.”⁷²⁶ Cal Advocates argues the Aerial Inspections lack supporting detail and that there is no historical data to review and analyze. Similarly, Cal Advocates points to a lack of detail to support individual line items for SCE’s EOI PMO IT forecasts; that existing rates include costs incurred for IT projects that have been completed, closed, or eliminated; and that those costs are available to fund efforts in the 2021 GRC cycle.⁷²⁷

Cal Advocates also recommends no TY funding for Transmission EOI repairs, Distribution EOI inspections, and Distribution EOI repairs. Cal Advocates accepts SCE’s alternative proposal for allocating additional funding for Distribution Inspections in the event SCE’s EOI proposals are rejected, which would effectively remove all funding from Distribution EOI Inspections and increase the Distribution Overhead Detailed Inspections from \$4.945 million to \$6.551 million.⁷²⁸ Cal Advocates observes “SCE’s historical expenses (2014-2018) for its Distribution Preventive and Breakdown O&M maintenance and its Distribution Overhead Detailed Inspections organizations have costs embedded in rates for performing the same inspection and maintenance activities as proposed by SCE’s newly organized Wildfire Management program,” and that both groups recorded expenses in 2018 incurred for performing EOI.⁷²⁹ Cal Advocates also objects to SCE’s requested funding for EOI repairs, both distribution and transmission, based on arguments that SCE does not adequately

⁷²⁶ Ex. PAO-06 at 63.

⁷²⁷ *Ibid.*

⁷²⁸ *Id.* at 64.

⁷²⁹ *Id.* at 64-65.

justify its forecast at the requested expense level, or account for historical expenses included in rates for the same proposed activities.⁷³⁰

In response, SCE asserts none of the components requested in the EOI program were authorized in the 2018 GRC, and that the activities being implemented are in addition to SCE's routine maintenance and inspection (M&I) work. Further, SCE asserts it removed historical costs for routine M&I activities in HFRAAs to ensure there is no double counting. Because EOI is different from traditional M&I programs, and since 2018 recorded costs only include one month of EOI ground activities and no costs for aerial inspections, SCE believes Cal Advocates' recommendation to use 2018 as the basis for the TY forecast is inherently flawed.⁷³¹ SCE also observes that Cal Advocates' use of the term 'normalization' is to divide SCE's TY forecast by three.⁷³²

Regarding the Distribution Aerial Inspection program, SCE asserts its forecast is well substantiated, based on the costs associated with data capture, processing, and labor costs for a Qualified Electrical Worker Review Team.⁷³³ Similarly, SCE asserts it has provided sufficient detail and justification to support its EOI PMO forecast. SCE states it is unclear what Cal Advocates is referring to in asserting that SCE's rates include costs for completed IT projects, but SCE maintains that previous GRC requests for IT projects do not have any relation to the EOI IT request in this GRC. Further, SCE observes Cal Advocates' proposed

⁷³⁰ *Id.* at 64-67.

⁷³¹ Ex. SCE-15, Vol. 5 at 56-57.

⁷³² *Id.* at 63.

⁷³³ *Id.* at 62-63.

O&M reduction for EOI IT runs counter to its position of not opposing EOI capital expenditures.⁷³⁴

SCE also asserts EOI inspections are different than SCE's Traditional Overhead Detail Inspection (ODI) work: while ODI is a prescriptive interval-based regulatory compliance inspection program, SCE asserts that EOI is a risk-informed inspection and remediation program that targets different risks beyond those addressed in ODI.⁷³⁵

Finally, SCE asserts Transmission EOI Repairs are not the same as Transmission O&M Maintenance activities (which address notifications identified during regular compliance inspections); that there is no overlap in its forecasts across this GRC; and that Cal Advocates' recommendation of zero funding should be rejected. Similarly, SCE states Distribution EOI Repairs are distinct from Distribution Preventative and Breakdown O&M Maintenance, and that there is no duplication in funding requests. Lastly, SCE argues the volume and cadence of repairs is much higher under EOI than what could be funded through Cal Advocates' proposal.⁷³⁶

In approving SCE's 2020-2022 WMP, the Commission found that "this inspection effort [the EOI program] represents a strength of the WMP."⁷³⁷ We continue to believe SCE's risk-based EOI program is of value, and the faster paced inspection schedule necessary to address heightened wildfire risk in SCE's HFRAs. We also note that some of SCE's other requested wildfire mitigation expenditures in this GRC (such as vertical switch replacement) have been

⁷³⁴ *Id.* at 64-67.

⁷³⁵ *Id.* at 61-62.

⁷³⁶ *Id.* at 58-59 and 63-64.

⁷³⁷ *See* Resolution WSD-004 at 37.

reduced based, in part, on SCE's ability to quickly inspect and remediate potential issues discovered through the EOI program. Overall, and as explained below, we find SCE has provided sufficient justification to support its requested EOI O&M expenses for the 2021 TY.

SCE provides a clear description of the differences between distribution EOI inspections and traditional ODI inspections: EOI inspections are targeted towards reducing ignitions, are risk-based, cover SCE's entire HFRA boundary every two years, and include both aerial and ground inspections. In contrast, SCE's ODI inspections are focused on GO 95 infractions, occur every five years, and consist primarily of ground-based inspections performed throughout SCE's service territory.⁷³⁸ As a general matter, given the distinct focus of each program, we agree that the EOI initiative is intended to be implemented in addition to, and not in lieu of, SCE's regular compliance- and safety-based inspections.

We also believe SCE provides sufficient justification to explain how its EOI inspection and repair forecasts are incremental and avoid double-counting. SCE provides two separate forecasts for ODI and EOI distribution inspections: the first is based on routine compliance-based inspection work in non-HFRA only, while the second is based on overhead inspection work in HFRA only. Collectively, these two programs represent the totality of SCE's requested funding of distribution inspections, segmented by fire risk areas.⁷³⁹

Similarly, we find SCE has taken reasonable steps to avoid duplication between its transmission repair and distribution repair forecasts. SCE's EOI Transmission Inspection work ended in 2019, and the forecast \$6.647 million in

⁷³⁸ Ex. SCE-15, Vol. 5 at 61-62; also, Ex. SCE Tr.2-02, Vol. 2 at 9-10.

⁷³⁹ Ex. SCE-15, Vol. 5 at 60.

this GRC for Transmission EOI repairs is based on actual findings or notifications from those inspections (including both ground and aerial inspections). In contrast, SCE's Transmission O&M Maintenance program addresses findings or notifications resulting from regular ongoing compliance inspections.⁷⁴⁰

On the distribution side, SCE's EOI distribution repair forecast is based on notifications identified during EOI inspections, whereas its Distribution Preventative and Breakdown O&M Maintenance program is based on a four-year average of recorded costs across SCE's service territory. To account for work performed under the EOI program, SCE reduced its Distribution Preventative and Breakdown O&M Maintenance forecast by the percentage of work performed on the overhead system, (47 percent) and the percentage of circuit miles in HFRAs (25 percent).⁷⁴¹

We also find that SCE has adequately justified its forecasts for EOI distribution aerial inspections and PMO IT projects, and that the IT projects currently in rates are unrelated to SCE's current PMO IT request. As explained by SCE, EOI distribution aerial inspections provide 360-degree visuals of overhead infrastructure, and are intended to help detect issues that may not be easily visible from the ground. The forecast for this activity appears reasonable, and is largely based on the costs associated with data capture and processing as well as labor costs for a qualified electrical worker review team.⁷⁴² SCE also provides a description of each PMO IT project, including activities such as cloud services and data storage for remote sensing aerial inspections and ArcGIS remote licensing, along with a forecast amount for each project over the

⁷⁴⁰ *Id.* at 58-59.

⁷⁴¹ Ex. SCE-02, Vol. 1, Pt. 2 at 19.

⁷⁴² Ex. SCE-15, Vol. 5 at 63.

2019-2023 timeframe. We have reviewed the proposed activities and amounts under this activity and find the forecast reasonable. Further, based on SCE's description of other IT projects, we believe SCE's PMO IT request to be incremental.

For all of the above reasons, we find reasonable and approve SCE's TY O&M forecast of \$54.232 million for the EOI program.

17.9.2. Infrared and Corona Inspection Program

The Infrared Inspection Program uses infrared technology to detect temperature differences and heat signatures of overhead distribution circuits, which SCE asserts may be indicative of degradation and potential component/conductor failure. SCE states these biennial inspections are prioritized based on risk categorization, and the majority of inspections will be performed by truck (with a small percentage of the system being performed by hiking or scanning from a helicopter).

Additionally, SCE seeks to perform annual infrared and Corona scans of all overhead transmission facilities located in HFRA's. Specialized infrared and ultraviolet (Corona) light cameras can be used to capture ultraviolet energy generated by leaking high voltage current. SCE states that if the leakage is substantial enough it can result in an arc flash and potential ignition; that infrared and corona inspections add a layer of detection into potential failures not visually detectable; and that past inspections have demonstrated these scans are reliable predictors of future component failures.⁷⁴³

SCE intends to inspect 5,000 miles of distribution lines and 5,300 miles of transmission lines per year using infrared and Corona cameras installed on the

⁷⁴³ Ex. SCE-04, Vol. 5A at 60-61.

same helicopter (and performing both inspections at the same time). The combined forecasted TY O&M cost for these activities is \$3.797 million.⁷⁴⁴ We find reasonable and approve SCE's uncontested TY O&M forecast.

17.10. Public Safety Power Shutoff

Public Safety Power Shutoff (PSPS) refers to the intentional de-energization of electrical equipment due to the threat of existing or impending wildfire. In a series of recent Commission decisions (D.12-04-024, D.19-05-042, and D.20-05-051), the Commission adopted PSPS reporting requirements and guidelines to mitigate the impact on customers when a utility considers implementing a PSPS event.

The table below compares SCE's overall PSPS O&M forecast in the 2018 RAMP Report with the forecast in this GRC (2018 \$000). SCE states the significant cost variance is primarily driven by its increased projection of 30 PSPS events per year.⁷⁴⁵

RAMP Mitigation Name	Filing Name	2019	2020	2021
PSPS Protocol and Support Functions	RAMP	\$3,704	\$3,769	\$3,475
	GRC	\$26,583	\$27,079	\$31,292
	Variance	\$22,879	\$23,310	\$27,817

SCE also forecasts \$3.716 million in capital expense for the procurement and installation of transfer switches at Community Resource Centers.

⁷⁴⁴ *Id.* at 62, Figure II-22.

⁷⁴⁵ *Id.* at 65.

SCE's PSPS activities are divided into the following three programs: PPS Execution, PPS Customer Support, and the Community Resiliency Equipment Incentives Program. Each of these programs is described below.

17.10.1. PPS Execution

PPS Execution is comprised of the following sub-components: (1) PPS Incident Management Team (IMT); (2) Line Patrols; (3) Mobile Generator Deployment; (4) Community Outreach Vehicles; (5) Community Resource Centers; and (5) Advanced Unmanned Aerial Study.

SCE's PPS protocol is overseen by a specialized Task Force in the Incident Command Structure (ICS), which in turn is overseen by the PPS IMT. SCE states the PPS IMT is responsible for monitoring relevant information before recommending the de-energization of any of SCE's electric circuit(s); executing the PPS protocol; and executing mitigation measures, where appropriate. Once elevated fire conditions subside, the PPS IMT deploys line patrols to identify potential safety hazards prior to turning the electricity back on.⁷⁴⁶

In this GRC, SCE requests funding to design and outfit five cargo transit vans as Community Outreach Vehicles (COVs), with the required equipment and technology to enable SCE staff to transport water, snacks, portable charging devices, lights, and other amenities to community locations where trained SCE staff will be able to provide real-time information on PPS events. Based on past PPS events, SCE asserts five COVs will be able to support typical PPS activations where multiple counties are impacted.⁷⁴⁷

⁷⁴⁶ Ex. SCE-04, Vol. 5A at 66-67.

⁷⁴⁷ *Id.* at 68-69.

To compliment COVs, SCE proposes to partner with existing community facilities and retailers to host customers indoors through the creation of Community Resource Centers (CRCs). SCE intends to work with county and local governments, community-based organizations, retailers, and existing relationships to identify locations that are safe, comfortable, and easily accessible to communities. Staff at these locations are anticipated to provide services and help customers obtain resources, keep customers up to date on the outage, educate customers about SCE offerings, and encourage them to update their outage information. SCE states it will arrange security personnel to support potential conflict de-escalation. Both the COVs and CRSs would be activated by the PSPS IMT, considering the scale and expected duration of an outage.⁷⁴⁸

PSPS Execution also includes funding for an Advanced Unmanned Aerial Study. SCE states its Advanced Unmanned Aerial Systems (UAS) program is developing the capability to expedite patrolling of utility lines following a PSPS event or other extended outage, which is expected to restore power more quickly and safely to customers. Today, SCE's Aircraft Operations department currently owns and operates three Unmanned Aerial Vehicles (UAVs) for conducting a variety of operations (*e.g.*, pole sets, inspections, line patrols). Because FAA regulations generally require an Unmanned Aerial Vehicle (UAV) to be within the line of sight of the operator or pilot, UAVs are currently not used for circuit patrols prior to re-energization. However, SCE states it plans to contract with an approved UAS vendor with experience in Beyond Visual Line of Sight (BVLOS) flight to further explore these capacities, better understand how to navigate FAA regulations, and lay the foundation to establishing an internal BVLOS UAS

⁷⁴⁸ *Id.* at 69-71.

program. SCE asserts the ability to conduct circuit patrols via UAV operating BVLOS is expected to be a more expedient, efficient, and cost-effective means to inspect electrical assets, especially for large-scale outages.⁷⁴⁹

SCE's requested TY O&M expenses for PSPS Execution are depicted in the table below (2018 \$000).⁷⁵⁰ Forecasts for the advanced unmanned aerial system study are based on pricing information provided by a specialized UAV vendor assuming 30 activations per year; forecasts for the five COVs include vehicle acquisitions costs as well as funding for amenities and event staffing; cost projections for CRC's include center activation and setup costs, staffing, security, additional services and incidentals, as well as some generator rental and fuel costs (where backup is needed); forecasts for line patrols include average times to conduct patrols and the estimated number of 30 activations per year; forecasts for mobile generator deployment are based on the estimated number of generators required for each event multiplied by the vendor cost for rental of the unit; and PSPS IMT costs include supplemental pay (outside of normal business hours) for personnel activated to support PSPS execution.⁷⁵¹

⁷⁴⁹ *Id.* at 71-73.

⁷⁵⁰ *Id.* at 74, Figure II-23.

⁷⁵¹ *Id.* at 74-75.

Activity	Recorded 2018	Forecast 2021
Advance Unmanned Aerial Systems Study		\$101
Community Outreach Vehicles	\$169	\$342
Community Resource Centers		\$1,278
Line Patrols		\$10,196
Mobile Generator Deployment		\$1,724
PSPS Execution IMT		\$282
Totals	\$169	\$13,922

SCE also requests \$3.716 million in capital expenses for a transfer switch at each Community Resource Center requiring backup generation.⁷⁵²

No party opposed any of the proposed O&M expense or capital expenditures under the PSPS Execution Program. We find SCE's forecast for these activities to be reasonable, and appreciate that many of the mitigation activities will provide support and up-to-date information in ways that will be accessible to communities impacted by one or more PSPS event(s). SCE's uncontested funding request for PSPS Execution is approved.

While we do not have any basis to question SCE's assumed 30 PSPS events per year, the number is higher than what SCE included in its 2018 RAMP Report and appears to be at odds with SCE's statement that "a PSPS event represents the mitigation of last resort in a line of defenses against fire."⁷⁵³ The Commission has made clear the importance of reducing the impact of, and need for,

⁷⁵² Ex. SCE-15, Vol. 5 at 6-7.

⁷⁵³ Ex. SCE-04, Vol. 5A at 64.

de-energization events to mitigate wildfire risk,⁷⁵⁴ and has alerted SCE of the need to make quantitative commitments of expected reductions in PSPS frequency, scope, or duration.⁷⁵⁵ Given the importance of decreasing PSPS events over time, we direct SCE to address as part of its next GRC filing how it has leveraged the implementation of grid hardening and modeling tools approved through this decision to better assess thresholds for initiating a PSPS event, including a quantitative evaluation of how covered conductor has resulted in higher thresholds for initiating a PSPS event, broken down by Tier 2 and Tier 3 HFTDs, as well as an evaluation of how covered conductor has contributed to reductions in SCE's historic PSPS frequency, scope, or duration.

17.10.2. PSPS Customer Support

SCE states it is important to acknowledge that customers wish to receive and seek out information via a method of their choice, and that in today's information-rich world SCE faces fierce competition to capture a finite amount of consumers' attention. With these concepts in mind, SCE identifies the following subcomponents of its PSPS Customer Support program: (1) IOU Customer Engagement; (2) Annual Wildfire Customer Direct Mailer; (3) PSPS Website Improvements; (4) Customer Research and Education; (5) Community Meetings; (6) Emergency Outage Notification System; and (7) Customer Contact Support Center.

For customer engagement, SCE identifies the need to inform all residents, and those who may be visiting within SCE's service territory, about the PSPS program and how to prepare. SCE asserts it will coordinate with PG&E and

⁷⁵⁴ See D.20-05-051 at 72.

⁷⁵⁵ Resolution WSD-004 at 11.

SDG&E, the California Governor's Office of Emergency Services (CALOES), and California Department of Forestry and Fire Protection (Cal Fire) to ensure messages are consistent; that communication materials will be created in multiple languages; and that special emphasis will be placed on difficult to reach customers. SCE's plan relies upon an integrated mix of communication, which may include bill inserts, direct mail/email, social media posts, digital and social media ads, search engine marketing and radio ads.⁷⁵⁶

SCE began its annual wildfire customer direct mailer in 2018 with an intent to raise awareness about SCE's work to support wildfire mitigation efforts. Past mailers were sent to approximately 1.5 million customers in SCE's HFRA's. For 2019, SCE intends to send a wildfire mailer to all customers, using two versions tailored to those in HFRA's and those in non-HFRA's.⁷⁵⁷

SCE states it has created a dedicated, interactive, and informative webpage where customers can increase their awareness of PSPS, learn how to be more resilient during PSPS events, receive up to date information regarding events in their area, and navigate to SCE's Outage Map. SCE expects to continue to enhance its website as customer feedback is gathered.⁷⁵⁸

For customer research and education, SCE states its strategy will align with the Statewide Campaign, but that it will also conduct focus groups and customer surveys to further inform how and when SCE can best educate its customers.⁷⁵⁹

⁷⁵⁶ Ex. SCE-04, Vol. 5A at 77-78.

⁷⁵⁷ *Id.* at 78.

⁷⁵⁸ *Id.* at 78-79.

⁷⁵⁹ *Id.* at 79-80.

SCE identifies community meetings as an opportunity for residents in HFRAs to hear firsthand from appropriate SCE staff, and other community leaders or agencies, about SCE's wildfire mitigation measures (including PSPS), and provide customers an opportunity to update their contact information.⁷⁶⁰

Prior to a de-energization event, SCE utilizes its Emergency Outage Notification System to deliver outage communications in the customers' digital channel(s) of preference (smartphone, SMS text, email TTY and social media) regarding de-energization events. Communications are sent in the following order: local government and public safety agencies; critical care customers; essential service providers; and business and residential customers.⁷⁶¹

SCE's Customer Contact Center and outsource partner (GCS) handles approximately 17 million inbound customer calls a year, and is available at all times year-round. SCE asserts its energy advisors will need to be trained and prepared to respond to all customer inquiries regarding SCE's wildfire mitigation activities, particularly as it relates to PSPS events. SCE's resource availability and staffing needs during PSPS events were estimated using historical service and staffing level during storm situations taking into account call patterns observed during past Summer Discount Plan events. For PSPS, SCE assumed a large portion of calls from customers within the first hour, with inquiries for status updates every eight hours thereafter. Using these forecasts, SCE projects normal scheduled work times for resources as well as the need for overtime at a forecasted average of approximately nineteen full-time resources per event.⁷⁶²

⁷⁶⁰ *Id.* 80-81.

⁷⁶¹ *Id.* at 81.

⁷⁶² *Id.* at 81-82.

SCE's TY O&M expenses for PSPS Customer Support functions are depicted in the table below (Constant \$000).⁷⁶³ SCE's forecast for IOU Customer Engagement is based on its cost of contribution to the statewide campaign; the forecast for Direct Mailings is based on the average per unit cost of SCE's historic mailings; website improvement costs are based on a vendor quote; the forecast for Customer Research and Education is based on estimated costs by different media intended to be used; the forecast for Community Meetings is based on an average of 18 town hall meetings per year, using recorded costs from the Community Meetings conducted in 2018; the forecast for Emergency Outage Notification System is based on a vendor quote; and Customer Contact Support Costs are based on average handling time with similar calls from 2016 and 2017, with hold time translated into labor costs and an assumed 30 activations per year.⁷⁶⁴

⁷⁶³ *Id.* at 82, Figure II-25.

⁷⁶⁴ *Id.* at 82-83.

Activity	Recorded 2018	Forecast 2021
Customer Contact Center Support	\$3	\$2,997
Customer Research and Education		\$759
Direct Customer Mailings	\$27	\$3,604
Emergency Outage Notification System	\$607	\$847
IOU Customer Engagement	\$215	\$5,000
PSPS Website Improvements		-
Town Hall Community Meetings		\$105
Totals	\$852	\$13,311

We find reasonable and approve SCE's uncontested forecast for PSPS Customer Support.

17.10.3. Community Resiliency Equipment Incentive Program

The Community Resiliency Equipment Incentive Program (CREIP) would allow customers with behind-the-meter distributed generation (DG) and energy storage to obtain an incentive for a portion of qualifying costs that would enable the customer to island its DG and energy storage system during a power outage. SCE states most non-residential customers with distribution generation and energy storage are only capable of self-generation in a grid-tied configuration; when the electric grid goes down, these customer resources do not provide power to the customer's premise. SCE asserts the CREIP would target customers supplying critical services to the community (*i.e.*, police, fire, water, telecommunications, emergency operations, medical services) and customers designated as a Community Resource Center (open to the community during a

PSPS event), and rebates would cover a portion of the qualifying system costs associated with microgrid controls, transfer switches, and other equipment necessary to enable islanded operation. SCE also intends to make funding available for low-income, critical care customers with on-site backup generation using a battery backup system who have at least one piece of critical medical equipment.⁷⁶⁵ Customer rebates would be available on a first-come first-serve basis as described in the following table:⁷⁶⁶

Customer Segment	Potential Rebate Available	Maximum Rebate Per Customer	Minimum Annual Allocation of Funding
Community Resource Center	\$0.15/Wh	\$100,000	25%
Critical Services	\$0.10/Wh	\$25,000	25%
Low Income Critical Care	\$500	\$500	10%

In light of the Assigned Commissioner's Ruling issued in R.12-11-005, seeking comments around a resiliency adder through SB 700, SCE states it may modify the Community Resiliency Program in the future. Once the program has been established, SCE intends to use a Tier 2 Advice Letter for changes to the program requirements, design, process, and budget. The expenses forecast for this program consist of \$3.259 million in available rebates and \$0.191 million to support two full-time employees for program administration.⁷⁶⁷

Cal Advocates proposes TY funding of \$1.150 million, a reduction of \$2.3 million from SCE's request. Cal Advocates' methodology was to divide

⁷⁶⁵ *Id.* at 83-85.

⁷⁶⁶ *Id.* at 85, Table II-23.

⁷⁶⁷ *Id.* at 88.

SCE's TY forecast by three to account for similar activities provided by the Self-Generation Incentive Program (SGIP), which already has costs included in rates. Cal Advocates asserts SCE has not adequately justified its forecast at the requested expense level, or provided a comparison, evaluation or analysis to existing SGIP costs; that SCE has not acknowledged its shareholders receive benefits when SCE customers with behind-the-meter generation and storage supply power during an outage (by not receiving negative press associated with outages, and the possibility that shareholders could be responsible for payments and/or refunds for outages); and that TY funding of \$1.15 million is sufficient to continue to close the gap for some customers who may decide to invest in an energy storage system with islanding capabilities.⁷⁶⁸

In response, SCE asserts that the purpose of SGIP is to encourage customers to install on-site generation and energy storage, whereas CREIP is intended target a specific set of customers that will promote resiliency in a way that benefits the community. SCE also asserts the additional Equity Resiliency Incentive payment available under SGIP is unlikely to cover the cost of a microgrid controller necessary for islanding, especially for the larger facilities that SCE is targeting under CREIP. SCE observes that Cal Advocates does not address the low-income, critical care rebate in its proposed reduction.

Because CREIP cannot begin until the Commission has adopted it, SCE states there are no historical costs available for review; however, this has not prevented the adoption of new programs in the past. SCE also asserts Cal Advocates' claim that shareholders would benefit from the CREIP are entirely unsubstantiated and unsupported by empirical evidence. According to

⁷⁶⁸ Ex. PAO-6 at 51-55.

SCE, taking Cal Advocates' observation to its logical conclusion would mean shareholders should fund the entire GRC revenue requirement since all requests are in same way tied to maintaining a safe and reliable grid.⁷⁶⁹

The Commission supports the use and accelerated deployment of microgrids and resiliency projects to minimize the impacts of wildfire power outages and PSPS events. In D.21-01-018, the Commission adopted rates, tariffs and rules to facilitate the commercialization of microgrids pursuant to SB 1339. D.21-01-018 also directs SCE, PG&E, and SDG&E to develop a Microgrid Incentive Program (MIP) to fund clean energy microgrids to support vulnerable populations impacted by a grid outage.⁷⁷⁰ While the two programs target similar types of customers and purposes (*i.e.*, those that provide critical services during an outage) the CREIP is intended to target behind-the-meter distributed generation and energy storage projects whereas MIP targets projects with longer duration and more complex multi-properties,⁷⁷¹ which are typically located in front of the meter. Given these distinctions, and since the MIP is expected to take time to develop, we see little risk of overlapping funding or program duplication.

However, we agree with Cal Advocates' more general point that SCE's proposal lacks specific details regarding how CREIP coincides with existing SGIP incentives. As noted by SCE, the Commission recently approved an Equity Resiliency budget carve out in SGIP to provide incentives for vulnerable customers and critical service facilities in HFTDs or those who have been affected by PSPS events. The Equity Resiliency incentive is set at \$1,000/kWh,

⁷⁶⁹ Ex. SCE-15, Vol. 5 at 71-74.

⁷⁷⁰ D.21-01-018 at 55-70.

⁷⁷¹ *Id.* at 66.

which was designed to “fully or nearly fully subsidize the installation of a storage system.”⁷⁷² SCE attempts to distinguish CREIP by explaining the program will target a specific set of customers expected to promote resiliency in a way that benefits the community; however, these appear to be the same types of customers already targeted under the SGIP Equity Resiliency budget.⁷⁷³ Further, one of the requirements prior to customers receiving an Equity Resiliency incentive is that associated behind-the-meter storage systems are able to operate in island mode.⁷⁷⁴ SCE does not provide sufficient justification demonstrating why the CRERIP is warranted given the existing focus and incentives provided through SGIP, nor does it fully explain why the proposed rebate is needed for “larger facilities that SCE is targeting under CREIP.”⁷⁷⁵

Given the potential duplication with existing SGIP incentives, we decline to approve funding for SCE’s CREIP proposal, but do not prohibit SCE from requesting funding for this program in the future provided the above issues are sufficiently addressed in SCE’s request.

17.11. Enhanced Situational Awareness

SCE’s Situational Awareness Center (SA Center) houses five meteorologists who provide forecasts, analytics, and hazard advisories to support the execution of core business functions. The SA Center is equipped with high resolution and fire modeling capabilities which SCE asserts increase its capacity to forecast elevated weather conditions and potential wildfire activity.

⁷⁷² D.19-09-027 at 36.

⁷⁷³ *Id.* at 24-25.

⁷⁷⁴ *Id.* at 43.

⁷⁷⁵ Ex. SCE-15, Vol. 5 at 72.

SCE's request in this GRC is for additional equipment to build out capabilities in the SA Center, including the deployment of new weather stations and high-definition cameras. Weather stations are equipment containing sensors that capture and transmit weather data, including wind speed, humidity, etc. SCE's pre-existing weather stations were installed over twenty years ago and, while still in use, they lack the precision and capabilities of modern technologies. In addition, SCE's legacy weather stations were not deployed near circuitry in HFRA's, and SCE contends do not directly support its objective to forecast high fire conditions that may warrant de-energization. As of the end of 2018, SCE had installed 125 weather stations in HFRA's, and SCE plans to install an additional 725 weather stations from 2019-2020.⁷⁷⁶

SCE states it has partnered with the University of California, San Diego and the University of Nevada, Reno to procure, install, and maintain pan-tilt-zoom High Definition (HD) cameras at up to 80 locations. The HD cameras provide 911 confirmation for fires from up to a 100-mile radius, which SCE explains will help fire agencies determine the size and approximate location of the fire. SCE indicates it is working with local and state fire agency personnel to support the HD camera deployment and is targeting to provide up to 90 percent coverage of CPUC Tier 2 and Tier 3 HFTD areas.⁷⁷⁷

SCE requests a combined \$9.411 million in capital expenditures to purchase and install the 725 weather stations and 80 HD cameras, and \$3.594 million in O&M expense in the 2021 TY to analyze and use the data

⁷⁷⁶ Ex. SCE-04, Vol. 5A at 88-89.

⁷⁷⁷ *Id.* at 90.

provided by the weather stations and cameras, and for various expenses associated with maintaining, repairing, and replacing the equipment.⁷⁷⁸

Cal Advocates proposes a TY expense forecast of \$3.060 million, a \$0.534 million reduction from SCE's request. Cal Advocates argues SCE does not demonstrate that it incorporated into its TY estimates funding already included in rates for similar on-going and routine situational awareness activities. Further, Cal Advocates asserts SCE did not reallocate associated embedded funding when SCE reorganized, consolidated, and transferred staff to its established Enhanced Situational Awareness Program.⁷⁷⁹

In response, SCE argues its request for the Enhanced Situational Awareness program is incremental to previous activities; that the costs attributed to operational and emergency management staff are included in a separate volume and are not part of this request; and that detailed workpapers, including a bottoms-up staffing model, support its request for Enhanced Situational Awareness, none of which was specifically challenged by Cal Advocates. Finally, SCE asserts Cal Advocates' proposed O&M reduction is inconsistent with its proposal to fund all capital expenditures for this program.⁷⁸⁰

We find SCE provides sufficient justification for why the costs and personnel within SCE's Emergency Management organization are distinct, and requested separately, from the Situational Center. Further, SCE provides a detailed and reasonable forecast to support its O&M request, including incremental repair and maintenance costs for the weather stations and HD cameras, and a bottoms-up staffing model for the SA Center. Lastly, we agree it

⁷⁷⁸ Ex. SCE-15, Vol. 5 at 75-76, Tables II-24 and II-25.

⁷⁷⁹ Ex. PAO-06 at 59-62.

⁷⁸⁰ Ex. SCE-15, Vol. 5 at 76-77.

would be inconsistent to fund the proposed capital expenditures for Enhanced Situational Awareness without also including funding for the various expenses to utilize the data and maintain the equipment. SCE's requested capital expenditure and O&M funding for the Enhanced Situational Awareness program are reasonable and are approved.

17.12. Fire Science and Advanced Modeling

Fire Science is a broad term that involves the gathering and integration of science and technology to help with wildfire mitigation across SCE's service territory. SCE states that its multifaceted approach, including the generation of high-resolution model data and increased situational awareness of wildfires, climate, fuels, and fire behavior, will help SCE make more proactive wildfire mitigation decisions in the near-term and inform longer-term mitigation strategies, standards, and practices.

SCE identifies the following activities under this program:⁷⁸¹

- Vegetation (fuels) Modeling: SCE intends to use a new vegetation (fuels) model to estimate the moisture content of living vegetation (in combination with the moisture content of dead vegetation which is already estimated), using random forest machine learning techniques to approximate the live fuel moisture values.
- Fuels Sampling Program: A sampling program to help assess fuel moisture in living vegetation where existing data gaps exist. SCE states the output from SCE's fuel sampling will be shared with the broader fire community.
- Remote Sensing Satellite: SCE is pursuing vendor or satellite services to provide hyperspectral imagery to be used for situational awareness and super computer model improvement. SCE states resulting imagery will provide an awareness of the health of vegetation across SCE's

⁷⁸¹ Ex. SCE-04, Vol. 5A at 95-100.

- entire service territory and assist with restoration efforts in areas affected by fires/natural events.
- Surface Canopy and Fuel Mapping: SCE states it intends to procure high resolution surface canopy and fuels mapping data, including recent land disturbances, to input into all fire spread modeling.
 - Advanced Modeling Computer Hardware: SCE has acquired two High Performance Computing Clusters (HPCC) for the purposes of modeling the atmosphere, vegetation conditions, and fires. SCE states the outputs from these HPCCs will allow SCE meteorologists to view atmospheric and fuel conditions in a high level of detail, aiding in the ability to determine where and when significant fire activity may occur. In addition, SCE states it intends to acquire a third HPCC for the purpose of climate modeling, which will allow for the generation of temperature and precipitation forecasts for the medium range period (5-10 years).
 - Fire Science Enhancements: SCE states it intends to make several enhancements to its Fire Science modeling applications and procedures, including improvements to the seasonal forecasts of Santa Ana winds, fuels modeling, PSPS wind thresholds, migration to higher resolution modeling output, using ensemble approach to modeling, calibrating the Fire Potential Index, and real-time validation of the Weather Research and Forecasting model.
 - Asset Risk Modeling: SCE identifies the need to perform Asset Risk Modeling, focused on creating composite risk scores based on asset characteristic, environmental, and operational data. SCE states this modeling will provide further guidance on ignition risks to prioritize asset maintenance, upgrades, and replacement work.
 - Operational Analytics: Operational Analytics is focused on using analytics to develop advanced fault detection. SCE proposes to develop and improve energized wire down detection algorithms using streaming data from meters, SCADA, remote fault indicators, and other sensors to

shorten the duration of Energized Down Conductor events.

SCE requests \$3.948 million for the TY O&M, and \$13.274 million in capital costs between 2019-2021 for Fire Science and Advance Modeling.⁷⁸² Capital costs primarily fall under Advanced Modeling Computer Hardware, Asset Risk Modeling, and Operational Analytics activities, while the O&M forecast was developed using vendor quotes and itemized forecasting for the sub-work activities.⁷⁸³

Cal Advocates accepts SCE's proposed capital expenditures for this program, but proposes a TY expense level of \$2.204 million, or a \$1.744 million reduction from SCE's request. Cal Advocates observes that SCE's request for incremental funding is 110.78 percent over 2018 expense levels and asserts SCE does not substantiate the significant increase. Cal Advocates also argues that SCE failed to incorporate similar historical costs in its TY calculations that are embedded in rates. Cal Advocates utilized SCE's 2019 recorded expenses as the basis for its TY estimate since this is a newly established program without historical costs (2014-2017).⁷⁸⁴

SCE asserts Fire Science and Advanced Modeling are new programs which rely on evolving and emerging technology, new scientific methods, research, and practices. While some of these activities were included in the GSRP Settlement,⁷⁸⁵ SCE asserts there was no Fire Science program in the past, and the methodologies SCE will be using rely on new science on new hardware, using

⁷⁸² Includes 2019 recorded capital expenditures. (*Id.* at 102; Ex. SCE-12, Vol. 1 Appendix A at A-4.)

⁷⁸³ Ex. SCE-04, Vol. 5A at 101, Figure II-29 and 102, Figure II-30; Ex. SCE-15, Vol. 5 at 6-7.

⁷⁸⁴ Ex. PAO-06 at 56-59.

⁷⁸⁵ Adopted by D.20-04-013.

newly collected data. Further, SCE asserts Cal Advocates' proposed TY reduction is at odds with its acceptance of SCE's proposed capital expenditures of the program, which if adopted would leave the hardware and tools being significantly underutilized.⁷⁸⁶

We find SCE provided sufficient justification demonstrating why the funding for the Fire Science program is incremental, including that the requested funding will be used to analyze new scientific data from new Advanced Modeling Computer Hardware. Further, SCE's forecast is modest and well-supported. We approve SCE's requested O&M and capital funding for the Fire Science and Advanced Modeling program.

17.13. Wildfire Risk-Mitigation Balancing Account

In this GRC SCE proposes to establish a new two-way balancing account, the Wildfire Risk-Mitigation Balancing Account (WRMBA), to record the difference between: (1) the revenue requirement related to recorded O&M expenses and capital expenditures for wildfire mitigation-related activities, whether or not those activities were specifically set forth in a WMP, but excluding vegetation management activities (which are subject to a separate request); and (2) the authorized revenue requirement associated with forecast O&M and capital expenditures adopted in this proceeding. SCE asserts the WRMBA would obviate any potential concerns related to implementation of new wildfire-mitigation technologies, scope feasibility of SCE's proposed expenditures, and other related issues underlying potential forecast uncertainties for wildfire-mitigation-related expenses.⁷⁸⁷

⁷⁸⁶ Ex. SCE-15, Vol. 5 at 79-80.

⁷⁸⁷ SCE OB at 293-294.

TURN's primary recommendation is to reject SCE's proposal for a new WRMBA, with SCE continuing to record its incremental costs in existing memorandum accounts. Alternatively, TURN recommends the establishment of a one-way balancing account to track spending up to the amount authorized by the Commission (with any spending below authorized amounts to be returned to customers), along with a companion memorandum account to track spending above the authorized amount.⁷⁸⁸ TURN asserts that (1) SCE's WRMBA proposal would shift cost recovery risks from the utility to ratepayers, eliminating any reasonableness review for above-authorized costs; (2) using a memorandum account for above-authorized costs is consistent with Pub. Util. Code § 8386.4, which permits a utility to record in a memorandum account "costs incurred for fire risk mitigation that are not otherwise covered in the [utility's] revenue requirements."; (3) there are important distinctions between SCE's proposal and the balancing accounts adopted in the Grid Safety & Resiliency Program settlement and the settlement in PG&E's TY 2020 GRC; and (4) the creation of a two-way balancing account without opportunities for reasonableness review would render nearly meaningless the Commission's adoption of a forecast in this proceeding.⁷⁸⁹

In response, SCE asserts that: (1) Pub. Util. Code § 8386.4 does not prohibit the establishment of a balancing account, but provides an alternative path for cost recovery; (2) statute prohibits SCE from shifting funds authorized for wildfire mitigation plan-related spending on non-wildfire-mitigation programs; (3) the vast majority of wildfire mitigation activities are reviewed and approved

⁷⁸⁸ TURN OB at 245-249.

⁷⁸⁹ *Id.* at 241-245 and 249-251.

in the WMP process; (4) a two-way balancing account is appropriate for new activities whose actual costs can differ from recorded data; (5) if required, the Commission should, at a minimum, authorize a balancing account with a soft cap of 120 percent of initial authorization levels;⁷⁹⁰ (6) it is not possible to simply continue the “status quo” for spending being recorded in memorandum accounts since two of the four Fire Mitigation Memorandum Accounts have prescribed December 31, 2020 termination dates; (7) unlike the PG&E GRC and GSRP settlements, there is no record evidence in this proceeding to be able to determine what unit cost thresholds should be; and (8) TURN’s alternative proposal is indistinguishable from SCE’s alternative proposal (*i.e.*, a two-way balancing account with amounts above a specified threshold subject to reasonableness review).⁷⁹¹

When a forecast is uncertain, use of a balancing or memorandum account can reduce risk for both customers and investors, ensuring that any undercollection is returned to ratepayers while providing an opportunity for the utility to recover prudently incurred expenses. Given the significant scope of the WCCP approved in this decision, the potential for SCE’s covered conductor unit costs to be higher or lower than forecast, and general uncertainty regarding the proposed split between fire-resistant wraps and composite poles, we agree that balancing account treatment is appropriate in this instance. Therefore, SCE is authorized to establish a two-way balancing account for the WCCP, along with the requirement that SCE file an application for reasonableness review of any recorded costs in excess of 110 percent of the WCCP capital expenditure amounts

⁷⁹⁰ SCE OB at 293-297.

⁷⁹¹ SCE RB at 151-161.

authorized in this decision. Should SCE file an application for after-the-fact reasonableness review, the Commission will take into consideration SCE's most current WMP and corresponding wildfire risk analysis, and SCE may request an expedited schedule to review its request pursuant to Rule 2.9. Any undercollection that is less than 110 percent of the amount authorized in this decision, as well as the refund of any overcollection, shall be filed via a Tier 2 advice letter. We find the establishment of a two-way balancing account and application review process will accomplish many of the same ratepayer protections as TURN's alternative balancing account plus memorandum account proposal. As a general matter, we also agree with SCE that Pub. Util. Code § 8386.4 does not strictly prohibit the establishment of a balancing account for wildfire mitigation activities, as evidenced by the Commission's recent approval of a Wildfire Mitigation Balancing Account in PG&E's GRC,⁷⁹² but merely provides another pathway for potential cost recovery.

Aside from the WCCP, we do not believe any of the other wildfire mitigation activities approved in this decision warrant inclusion in the WRMBA. The projected scope and costs of these activities are significantly less than that of SCE's WCCP, with underlying forecasts that are often based on more established historical or unit costs. Further, despite SCE's argument that it is not possible to continue the 'status quo' since two of its Fire Mitigation Memorandum Accounts are set to expire, SCE's Fire Risk Mitigation Memorandum Account, established pursuant to Pub. Util. Code § 8386.4, allows SCE to record any incremental fire-risk mitigation costs "not otherwise covered in the electrical corporation's

⁷⁹² We take note that TURN was a signatory to the Joint Motion for Approval of Settlement Agreement in A.18-12-009, which included the request for the establishment of a Wildfire Mitigation Balancing Account. (See D.20-12-005 at 11 and OP 7.)

revenue requirements,”⁷⁹³ while SCE’s Wildfire Mitigation Plan Memorandum Account allows SCE to track costs incurred to implement SCE’s approved WMP.⁷⁹⁴ Therefore, even without the creation of a new balancing account for these activities, SCE has every opportunity to seek reasonableness review for any recorded costs incurred in excess of the amounts approved in this decision.

As a final matter, one of SCE’s arguments for the establishment of the WCCP is that, because the WMP process provides a venue for review of the scope of SCE’s wildfire mitigation activities, the “cost of activities performed in compliance with the approved WMP should be considered *per se* reasonable and recoverable from ratepayers.”⁷⁹⁵ SCE’s argument is belied by two facts: first, our finding that SCE has failed to justify the full scope and pace of its conductor deployment in this proceeding is consistent with direction provided to SCE through the WMP process.⁷⁹⁶ Second, the Commission has made it abundantly clear that it does not consider cost recovery when reviewing a utility’s WMP; rather, the issue of whether WMP costs are just and reasonable is left to an electrical corporation’s GRC or application permitted by Pub. Util. Code § 8386.4(b)(2).⁷⁹⁷ Therefore, the Commission’s ratification of the Office of Energy Infrastructure Safety’s approval of specific activities included within a WMP does not indicate the costs of those activities are just and reasonable, nor does it

⁷⁹³ Pub. Util. Code § 8386.4(b)(1).

⁷⁹⁴ Pub. Util. Code § 8386.4 (a); also, D.19-05-038, OP 18.

⁷⁹⁵ SCE OB at 296.

⁷⁹⁶ See Resolution WSD-004 at 10; WSD’s May 4, 2021, Revision Notice for SCE’s 2021 WMP Update at 3; and Draft Resolution WSD-020 (as of 8/12/2021).

⁷⁹⁷ See D.19-05-036 at 22; also, Resolution WSD-002 at OP 2.

preclude the Commission from determining the appropriate costs for recovery based on the expected pace or scope of a utility's forecasted WMP activities.

18. T&D Other Costs and Other Operating Revenue

18.1. T&D Other Costs

T&D Other Costs consist of O&M expenses for miscellaneous T&D contract, operations, and maintenance costs, including:⁷⁹⁸

- Work Order Write-Offs: Expenses associated with cancelled projects and uncollected costs for billable work orders.
- T&D Line Rents: Expenses SCE incurs to rent property it does not own, but which is required for SCE's T&D system, as well as the rental of sites where SCE has placed telecommunications equipment.
- Underground Utility Locating Service: Costs for SCE to be a member of, and participate in, a regional notification center for calls related to locating underground facilities.
- Capital-Related Expense: Expenses incurred for work that must be done when capital additions or replacements are performed, but which do not qualify for capitalization in accordance with standard accounting guidelines.
- Interconnection, Added Facilities, and Special Contracts: Encompasses the activities of three organizations within SCE, tasked with: (1) managing customer requests and developing contracts for generation interconnection, large retail load, and load growth projects; (2) managing FERC- and CPUC- jurisdictional interconnection contracts; and (3) managing the payment of funds under CPUC Tariff Rules associated with line and service extension projects, as well as other requests, such as temporary electric services and relocation of electric facilities.

⁷⁹⁸ Ex. SCE-02, Vol. 7 at 5-28.

- Utility Joint Ownership Obligations: Expenses associated with contracts with other utilities, where SCE is a transmission participant and must pay a share of the costs.

SCE's forecasts for these activities are based on a combination of historic average or last year recorded expenses, the application of observed year-over-year line rent changes, and a ratio of capital-related expense to capital expenditures for the last year recorded.⁷⁹⁹

For capital-related expenses, SCE requests the historic capital-expense ratios of 0.67 percent and 1.06 percent be multiplied by the approved transmission and distribution capital expenditure forecasts in this decision, respectively.⁸⁰⁰ We find reasonable and approve SCE's uncontested T&D capital-expense ratios, which are to be applied to the T&D capital expense forecasts approved in this decision.

For the remainder of T&D Other Costs, SCE forecasts combined TY O&M expenses of \$55.724 million. We find reasonable and approve SCE's uncontested forecasts for these activities.

18.2. T&D Other Operating Revenue

SCE receives tariffed other operating revenue (OOR) from transactions not associated with the sale of electric energy which offsets the revenue requirement SCE would otherwise collect from general ratepayers. SCE's T&D OOR activities include: ownership charges, pole rentals, transmission and distribution services, generation radial tie-lines, tie-line facilities rental agreements, miscellaneous

⁷⁹⁹ *Id.* at 9, 13-14, 17, 21, and 25-26.

⁸⁰⁰ *Id.* at 21; SCE OB at 157-158.

revenue, added facilities/interconnection facilities, and Net Energy Metering (NEM).⁸⁰¹

SCE forecasts 2021 TY T&D OOR of \$145.610 million, based on a combination of historic average or last year recorded expenses; customer requests for new pole attachments, added facilities, or interconnection facilities; the number of post-inspections estimated in the 2018 GRC; existing contracts; and FERC-approved rates.⁸⁰²

Three parties contested SCE's initial OOR forecast: CCTA objected to SCE's proposal to tariff a pole attachment fee, arguing that in D.98-10-058 the Commission provided that the pole rental fee should be set through private negotiations between the utility pole owner and the pole attachers. In rebuttal testimony, SCE withdrew its pole attachment fee and subsequently entered into a Pole Rate Agreement with CCTA which was approved through Advice Letter 4252-E.⁸⁰³

EPUC contested the rate and forecast for SCE-Financed Added/Interconnection Facilities. This issue is addressed separately in Section 41.2 of this decision.

Lastly, Conterra contested SCE's forecast for pole rentals. SCE and Conterra subsequently entered into a proposed settlement agreement which would have resolved all disputed issues concerning pole rental OOR. However, as discussed in Section 52.3, we reject the proposed settlement agreement between SCE and Conterra. Further discussion concerning the OOR forecast for pole rentals, including parties' respective litigation positions prior to the

⁸⁰¹ Ex. SCE-02, Vol. 7 at 1 and 30.

⁸⁰² *Id.* at 29-47; Ex. SCE-13, Vol. 7E2 at 3, Table I-4.

⁸⁰³ *See* Ex. SCE-13, Vol. 7 at 17; SCE OB at 159.

September 10, 2020 motion for adoption of a settlement agreement, is provided below.

SCE's forecasts for all other T&D OOR activities, including ownership charges, transmission and distribution services, generation radial tie-lines, tie-line facilities rental agreements, miscellaneous revenue, Customer-Financed Added/Interconnection Facilities, and NEM, are uncontested. We find reasonable and approve SCE's combined TY OOR forecast of \$85.963 million for these activities.

18.2.1. Pole Rentals

Pole rental fees include revenue from five activities: (1) rental of space on SCE's poles for renters or licensees (Annual Attachment Rental Fee); (2) rental unauthorized attachment penalties; (3) application processing and engineering (P&E) fees for pole attachment requests; (4) post-attachment inspection fees; and (5) conduit rentals.

The OOR for each activity is forecast by multiplying projected quantities and the applicable tariff rate. Based on an agreement between SCE and CCTA that was approved via Advice Letter 4252-E, SCE proposes an Annual Attachment Rental Fee of \$20.04 for July 1, 2020 to June 30, 2021, and \$21.36 for July 1, 2021 through June 30, 2024.⁸⁰⁴ SCE also proposes to continue a \$500 penalty for unauthorized attachments, which it first implemented in 2015; \$186.78 per customer request for P&E fees; \$215.67 per post-attachment

⁸⁰⁴ SCE OB at 159.

inspection,⁸⁰⁵ and annual conduit rentals calculated as a five-year average of the rate per foot.⁸⁰⁶

In testimony, Conterra proposed revised P&E and post-attachment inspection fees of \$60.02 and \$52.38, respectively. Conterra's proposed fees remove certain "adders" associated with SCE labor, management overhead costs, and contractor inspection costs, based on arguments that these costs are already captured in SCE's Annual Attachment Rental fee.⁸⁰⁷ Conterra also applies a credit of \$100.00 to the P&E fee as a proxy for the amount Conterra pays to an outside contractor to complete the survey and engineering work as part of the pole attachment application.⁸⁰⁸

Conterra asserts that SCE's proposed P&E and post-attachment inspection fees contain numerous infirmities, including a general lack of transparency and double recovery of costs.⁸⁰⁹ Conterra also asserts that the combined 423 percent increase in the P&E and post-attachment inspection fees, as proposed by SCE, is unreasonable from a rate shock perspective, would create a high barrier to entry for new firms vis-à-vis incumbent carriers, and would produce an unfair competitive advantage for SCE's own affiliate broadband operations.⁸¹⁰

In reply, SCE states it has charged attachers a single non-recurring P&E fee of \$80 since 2003. While SCE acknowledges the proposed increase of \$106.78 to

⁸⁰⁵ Ex. SCE-13, Vol. 7E2 at 17. In opening testimony, SCE initially proposed a post-attachment inspection fee of \$232 per pole. (Ex. SCE-02, Vol. 7 at 33.)

⁸⁰⁶ *Id.* at 33-34.

⁸⁰⁷ Ex. Conterra-01C, Attachments 2 and 3.

⁸⁰⁸ Ex. Conterra-02 at 12.

⁸⁰⁹ Ex. Conterra-01 at 5, 8, and 24-29.

⁸¹⁰ *Id.* at 7.

the P&E fee is substantial, SCE asserts the update is long overdue and necessary to address inflation, process build-out, and other factors.⁸¹¹

Regarding the post-attachment inspection fee, SCE indicates the fee was developed following findings from a Commission-adopted settlement which determined that overloaded poles were a contributing factor in the 2007 Malibu Canyon fire, and that the costs of post-attachment inspections have historically been borne by ratepayers. While SCE's application proposed a continuation of the \$232 post-attachment fee adopted as part of SCE's 2018 GRC, in rebuttal testimony SCE revised the fee to \$215.67 to reflect more recent operations, staffing, and vendor costs.⁸¹²

SCE also asserts the P&E and post-attachment inspection fees reflect SCE's cost of service based on the actual costs SCE incurs. Further, SCE states the inspection of all attachments is supported by a sampling of inspections SCE conducted in 2019, which found a failure rate of 68 percent on inspections performed of third-party attachments.⁸¹³

Regarding Conterra's proposed removal of certain costs in the P&E and post-inspection fees, SCE asserts that: (1) contractor and SCE labor costs, and the related adders, are not part of the calculation of the Annual Attachment Rental Fee; (2) unlike the Annual Attachment Rental Fee, which covers SCE's ongoing cost of owning and maintaining poles, the P&E and post-inspection fees solely relate to the underlying work activities necessary to manage and administer pole attachment requests by third-parties; (3) SCE's engineering work included in the P&E fee is vital to the safe and proper execution of attachments; and (4) SCE's

⁸¹¹ Ex. SCE-13, Vol. 7 at 8.

⁸¹² *Id.* at 15; Ex. SCE-13, Vol. 7E2 at 17.

⁸¹³ Ex. SCE-13, Vol. 7 at 9-11.

staffing plan accurately reflects the functions required to manage the final inspection process for third-party attachments.⁸¹⁴

Lastly, SCE clarifies that Edison Carrier Solutions (ECS) is not an affiliate but a department of SCE that operates under the framework for Non-Tariffed Products and Services (NTP&S). Therefore, ECS is not an applicant to the third-party attachment program, and does not incur the P&E fee, post-attachment inspection fee, or annual rental fee.⁸¹⁵

Overall, we find SCE's proposed P&E and post-inspection fees to be reasonable, necessary, and reflective of SCE's actual cost of service. Since the P&E and post-inspection fees are for incremental work to manage and administer new pole attachment requests by third-parties, we find that these fees are not duplicative of the activities covered under SCE's Annual Attachment Rental Fee, which addresses SCE's ongoing cost of owning and maintaining its poles. As such, we do not find any basis to remove SCE-related labor costs for activities that appear both discrete and incremental. Further, in light of the 68 percent failure rate SCE observed when conducting inspections of third-party attachments, we agree with SCE that it is in the public interest for SCE to conduct independent engineering work to validate compliance with SCE standards and GO 95 requirements.

While the basis of SCE's proposed P&E and post-attachment inspection fees appears to be reasonable, we are sympathetic to Conterra's rate shock concerns. We note that the post-attachment inspection fee was first implemented in May 2018 and that SCE's current, revised fee is \$16.33 less than what was

⁸¹⁴ *Id.* at 9-16.

⁸¹⁵ *Id.* at 16.

approved in SCE's 2018 GRC. However, SCE can and should be more diligent in making incremental updates to its P&E fee. SCE states that the previous P&E fee of \$80 had been in place since 2003 and that an update was long overdue, but there is nothing that would have prevented SCE from updating this fee on a more regular, incremental basis to avoid or alleviate potential instances of rate shock. Because SCE's P&E rate of \$186.78 became effective on April 1, 2019, and since there is nothing in the record to indicate the number of pole attachment applications that were invoiced and paid during this time, it is difficult to implement a more gradual P&E fee increase while also being fair to third-party attachers that may have already paid the current P&E rate. Therefore, we approve the continuation of the existing P&E rate of \$186.78; however, in recognition that SCE could have implemented a more gradual pole rental fee increase we direct SCE to forgive, on a one-time basis, any late fees for outstanding invoices associated with pole attachment requests that were submitted on April 1, 2019 or later.

Additionally, while we deny the September 9, 2020 motion by SCE and Conterra for approval of a settlement agreement (see Section 52.3), we take note that one of the terms of the proposed settlement is that Conterra not be required to submit ongoing pole loading calculations with its requests for attachments. There is nothing in the record of this proceeding to indicate how waiving this requirement would impact safety or cost considerations, but the proposal appears consistent with the Commission's recognition that a utility's engineering studies should "avoid duplicative costly engineering analysis which could undermine the economic advantages of building a carrier's own facilities."⁸¹⁶

⁸¹⁶ D.98-10-058 at 50.

Therefore, as part of the next GRC filing we direct SCE to evaluate whether this or similar process improvements could be applied to third-party requests for pole attachments. For any proposed process improvement(s), SCE shall consider whether there would be associated safety implications or additional costs borne by ratepayers.

Based on the discussion above, we approve SCE's P&E fee of \$186.78 and a post-attachment inspection fee of \$215.67. In addition, we approve SCE's uncontested Annual Attachment Rental fee (as outlined in SCE's Advice Letter 4252-E), penalties for unauthorized rental attachments, and fees for conduit rentals. We also find reasonable and approve SCE's corresponding TY T&D OOR forecast for pole rentals of \$10.348 million.

Lastly, beyond clarifying that ECS is not an affiliate, SCE does not respond to Conterra's assertion that ECS has an unfair advantage to the detriment of broadband competition and the greater public good. Given that SCE competes with Conterra directly for education customers in the same area where it owns poles,⁸¹⁷ and ECS is not subject to the pole attachment fees approved in this decision,⁸¹⁸ we have concerns regarding how the exemptions afforded to ECS complies with Federal Communications Commission (FCC) requirements that a utility charge "just, reasonable, and *nondiscriminatory* rates for pole attachments."⁸¹⁹ As discussed in Section 41.1 (NTP&S), SCE did not propose any changes to its NTP&S offerings in direct testimony and, consistent with prior Commission decisions,⁸²⁰ the assigned ALJs' June 17, 2020 email ruling

⁸¹⁷ Ex. Conterra-01 at 11; Ex. Conterra-02 at 5-6.

⁸¹⁸ Ex. SCE-13, Vol. 7 at 16.

⁸¹⁹ Federal Communications Act, 47 U.S.C. § 224 (emphasis added).

⁸²⁰ See D.09-03-025 at 301-302; D.12-11-051 at 657; and D.18-09-009 at 5.

determined that broader policy issues concerning SCE's NTP&S offerings and investments are outside the scope of this GRC.⁸²¹ While we reaffirm that a rulemaking is the more appropriate venue to consider broader NTP&S and associated revenue-sharing issues, the more limited issue of whether SCE's proposed pole attachment fees comply with federal and state law appears well within the scope of this proceeding. Therefore, we direct SCE to include testimony with its next GRC application explaining how its pole attachment fees comply with the requirement that SCE charge just, reasonable, and nondiscriminatory rate for pole attachments when ECS is not subject to these fees but competes directly with other telecommunications providers.

19. Customer Interactions

19.1. Customer Interactions O&M

The Customer Interactions Business Planning Group includes the following BPEs: (1) Billing and Payments; (2) Communications, Education, and Outreach; (3) Customer Contacts; and (4) Customer Care Services.⁸²² While SCE initially anticipated changes to the cost forecast and schedule for the Customer Service Re-Platform (CSRP) project in this GRC,⁸²³ those changes did not occur,

⁸²¹ Assigned ALJs' E-mail Ruling Granting in Part, and Denying in Part, Southern California Edison Company's Motion to Strike Portions of Opening Testimony of The Utility Reform Network, dated July 17, 2020, at 3-4.

⁸²² SCE OB at 160.

⁸²³ The CSRP capitalized software project is designed to implement a new enterprise customer relationship and billing system that will perform core customer service support functions, such as generating customer bills, enabling customer account management, and providing customers access to SCE rates and programs. In D.19-05-020, the Commission found that the CSRP Project "is anticipated to be beneficial to customers," but also determined that cost recovery through memorandum account treatment was appropriate. (D.19-05-020 at 160.)

and as a result SCE chose to excise the review of CSRP-related costs from this GRC.⁸²⁴

SCE forecasts combined 2021 TY O&M Expenses of \$185.216 million for Customer Interactions.⁸²⁵ Cal Advocates and TURN propose reductions to SCE's forecasts in each of the Customer Interaction BPEs, totaling \$19.826 million and \$24.220 million in combined reductions, respectively.⁸²⁶

19.1.1. Billing and Payments

Billing and Payment activities include billing services, credit and payment services, postage expense, and uncollectible expenses. SCE is tasked with accurate and timely billing for approximately 5.1 million service accounts. The Billing and Payment operation validates and processes usage data, develops and presents customer bills, and processes bill exceptions. The primary regulatory policies impacting these activities are disconnection policies, Community Choice Aggregation (CCA), SCE's proposal to close its remaining 11 rural office locations, and State declared emergencies resulting in bill deferments. Other cost drivers include the volume and complexity of billing, credit and payment work activities, the volume and cost of postage, and bad debt experience.⁸²⁷

19.1.1.1. Billing Services

Billing Services encompasses the development, management, maintenance, and support for SCE's customer usage and billing processes. Customers rely on usage and billing information not only to pay their bill but to manage their

⁸²⁴ Ex. SCE-03, Vol. 3A at 2-3.

⁸²⁵ Ex. SCE-14C, Table I-2 at 2. This amount does not include SCE's Update Testimony for Postage Expenses and concession on the closure of 11 rural offices, which are discussed in Sections 51 and 19.1, respectively.

⁸²⁶ Ex. SCE-14, Table I-1 at 2.

⁸²⁷ Ex. SCE-03, Vol. 1A at 4-7.

energy usage and energy costs. The main activities for Billing Services include: (1) customer service initiation/termination; (2) billing and energy usage process oversight and support; (3) billing exception processing; (4) mailing operations for paper bill statements, letters, and checks; (5) digital labor used to automate routine, rule-based, high volume transactions; (6) project management support for implementing new billing and other operational projects (including rate changes, new rate schedules, new regulatory programs, etc.); and (7) policy adjustments to resolve customer billing and meter issues and disputes.⁸²⁸

SCE's 2021 TY forecast for Billing Services is \$37.435 million.⁸²⁹ The Billing Services forecast is based on 2018 recorded costs (\$32.602 million) plus the following adjustments: (1) \$1.878 million in additional labor needed to manage a projected increase in billing exceptions for bundled accounts;⁸³⁰ (2) \$0.184 million in additional non-labor vendor costs for processing a projected increase in NEM applications; (3) \$2.843 million in additional labor to manage increased billing exceptions for unbundled CCA accounts; (4) Policy Adjustment expenses of \$242,000 to resolve customer issues and disputes (typically related to meter or billing errors); and (5) \$314,000 in estimated cost savings resulting from SCE's proposed Analytics & Integrated Marketing (AIM) initiative.⁸³¹ The net impact of these adjustments is a \$4.833 million increase.

When SCE or a customer identifies a billing concern that needs to be investigated and potentially resolved, this type of work activity falls outside of

⁸²⁸ *Id.* at 9-14.

⁸²⁹ *Id.* at 19, Table II-5 and 23, Figure II-6.

⁸³⁰ Bundled customers receive both electricity delivery and electricity generation services from SCE, whereas unbundled customers receive electricity delivery services from SCE but generation services from another service provider (such as a CCA). (Ex. SCE-03, Vol. 1A at 54.)

⁸³¹ *Id.* at 18-23.

the normally highly automated SCE billing process and requires trained staff to resolve; this labor-intensive work is considered a billing exception. SCE observes that over the past two years the volume and complexity of billing exceptions have grown due to the increase in NEM billing, CCA enrollment, Program Enrollment, Account Maintenance activities, and Residential Time-of-Use (TOU) rate changes.⁸³²

SCE's forecast for increased labor expenses and vendor costs is based on exception data trends observed during 2017 and 2018. SCE also considers it reasonable to include Policy Adjustment expenses as known, predictable costs incurred as a normal part of conducting business.

Lastly, SCE proposes its AIM Initiative in this GRC to improve customer's digital engagement and satisfaction. SCE anticipates the AIM Initiative will increase electronic billing program participation, thereby reducing postage costs.⁸³³

19.1.1.1.1. Intervenors

Cal Advocates recommends a TY O&M forecast for Billing Services based on SCE's 2018 recorded costs (\$32.602 million) with no additional adjustments. Regarding SCE's proposed adjustment for billing exceptions, Cal Advocates observes that the year-to-year change in exceptions has been minimal, while the spike in 2018 should be excluded as an atypical year due to a one-time unexpected issue from SCE upgrading its Meter Data Management System (MDMS).⁸³⁴

⁸³² *Id.* at 11-13.

⁸³³ *Id.* at 18-22.

⁸³⁴ Ex. PAO-08 at 5-7.

Regarding billing exceptions for bundled customers, Cal Advocates asserts that SCE has not adequately supported its claim that bundled customer exceptions are increasing in complexity or identified new issues that would require an increase of 30 full time employees (FTEs) (*i.e.*, an 18 percent increase over 2018 levels). Further, Cal Advocates states the programs that SCE identifies are already part of SCE's billing exception landscape; that the number of FTEs responsible for processing exceptions has decreased from 2016-2018, despite 2018 having a higher volume of exceptions; and that there will be fewer exceptions to be processed manually as SCE increases IT automated exception processing.⁸³⁵

Cal Advocates also asserts SCE's 2021 projection of CCA billing exceptions should be based on the percentage of new CCA accounts added in any given year and not the cumulative number of CCA service accounts. In adjusting the number of exceptions to a percentage of new CCA accounts anticipated in 2021, Cal Advocates observes that the corrected 2021 amount is three to five times less than the number of CCA exceptions SCE processed in 2017 and 2018.⁸³⁶

Lastly, Cal Advocates recommends the Commission continue to disallow Policy Adjustment expenses, asserting that SCE has not presented convincing evidence as to why the Commission's determination in the 2018 GRC should be revised.⁸³⁷

TURN recommends a TY O&M forecast for Billing Services of \$30.967 million, a \$4.963 million reduction from SCE's request.⁸³⁸ TURN's recommendation is premised on the following points: first, consistent with

⁸³⁵ *Id.* at 7-10.

⁸³⁶ *Id.* at 11-13.

⁸³⁷ *Id.* at 14-15.

⁸³⁸ TURN OB at 115.

Cal Advocates' position, TURN recommends removal of the \$1.878 million in labor to manage bundled account billing exceptions, and the removal of \$2.843 million in labor to manage CCA account billing exceptions. TURN asserts the increase in 2018 billing exceptions was due to SCE's mismanagement of an MDMS system upgrade and not growth in NEM and CCA billing exceptions. TURN also highlights that SCE's billing FTE level was highest in 2016, with both 2017 and 2018 having fewer FTEs, and that SCE expects a 42 percent decrease in the number of customers on complex rates that will require manual billing in 2021.⁸³⁹

Second, TURN recommends removal of the \$0.242 million in Policy Adjustments. TURN highlights that the Commission did not authorize any funding for Policy Adjustments in SCE's 2018 GRC, finding that "SCE has not established that ratepayers should pay for its errors."⁸⁴⁰ TURN asserts that SCE once again fails to provide a justification explaining why customers should pay for SCE's errors.⁸⁴¹

19.1.1.1.2. SCE Response to Intervenors

In rebuttal, SCE explains that increases in electronic billing and self-service options have no effect on the number of billing exceptions, and that 2018-2019 recorded data demonstrates a growth trend. For 2018, SCE clarifies it had already excluded the MDMS spike when calculating the growth rate of Edison SmartConnect (ESC) meter usage exceptions; further, ESC meter usage exceptions continued to increase in 2019 due to higher CCA enrollment and customer NEM adoption, both of which rely on interval data that is more prone

⁸³⁹ Ex. TURN-06 at 5-7.

⁸⁴⁰ D.19-05-020 at 134.

⁸⁴¹ Ex. TURN-06 at 7-8.

to errors. Since billing exceptions for CCA customers occur for many reasons, and at any time while receiving utility service, SCE asserts it correctly calculated its forecast for CCA billing exceptions. Lastly, in recommending the Commission disallow SCE's Policy Adjustments forecast, SCE asserts that Cal Advocates and TURN ignore SCE's testimony in this proceeding demonstrating that SCE's Policy Adjustments forecast is appropriate, reasonable, and not speculative.⁸⁴²

19.1.1.1.3. Discussion

While it is reasonable for SCE to use a trend analysis to estimate billing exception volumes, based on the evidence before us we find 2018 to be an atypical year that skews the data (*e.g.*, a 35 percent growth in exceptions over 2017). SCE attempts to argue that SCE meter usage exceptions have increased due to higher CCA enrollment and NEM adoption, but this argument is at odds with 2015-2016 data where both NEM and CCA exceptions grew while ESC usage exceptions decreased during the same period.⁸⁴³ Comparing CCA and NEM growth⁸⁴⁴ to the number of billing exceptions over a longer timeframe (2014-2017)⁸⁴⁵ similarly fails to support SCE's position that ESC meter usage exceptions are largely driven by higher CCA enrollment and NEM adoption. The overall growth rate of billing exceptions between 2014 to 2017 was also ~1 percent,⁸⁴⁶ which is not indicative of a significant, long-term growth pattern.

⁸⁴² Ex. SCE-14 at 7-14.

⁸⁴³ Ex. TURN-06 Attachment 1, DR TURN-SCE-060, Question 4.

⁸⁴⁴ *Id.* Attachment 1, DR TURN-SCE-068, Question 3; Ex. PAO-08 at 13; SCE-14, Attachment A at A-9 through A-10.

⁸⁴⁵ Ex. SCE-14 at 9, Table II-6.

⁸⁴⁶ *Ibid.*

Further, we find SCE has not clearly demonstrated why the current level of FTEs is insufficient. SCE was able to address the 2018 spike in billing exceptions with significantly fewer staff (170 FTEs) than proposed for the 2021 TY. An evaluation of historical data also does not provide a clear baseline or rationale to support a higher level of FTEs: SCE's Billing FTE level was highest in 2016, which also had the lowest number of billing exceptions, while 2017 and 2018 had relatively fewer FTEs but a higher number of billing exceptions.⁸⁴⁷

Lastly, despite SCE's claim that Policy Adjustments are predictable costs incurred as a normal part of conducting business, SCE fails to address the main reason these expenses were disallowed in the 2018 GRC; mainly, that "SCE has not established that ratepayers should pay for its errors."⁸⁴⁸

For all these reasons, we authorize a TY O&M forecast for Billing Services of \$32.602 million based on 2018 recorded costs with no additional adjustments.

19.1.1.2. Postage Expense

Postage Expense consists of SCE's costs to send billing statements, notices, and correspondence to SCE customers. This cost is primarily driven by the volume, weight, and postage rate to send these items. In recent years, mailing costs have been lowered significantly by encouraging customers to convert to electronic billing. SCE states that as of December 2018 approximately 38 percent of mailings were sent electronically, and that it continues to explore options to further encourage customers to switch from paper to electronic bills. SCE also minimizes postage costs by using bulk mail discounts.⁸⁴⁹

⁸⁴⁷ *Ibid.*; Ex PAO-08 at 10, Table 8-7.

⁸⁴⁸ D.19-05-020 at 134.

⁸⁴⁹ Ex. SCE-03, Vol. 1A at 4 and 24.

SCE's 2021 TY O&M forecast for Postage Expense is based on 2018 recorded costs (\$16.142 million), plus the following adjustments: (1) an increase of \$316,000 to reflect anticipated customer growth; (2) a reduction of \$1.123 million to reflect customer adoption of electronic billing; (3) a reduction of \$1.780 million based on anticipated savings from the AIM Initiative; and (4) a decrease of \$148,000 for mailing operations vendor expense costs, which SCE has historically presented as part of a separate Postage Expense activity.

SCE's 2021 TY Postage Expense forecast is uncontested. We agree that SCE's forecast is reasonable in approach and well-supported. However, SCE's Postage Expense forecast includes projected savings (\$1.780 million) from the AIM Initiative, which we reject for the reasons provided in Section 19.1.2.1.3. Since funding for SCE's AIM Initiative is rejected, the associated postage savings must be removed as well. Removing SCE's projected savings from the AIM Initiative results in a total authorized 2021 TY Postage Expense of \$15.187 million.⁸⁵⁰

19.1.1.3. Credit and Payment Services

Credit and Payment Services work is divided into three main activities: (1) Credit Services, which functions to mitigate loss of revenue by acquiring adequate security for newly-established customers and higher-risk existing customers; (2) Collection Activities, which includes tracking, monitoring, and performing follow-up actions on delinquent active and closed accounts; and

⁸⁵⁰ Note: This amount does not reflect the postage adjustments included in SCE's Update Testimony (See Section 51). Including these adjustments results in an overall approved 2021 TY Postage Expense of \$15.436 million.

(3) Payment Services, which provides SCE customers with convenient, efficient, and cost-effective payment options.⁸⁵¹

SCE's 2021 TY forecast for Credit and Payment Services is based on 2018 recorded costs (\$13.346 million), plus increases of \$0.637 million in labor and \$0.041 million in non-labor.⁸⁵² The additional \$0.637 million in labor is comprised of a projected 4 percent increase in average handling time (AHT) and a 16 percent increase in processing volume of work. SCE states the increase in AHT is driven by changes in work channel volume, while the increase in work volume is driven by a change in forecast methodology using incoming work volume as compared to completed work volume.⁸⁵³ Non-labor vendor cost increases are driven by support for off-network payment locations and a customer locating process for inactive accounts.⁸⁵⁴ SCE's overall TY O&M forecast for Credit Payment and Services is \$13.835 million.⁸⁵⁵

In response to arguments by Cal Advocates, TURN, and NDC, SCE's current forecast includes a \$0.2 million reduction reflecting the closure of 11 Rural Offices, an \$8,000 reduction reflecting a corrected customer growth rate (*i.e.*, 0.65 percent) in SCE's work volume calculation, and a reduction of \$0.668 million to correct an error with regards to CheckFreePay Services in SCE's non-labor forecast.⁸⁵⁶

⁸⁵¹ Ex. SCE-03, Vol. 1A at 33-35.

⁸⁵² Ex. SCE-14 at 16.

⁸⁵³ *Id.* at 16-18.

⁸⁵⁴ Ex. SCE-03, Vol. 1AE at 42E-45E.

⁸⁵⁵ Does not include SCE's concession on the closure of 11 Rural Offices. (SCE OB at 165; Ex. SCE-52A2E2 at 2.)

⁸⁵⁶ Ex. SCE-14 at 18 and 20; Ex. PAO-08 at 14; Ex. TURN-06 at 10; and Ex. NDC-01 at 13-14.

19.1.1.3.1. Intervenors

With SCE's inclusion of the \$0.2 million reduction reflecting the recent closure of its Rural Offices, Cal Advocates finds SCE's forecast for this activity to be reasonable.⁸⁵⁷

TURN and NDC recommend the Commission reject the \$0.637 million labor portion of SCE's TY adjustment for increased work volume and increased AHT. Regarding SCE's forecasted 16 percent increase in work volume, TURN and NDC highlight that recorded labor costs for Billing and Payments have steadily decreased (by an annual average of 6.7 percent) between 2014-2018, while the mix of electronic payments has resulted in steady overall decreases in the average cost per payment during the same timeframe.⁸⁵⁸ TURN further asserts that SCE miscalculated work volume growth.⁸⁵⁹ NDC asserts SCE's new forecast methodology is not indicative of SCE's inability to handle the volume of work being tracked, and should serve as a baseline measurement that can be compared to future work volumes.⁸⁶⁰

Regarding SCE's forecasted 4 percent increase in AHT, NDC claims that SCE "provides no explanation for why this increase might occur."⁸⁶¹ Further, NDC takes issue with the level of vacation and sick leave assumed in SCE's calculation of FTE available work hours, which NDC asserts is excessive, based on inconsistent methodologies, and incongruent with labor force trends. Using its own average FTE calculations, NDC reaches the conclusion that only 55 FTEs

⁸⁵⁷ Cal Advocates OB at 151.

⁸⁵⁸ Ex. TURN-06 at 8-9; Ex. NDC-01 at 10-11.

⁸⁵⁹ Ex. TURN-06 at 8.

⁸⁶⁰ Ex. NDC-01 at 12-13.

⁸⁶¹ *Id.* at 12.

(6 fewer FTEs than SCE's 2018 recorded level) are necessary to meet SCE's labor requirement.⁸⁶² NDC also observes the economic impacts from COVID-19 will likely result in lower customer growth and staff work hour availability.⁸⁶³ TURN states that "SCE seems to have cherry-picked the analysis by increasing the mix for all the activities that require a longer AHT than the average, and decreasing the mix for the one activity that requires a shorter AHT."⁸⁶⁴

19.1.1.3.2. SCE Response to Intervenors

In response, SCE maintains that its labor expense forecast is reasonable based on the following assertions: (1) using incoming work volume, as compared to a completed work volume, provides a more accurate forecast of the Credit and Payment Service work needed to be performed; (2) TURN's claim that declining overall cost per payment for Payment Services is misguided and fundamentally flawed, since it does not include payment exception and other collection activity transaction volumes; (3) the forecast increase in AHT is based on expected changes in work channel volume, accounting for process automation savings and targeted improvements for the work channels with greater expected volume; (4) NDC's modification to the calculation of FTE available work hours ignores 2018 recorded sick and vacation time, and reduces training needs based on an incorrect comparison to the training requirements for physicians and lawyers; and (5) NDC's recommended supervisor to representative ratio is inappropriate as SCE's staffing levels prior to 2018 were inadequate.⁸⁶⁵

⁸⁶² *Id.* at 14-18. SCE currently has 61 FTEs in Credit Payment and Services and is requesting an additional 10 FTEs in TY 2021. (Ex. SCE-03, Vol. 1AE WP at 43E.)

⁸⁶³ Ex. NDC-01 at 14 and 16.

⁸⁶⁴ Ex. TURN-06 at 8.

⁸⁶⁵ Ex. SCE-14 at 16-20.

19.1.1.3.3. Discussion

SCE's current O&M forecast for Credit and Payment Services accepts several corrections recommended by intervenors, including: a \$0.2 million reduction reflecting the closure of 11 Rural Offices, an \$8,000 reduction reflecting a corrected customer growth rate, and a \$0.668 million reduction to SCE's non-labor forecast for Credit and Payment Services. We find all these adjustments/corrections to be reasonable.

The sole remaining contested issue concerns SCE's proposed TY labor adjustment of \$0.637 million, which consists of a 4 percent increase in AHT and a 16 percent increase in processing volume of work. Beyond a general statement that SCE anticipates work volume changes between work functions,⁸⁶⁶ SCE provides no actual evidence, or explanation of the underlying drivers, to support the 4 percent increase; we find that SCE has not met its burden of proof to support an increase in AHT.

Regarding SCE's proposed 16 percent increase in processing volume of work (which is driven by a change in forecast methodology, using incoming work volume instead of completed work volume), we find SCE's comparison between completed and incoming work to be a useful metric in evaluating the potential volume of work not being done; however, SCE's new forecast methodology is based on limited 2018 data, and it is unclear how well this forecast methodology will track with actual incoming work observed in subsequent years. Moreover, as observed by TURN and NDC, average labor costs for Credit and Payment Services have been declining from 2014 through 2018, largely as a result of increasing electronic payments (and associated

⁸⁶⁶ *Id.* Attachment A at A-17.

decreases in mail-in and in-person payments). Additionally, as noted by NDC, SCE underspent \$1.35 million collected for CAPS labor costs in 2018.⁸⁶⁷ While SCE criticizes TURN's average cost per payment calculation for failing to include payment exception and other collection activity,⁸⁶⁸ SCE fails to respond to TURN's and NDC's more substantive point that the average cost per payment has been declining over time. Putting aside the actual cost per payment calculation, it is clear from SCE's own testimony that customer adoption of electronic billing has, and continues to, steadily increase,⁸⁶⁹ while recorded labor costs for Credit and Payment Services have gradually declined between 2014 and 2018.⁸⁷⁰ Thus, SCE's argument that it requires additional FTEs to address a backlog of work is inconsistent with historical decreases in recorded labor and prior underspending of labor expenses, as well as general decreases in the average cost per payment.

Based on the above, we find that SCE has not sufficiently justified its proposed TY labor increase of \$0.637 million. Removing this adjustment from SCE's forecast results in an authorized TY O&M forecast of \$13.179 million for Credit and Payment Services.

19.1.1.4. Uncollectible Expenses

Uncollectible expenses reflect the amount of revenue SCE is unable to collect despite collection efforts. Uncollectible expenses for all revenue components of customer accounts are authorized based on the uncollectible expense factor, which is expressed as a percent of SCE's total revenue. SCE

⁸⁶⁷ NDC Opening Brief at 13-14.

⁸⁶⁸ See Ex. SCE-14 at 17-18.

⁸⁶⁹ Ex. SCE-03, Vol. 1A at 15.

⁸⁷⁰ *Id.* at 42, Figure II-11.

indicates it attempts to minimize uncollected expense by helping customers through payment arrangements while also complying with regulatory requirements for security deposits and disconnections.⁸⁷¹

SCE's uncollectible expenses factor forecast is based on the average of the five-year period from 2014-2018 (0.196 percent), plus a net decrease of 0.016 percent based on uncollectible expenses related to CCA charges and the new disconnection policies adopted in D.18-12-013, for a total Uncollectible Expenses TY factor of 0.180 percent.⁸⁷² SCE's uncollectible expense factor is uncontested.⁸⁷³

We find reasonable and approve SCE's uncollectible expense factor of 0.180 percent.

19.1.2. Communications, Education, and Outreach

The Communications, Education, and Outreach (CE&O) BPE supports SCE's efforts to bring awareness to both residential and business customers regarding clean energy and energy savings program opportunities, rate and account management options, and safety initiatives. Activities also entail responding to customer inquiries, resolving customer complaints, and improving customer experiences with SCE programs and services. The CE&O BPE is organized along three subgroups: (1) Customer Communications, Education,

⁸⁷¹ Ex. SCE-03, Vol. 1A at 5 and 47.

⁸⁷² *Id.* at 54-56.

⁸⁷³ While TURN initially contested SCE's Uncollectible Expense forecast, through the discovery process SCE identified an error in its analysis and updated its uncollectible expense forecast rate from 0.191 percent to 0.180 percent. (Ex. SCE-14E2 at 23.) TURN supports SCE's current, updated uncollectible rate of 0.180 percent. (TURN OB at 122-123.)

and Outreach, (2) Escalated Complaints and Outreach, and (3) External Communications.⁸⁷⁴

19.1.2.1. Customer Communications, Education, and Outreach

Customer CE&O work activities include: (1) education and awareness offerings delivered at the Energy Education Centers in Tulare and Irwindale; and (2) the planning, creation, and optimization of multi-channel communications campaigns to drive customer awareness and adoption of rates and pricing options, as well as other electric service offerings. SCE's Energy Education Centers provide customers the opportunity to view technology demonstrations and participate in events, classes, and workshops on a variety of energy topics, such as utility programs, energy efficiency, demand response, renewable generation, electric safety, and transportation electrification. Multi-Channel campaigns create awareness of, educate customers about, and encourage the adoption of SCE programs, rates, services, and self-service options through a variety of communication and engagement channels.⁸⁷⁵

SCE forecasts \$9.193 million in TY O&M for Customer CE&O. SCE's forecast is based on recorded 2018 expenses (\$3.761 million) plus the following adjustments: (1) a net increase of \$3.95 million for SCE's Analytics and Integrated Marketing (AIM) Initiative;⁸⁷⁶ (2) an increase of \$1.047 million to

⁸⁷⁴ Ex. SCE-03, Vol. 2 at 3-4.

⁸⁷⁵ *Id.* at 8-15.

⁸⁷⁶ Including an increase of \$5.2 million to implement the AIM Initiative and an estimated \$1.25 million in forecast savings as a result of AIM enabling marketing, outreach, and service through lower-cost channels. (SCE OB at 168.)

support greater awareness and education of Critical Peak Pricing (CPP)⁸⁷⁷ and Building Electrification; and (3) an additional \$0.435 million for four previously unfilled positions that SCE expects to fill in 2019.⁸⁷⁸

Through the AIM Initiative, SCE proposes to hire a vendor to build a new, data-driven digital marketing analytics capability that will improve customer digital engagement and satisfaction in addition to reducing costs through greater adoption of paperless billing and self-service options. SCE states the AIM data-enabled approach will allow it to personalize education and outreach efforts to drive energy consumption behavior, product/service adoption, and to shift customer interactions to lower-cost digital channels.⁸⁷⁹ AIM costs are divided into three categories: (1) Enhanced Data Analytics, (2) Communications to Update Contacts, and (3) Enrollment Communications. Between 2021-2023, SCE forecasts an additional \$5.2 million each year to implement the AIM Initiative, and a corresponding average annual savings of \$3.343 million.⁸⁸⁰

19.1.2.1.1. Intervenor

Cal Advocates recommends rejecting SCE's AIM proposal. Cal Advocates asserts that SCE is already among the top ten utilities with the highest volume of customers receiving electronic bills⁸⁸¹ and that it does not make sense to burden

⁸⁷⁷ The CPP rate offers a discount on summer electricity rates in exchange for higher prices during 12 "CPP event days" each year, typically called on the hottest summer days. (Ex. SCE-03, Vol. 2 at 24.)

⁸⁷⁸ Ex. SCE-03, Vol. 2 at 20-26.

⁸⁷⁹ *Id.* at 22-24.

⁸⁸⁰ Including an average annual savings of \$1.250 million for providing marketing/outreach through lower-cost channels, which SCE applies to the Customer CE&O forecast, and \$2.093 million in annual paperless billing savings, which SCE applies to the forecast for Postage Expense. (Ex. SCE-03, Vol. 2 at 23-24.)

⁸⁸¹ According to a 2019 JD Power Electric Utility Residential Customer Satisfaction Survey (2019 JD Power Study). (See Ex. PAO-08C at 18; Ex. SCE-03, Vol. 2 at 22, fn. 31; Ex. SCE-14 at 30-31.)

ratepayers with a significant expense to accelerate an already high electronic billing adoption rate.⁸⁸² Cal Advocates also asserts the purported objectives of the AIM Initiative do not justify the costs; that SCE currently conducts, and receives funding for, multiple campaigns each year to “inform customers about their options to receive their SCE bill electronically and drive adoption of SCE’s customer self-service channels;”⁸⁸³ and that since 2015 SCE has been authorized to automatically convert a customer’s bill format from paper to electronic when customers pay their bills electronically.⁸⁸⁴

Regarding AIM funding for Communications to Update Contacts, Cal Advocates states that SCE already receives funding to communicate with customers located in HFRAs; that incremental PSPS communication-related costs should be recorded in the Fire Risk Mitigation Memorandum Account; and that SCE’s GSRP Application (A.18-09-002) includes approximately \$10 million for PSPS Protocol Support Costs.⁸⁸⁵

TURN also recommends the Commission reject SCE’s AIM proposal. TURN asserts the AIM Initiative is not cost-effective; that SCE has not demonstrated how the effort would provide tangible benefits to ratepayers; that SCE does not identify any cost reductions for its existing analytics and marketing labor costs as a result of the AIM Initiative; and that now is not the time for

⁸⁸² Ex. PAO-08 at 17-18.

⁸⁸³ Ex. PAO-08WP, SCE’s revised response to data request PubAdv-074-DAO, Q. 2(a-d), at 26-29; Ex. PAO-08 at 18-22.

⁸⁸⁴ Ex. PAO-08 at 23.

⁸⁸⁵ *Id.* at 20-21; Cal Advocates OB at 166-167.

utilities to engage in unnecessary spending when customers are already struggling to afford their energy bills.⁸⁸⁶

In addition, TURN recommends rejecting SCE's proposed increase of \$1.047 million to support greater awareness and education of CPP and Building Electrification.⁸⁸⁷ TURN asserts it is not reasonable for SCE to spend more money educating approximately 28,000 CPP customers per year than SCE spent to educate the close to 280,000 business service accounts prior to those customers being defaulted to CPP in 2019. TURN states that SCE also does not explain why it cannot use existing authorized funds to educate customers about Building Electrification.⁸⁸⁸

NDC does not take a position on SCE's 2021 TY forecast amount but suggests improvements to SCE's minority community outreach efforts. Specifically, NDC recommends that SCE rely upon more up-to-date survey information to target non-English speaking communities in its service territory and use cost-effective means to reach out to smaller ethnic groups, such as through partnerships with Community-Based Organizations (CBOs). NDC also recommends SCE be required to explain in future GRC testimony how it determines which communities it will target with in-language outreach.

With regard to SCE's Energy Education Centers, NDC alleges there is a lack of transparency regarding the costs SCE incurs for each workshop conducted, making it difficult to determine whether past workshops have proven effective or are beneficial to the communities served. On that basis NDC recommends SCE track and provide in future testimony an itemized breakdown

⁸⁸⁶ Ex. TURN-06 at 11-13.

⁸⁸⁷ *Id.* at 13; TURN OB at 126.

⁸⁸⁸ Ex. TURN-06 at 13-14.

of expenditures incurred for seminars and workshops conducted. Lastly, NDC recommends SCE track and report participant demographics of the workshops and seminars by ethnicity or, at the very least, provide a future cost analysis of including the demographic information, which NDC asserts will provide better insight into the success of the workshops in educating underserved communities.⁸⁸⁹

19.1.2.1.2. SCE Response to Intervenors

In response to Cal Advocates and TURN, SCE asserts the benefits of the AIM Initiative justify the costs, particularly when considering the longer-term operational benefits stemming from the AIM investment. SCE observes that neither Cal Advocates nor TURN dispute the short-term cost savings of the AIM Initiative, which results in a new cost per customer that is significantly lower than the current Customer CE&O benchmarks for PG&E and SDG&E. In the longer-term, SCE states its financial analysis shows a positive benefit-to-cost ratio, an assumed six-year payback period, and an estimated \$13.1 million in savings to SCE customers between 2021-2030. In addition, SCE clarifies that over the longer-term it intends to transition AIM-related knowledge from vendor partners to SCE employees.⁸⁹⁰

Regarding Cal Advocates' claim that there is no need to adopt new measures to increase customer enrollment in paperless billing, SCE asserts that the results from the 2019 JD Power Study were skewed based on inflated self-reporting by customers; that the 2019 JD Power Study indicates SCE has the opportunity to improve customer savings by increasing paperless bill adoption;

⁸⁸⁹ Ex. NDC-01 at 21-28; NDC OB at 17.

⁸⁹⁰ Ex. SCE-14 at 28-30.

and that organic growth alone will not allow SCE to meet its paperless billing goal of 58 percent in 2023 (compared to 46 percent of customers enrolled at the end of 2019). SCE also argues the request for targeted marketing as part of the AIM Initiative is distinct from any funding SCE has available for mass-non-targeted paperless billing campaigns.⁸⁹¹

Similarly, SCE argues AIM funding for Communications to Update Contacts is distinct from other customer communications directed at customers in HFRAs; whereas the AIM Initiative will focus on customers in HFRAs and those who have a registered MyAccount through SCE.com, PSPS communications have separate funding requirements and provide customers in HFRAs with wildfire-related information.⁸⁹²

Regarding TURN's proposed reduction for the CPP education, SCE upholds that providing education after customers are defaulted to CPP is important for helping customers to manage their energy use and bill impacts and in deciding whether to stay enrolled in CPP. For Building Electrification, SCE clarifies the \$0.831 million in funding will be used in research for campaign positioning (*i.e.*, positioning testing, online panels, qualitative focus groups), campaign development, and media buys, and SCE asserts that its existing mass media campaigns have dedicated messages that are focused on unique communication goals that cannot be shifted to the Building Electrification program.⁸⁹³

Lastly, SCE challenges NDC's recommendations concerning in-language outreach and future tracking and reporting at the Energy Education Centers.

⁸⁹¹ *Id.* at 30-34.

⁸⁹² *Id.* at 34-35.

⁸⁹³ *Id.* at 35-36.

SCE asserts it already uses up-to-date information for targeting non-English speaking communities and is currently using more recent 2014-2018 American Community Survey (ACS) data that became available in 2019. SCE also already partners with CBOs and faith-based organizations to communicate with its underserved and hard-to-reach customer segments, and asserts it has been transparent during the discovery process regarding how it determines which communities it will target with in-language outreach.

SCE also argues it is unnecessary and impractical to track ethnicity demographics for individuals who attend; that SCE already captures participants' zip code (if provided), which can be used to determine whether a participant is a member of a disadvantaged community as identified by the California Energy and Pollution Act; that gathering data on the ethnicity of workshop and seminar participants would complicate SCE's compliance with the California Consumer Privacy Act, which requires that SCE provide, upon request, a comprehensive privacy report that includes the specific pieces of information SCE collects about that person; that tracking costs at the individual event level would be overly burdensome; and that NDC has provided no evidence that collecting individual event costs would actually assist the Commission or intervenors to better evaluate the Energy Education Centers.⁸⁹⁴

19.1.2.1.3. Discussion

We reject SCE's funding request for the AIM Initiative for two main reasons: first, we are not convinced, based on the evidence before us, that SCE considered all potential cost savings and existing programs/alternative revenue streams in its forecast methodology, calling into question the purported costs

⁸⁹⁴ *Id.* at 37-40.

and benefits of the AIM initiative. SCE already operates paperless billing/self-service campaigns through a variety of media channels;⁸⁹⁵ if these mass, non-targeted campaigns are not as effective as targeted campaigns,⁸⁹⁶ it is unclear why SCE cannot divert some of the existing campaign funding towards more targeted campaigns, rather than funding overlapping campaigns with similar objectives. Additionally, SCE does not identify any cost reductions for its existing analytics and marketing labor costs as a result of the AIM Initiative, which we would expect to further reduce the net AIM costs. Lastly, almost 40 percent of the proposed AIM funding (\$2.1 million out of \$5.2 million)⁸⁹⁷ is to update customer contacts; while we appreciate the purpose of the AIM Initiative is distinct from, and would reach a larger audience than, the wildfire-related information included in PSPS communications, SCE's PSPS outreach efforts already provide opportunities for customers located in HFRA's to update their contact information⁸⁹⁸ and it is not clear whether an additional initiative is needed to update contact information for these customers.

Second, in light of the significant capital expenditures and O&M expenses approved in this decision, as well as the general economic uncertainties associated with COVID-19, we are not convinced that now is the appropriate time to fund this discretionary program. Over the GRC period, SCE's AIM Initiative would cost ratepayers an annual net cost of \$1.856 million at a time when approximately 55 percent of SCE's customers are already expected to be

⁸⁹⁵ Ex. PAO-08WP at 26-30.

⁸⁹⁶ Ex. SCE-14 at 33.

⁸⁹⁷ Ex. SCE-03, Vol. 02 WP at 9.

⁸⁹⁸ Ex. SCE Tr.2-01, Vol. 1 at 50-51.

enrolled in electronic billing by 2021.⁸⁹⁹ SCE also purports that the AIM Initiative would result in greater customer satisfaction,⁹⁰⁰ but the degree to which customer satisfaction would improve through updated customer contact information, delivering more targeted communications, and reducing costs by conducting self-service campaigns is speculative.

With regard to SCE' proposed adjustments to support greater awareness and education of CPP and Building Electrification, we approve SCE's request for CPP funding (\$0.217 million) but not for Building Electrification (\$0.831 million). As clarified by SCE, the amount of CPP funding is less than half of what was spent in previous years, and we agree it is important to provide existing CPP customers with ongoing information regarding their performance during the event season so that they can make informed decisions about whether to stay enrolled in CPP. For Building Electrification, we find that SCE has not sufficiently addressed whether any of its existing mass media buys could be shifted to fund the proposed Building Electrification campaign. While SCE attempts to argue that its existing authorized mass media campaigns are still needed and have dedicated messages focused on unique communication goals,⁹⁰¹ as noted by TURN, one of the campaigns SCE cites to as being still needed (Summer Campaigns) is no longer running.⁹⁰²

With the adjustments described above, we authorize \$4.412 million in TY O&M for Customer CE&O. This amount incorporates: (1) a reduction of \$5.2 million for the AIM Initiative, (2) the addition of \$1.25 million in projected

⁸⁹⁹ Ex. PAO-08WP at 4-5.

⁹⁰⁰ Ex. SCE-14, Appendix A at A-27.

⁹⁰¹ Ex. SCE-14 at 36; SCE OB at 171; and SCE RB at 95.

⁹⁰² TURN OB at 127.

AIM savings (which would only be realized if the AIM effort is funded), and (3) a reduction of \$0.831 million for additional awareness and education related to Building Electrification.

Lastly, we find merit in NDC's recommendations to improve outreach efforts to minority communities. SCE's service area is home to some of the most diverse populations in the nation, where 20 percent of customers speak English less than "very well,"⁹⁰³ making it especially critical that SCE track and evaluate the effectiveness of its outreach efforts to minority communities. As discussed below, we believe NDC's recommendations could be reasonably incorporated into existing operations and filings, but many would benefit from further development in SCE's next GRC application.

While SCE asserts it uses the latest information provided by ACS, it never directly addresses NDC's broader point that ACS data is only published every five years. Because the large IOUs operate on a four-year rate case plan,⁹⁰⁴ and SCE currently uses 2014-2018 ACS data that became available in 2019,⁹⁰⁵ it is feasible that more current ACS data will not be available prior to SCE's next GRC filing. Therefore, we direct SCE to include testimony with its next GRC application describing how current ACS data compares with more up-to-date information from the U.S. Census Bureau, whether SCE used the more up-to-date information, and why or why not. In addition, while SCE already leverages CBOs and faith-based organizations to reach smaller ethnic groups, as an advocacy organization comprised of community-based, faith-based, and non-profit leaders, NDC is well positioned to help SCE identify any CBOs that may

⁹⁰³ Ex. SCE-03, Vol. 2 at 35.

⁹⁰⁴ SCE's next GRC application is due in May of 2023. (See D.20-01-002 at Appendix B).

⁹⁰⁵ SCE OB at 172.

be excluded from SCE's outreach efforts. Therefore, we direct SCE to meet with NDC to further develop the list of CBOs currently utilized. SCE shall include a summary of the meeting(s), as well as a description of the specific communities SCE intends to target with in-language outreach, as part of its next GRC application.

Regarding SCE's Energy Centers, one of the reasons SCE argues against collecting demographic information is that it would require costly modifications to SCE's online and in-person enrollment system. SCE does not offer any specific cost estimates for these modifications, and we agree with NDC that providing such cost information would be helpful in determining whether the ability to track information about participants' ethnicity is reasonable. Therefore, we direct SCE to include in its next GRC application specific cost estimates that would be needed for SCE's online and in-person Energy Center enrollment systems to track demographic information.

Finally, while we will not require SCE to provide a detailed, itemized breakdown of the expenditures incurred for seminars and workshops conducted by the Energy Centers, on the basis that such tracking appears complex and would require the manual collection of direct cost data across SCE, we agree with NDC that it is reasonable for SCE to provide some measure of the expenditures incurred for seminars and workshops to better evaluate future Energy Center facility upgrades and additions. Therefore, as part of SCE's next GRC filing, we direct SCE to provide an estimate⁹⁰⁶ of the annual expenditures for operating the Energy Centers, broken down (at a minimum) by in-person and online offerings, and divided by the total number of events (seminars,

⁹⁰⁶ Taking into consideration the range of overhead facilities costs and SCE personnel that conduct the seminars and workshops.

workshops, classes, etc.) offered that year. SCE should also provide an estimate of the average number of attendees enrolled in each event. While we understand and appreciate SCE's point that the direct costs are but one of several factors when considering program improvements, we believe it reasonable to provide this basic level of data both to support future Energy Center expenditures and to better understand how participants are engaging with the classes and seminars offered.

19.1.2.2. Escalated Complaints and Outreach

Escalated Complaints and Outreach work includes receiving and gathering feedback from customers and answering customer inquiries, resolving customer complaints, and improving customers' experiences with SCE programs and services. SCE handles escalated customer inquiries and complaints transferred from the Commission's Consumer Affairs Branch and those received directly by SCE through various channels. In performing its outreach function, the Escalated Complaints and Outreach department advocates for SCE's most vulnerable customers, such as those enrolled in SCE's Medical Baseline and critical care programs, as well as elderly and disabled customers. For critical care customers, SCE provides additional outage assistance and helps to avoid credit disconnections.⁹⁰⁷

SCE's 2021 TY O&M forecast for Escalated Complaints and Outreach is \$1.303 million. SCE's forecast is based on the 2018 base year amount (\$1.165 million) plus an additional \$0.142 million for increased labor to manage increased social media communications and to perform issue resolution from

⁹⁰⁷ Ex. SCE-03, Vol. 2 at 27-29.

SCE's Voice of the Customer initiatives,⁹⁰⁸ as well as a \$4,000 decrease in non-labor expenses stemming from SCE's Operational Excellence initiatives.⁹⁰⁹

Cal Advocates evaluated SCE's request for Escalated Complaints and Outreach and finds the forecast reasonable.

NDC recommends SCE track and report in future testimony customer complaints and inquiries to identify and target those customers facing the most service issues. Without analyzing customer complaints by language or channel, NDC asserts that SCE is not able to determine which customer groups primarily report complaints to SCE's Consumer Affairs Organization, impacting SCE's ability to measure the effectiveness of existing outreach to diverse communities.⁹¹⁰

In response, SCE asserts that NDC's recommendation is vague and unsupported, as inquiries received through social media or by contacting SCE's Customer Contact Center are unrelated to the Consumer Affairs Organization. SCE also asserts that the effectiveness of outreach activities is better measured by SCE's Customer Experience Management or Business Customer Divisions, which are tasked with analyzing the effectiveness of outreach campaigns, and that SCE lacks the processes and systems to be able to track each inquiry and complaint by social media channel.

⁹⁰⁸ "Voice of the Customer" is a program that collects customer feedback about their experiences with and expectations of SCE services and performance. It is used by operational and program teams to identify improvement opportunities that drive easier and more satisfying customer experiences. Feedback is gathered through transactional surveys after a customer interacts with SCE through one of several channels (*e.g.*, live agent interaction, website login, interactive voice response). (*See* Ex. SCE-03, Vol. 5 at 7, fn. 4.)

⁹⁰⁹ Ex. SCE-03, Vol. 2 at 32-34.

⁹¹⁰ Ex. NDC-01 at 29-30.

We find reasonable and approve SCE's uncontested TY O&M forecast of \$1.303 million for Escalated Complaints and Outreach.

Concerning NDC's recommendations, we agree that tracking inquiries and complaints by language could be useful in the evaluation of SCE's outreach efforts, since it would provide another means to gauge the effectiveness of SCE's existing outreach to minority communities. SCE does not discuss the ability or cost limitations of tracking inquiries and complaints by language using the existing Sprout Social system. To the extent the Sprout Social system can accommodate the tracking of this information with minimal or no modifications, we direct SCE to begin tracking this information immediately; otherwise, SCE shall report the costs to modify its Sprout Social system to be able to track language information as part of its next GRC filing. Regarding NDC's other recommendation to track complaints and inquiries by channel, it is unclear how tracking individual social media channels (*e.g.*, Facebook, Twitter, or Instagram) would yield better information than SCE's more aggregate tracking method (*e.g.*, written, telephone, informal, and social media (in aggregate)) in determining "which customer groups primarily report complaints to the Consumer Affairs Organization."⁹¹¹ Therefore, we will not require SCE to collect additional information by specific media channel.

19.1.2.3. External Communications

The External Communications work activity is primarily carried out by SCE's Corporate Communications organization, which educates external audiences on a range of topics, including safety, outages and storms, and clean energy. To achieve maximum customer and public awareness, messages are

⁹¹¹ Ex. NDC-01 at 29.

delivered in multiple languages through a variety of media channels, including newspapers, television, radio, out-of-home channels (such as billboards and bus shelters), and digital media channels. The process for conducting these communications is managed through: (1) public education, (2) key initiatives/media relations, and (3) digital communications.⁹¹²

As identified in SCE's RAMP Report, public education is one of the controls used to reduce the risk of contact with energized equipment. SCE states that safety messaging is a top priority for all audiences, and the importance of this activity is underscored by research demonstrating a strong correlation between safety advertising spend and customer awareness of actions that can be taken to mitigate risk. External Communications activities also mitigate the risk of customers not having potentially life-saving information during major crises and catastrophes.⁹¹³

SCE's TY O&M forecast for External Communications is \$11.313 million. SCE's forecast is based on recorded 2018 expenses (\$11.139 million) plus an adjustment of \$0.174 million for increases in software licensing, mailing costs for at-risk work safety messaging, and license fees for access to firewalled news content and research.⁹¹⁴

Cal Advocates finds the O&M forecast for External Communications reasonable.⁹¹⁵ No other intervenors oppose SCE's forecast. We find reasonable and approve SCE's uncontested TY O&M forecast of \$11.313 million for External Communications.

⁹¹² Ex. SCE-03, Vol. 2 at 4 and 35.

⁹¹³ *Id.* at 36-39.

⁹¹⁴ Ex. SCE-14 at 43.

⁹¹⁵ Ex. PAO-08 at 15.

19.1.3. Customer Contacts

Customer Contacts activities include the various channels for customers to interact with SCE. These activities are performed by SCE's (1) Customer Contact Center (CCC), which focuses primarily on residential customers, but is also the initial point of contact for small-medium non-residential customers; (2) Business Customer Division (BCD), which handles interactions with large non-residential customers and more complex small-medium non-residential customers; and (3) Digital Operations and Management group, which provides SCE.com and other digital channels.

The combined TY O&M forecast for Customer Contacts is \$68.923 million.⁹¹⁶ SCE states its Customer Contacts O&M request is responsive to D.18-12-013, which requires the utilities to apply new or revised disconnection rules, as well as Resolution ESRB-8, which requires electric utilities to make reasonable and appropriate attempts to notify customers of a de-energization event prior to performing de-energization.⁹¹⁷ For 2019-2021, SCE also forecasts \$3.605 million in capital expenditures for the CCC.⁹¹⁸

19.1.3.1. Customer Contact Center

The CCC handles approximately 16.6 million inbound calls annually through SCE's nearly 400 Energy Advisors, Interactive Voice Response (IVR) system,⁹¹⁹ and contract call center.⁹²⁰ SCE's CCC also responds to customer

⁹¹⁶ Ex. SCE-14 at 44, Table IV-9.

⁹¹⁷ Ex. SCE-03, Vol. 4A at 5-6.

⁹¹⁸ *Id.* at 45, Table IV-11.

⁹¹⁹ The IVR system interacts with callers, provides self-service capabilities, and routes calls to the appropriate recipient. The system currently has 165 applications that handle call routing, account access, credit, payment/extension, outage, and individual program inquiries. (Ex. SCE-14 at 56.)

⁹²⁰ Number of inbound calls based on 2014-2018 data. (Ex. SCE-03, Vol. 4A at 3.)

inquiries through alternative channels, such as web chat, mail correspondence, or Teletypewriter channels. In-house multilingual representatives allow the CCC to serve customers in six languages (Spanish, Cambodian, Chinese (Mandarin and Cantonese), Korean, and Vietnamese), while a vendor translation service provides support for customer inquiries in over 180 additional languages.⁹²¹

From 2014 to 2018, SCE reports that live-agent inbound call volume decreased by 23 percent while IVR-completed call volume increased by 34 percent. SCE indicates this trend primarily reflects the increase in customer use of the IVR self-service channel to complete more routine transactions, such as billing and payment. SCE's live agents also respond to 911 calls from local police and fire agencies to quickly access SCE personnel and resources.⁹²²

SCE forecasts \$45.062 million in total O&M expenses for the CCC, a decrease of \$0.332 million from SCE's base year O&M expenses of \$45.394 million.⁹²³ SCE's forecast is based on 2018 recorded expenses with a decrease to reflect SCE's Operational Excellence initiatives⁹²⁴ and an increase in the volume of anticipated CCA-related calls.⁹²⁵

Cal Advocates reviewed SCE's TY O&M forecast for the CCC and finds the amount reasonable.⁹²⁶ No party contested SCE's O&M forecast.

⁹²¹ Ex. SCE-03, Vol. 4A at 9-10.

⁹²² *Id.* at 10-14.

⁹²³ Ex. SCE-03, Vol. 4A at 19.

⁹²⁴ SCE's Operational Excellence initiatives include the reduction of customer live-agent calls through the provision of self-service options, workforce optimization and reduction through natural attrition, and directing calls to the contract call center. (Ex. SCE-03, Vol. 4A at 16 and 18-19.)

⁹²⁵ Ex. SCE-03, Vol. 4A at 17-20.

⁹²⁶ Ex. PAO-08 at 23-24.

We find reasonable and approve SCE's uncontested TY O&M forecast of \$45.062 million for the CCC.

19.1.3.2. Business Account Management

The Business Account Management function encompasses a variety of activities for SCE's business customers, ranging from basic customer care functions (*e.g.*, resolving billing, metering, credit/payment issues) to more comprehensive support (*e.g.*, educating customers on complex bill components, utility tariffs, resolution of repair and maintenance outages, interconnection and added facilities agreements, distribution service requests). The services and information provided by Business Account Management fall within four categories: (1) account management activities, (2) technical support services, (3) outage experience, and (4) other supporting services. Under SCE's current customer engagement model, account management resources are assigned to business customers based on the complexity of operations, service needs, energy use, and other customer-specific factors.⁹²⁷ Business Account Management is also responsible for policy development related to streetlights and for providing customer interface between SCE and customer owned streetlights.⁹²⁸

SCE's TY O&M forecast for Business Account Management is \$19.678 million. SCE's forecast is based on 2018 recorded costs (\$14.136 million) plus two adjustments: first, an additional \$5.169 million for increased account management and related support activities.⁹²⁹ This adjustment is comprised of \$2.689 million for increased account manager support for customer Transportation Electrification (TE) adoption and TE programs, and \$2.480

⁹²⁷ Ex. SCE-03, Vol. 4A at 21-22.

⁹²⁸ *Id.* at 31.

⁹²⁹ Ex. SCE-14 at 46.

million for increased account manager support for Customer Care, Grid Resiliency, and Distributed Generation.⁹³⁰ SCE states it expects 2021 energy efficiency (EE) portfolio funding previously allocated to the Business Account Management activities to be reduced by a corresponding amount (*i.e.*, \$5.169 million), and will seek that reduction as part of the required EE Annual Budget Advice Letter (EE ABAL) process.⁹³¹

Second, SCE's forecast includes an increase of \$0.373 million for outage communications activities.⁹³² SCE states this increase is driven by the fact that outage communications, education, and notifications are expected to increase from 2018-2021 due to SCE's grid strengthening and modernization efforts, and the potential for PSPS outages.⁹³³

19.1.3.2.1. Intervenors

Cal Advocates recommends the 2018 funding level for Business Account Management (\$14.136 million) be adopted for 2021, with no adjustments.⁹³⁴ Cal Advocates argues SCE's 2021 forecast is excessive compared to historical levels, including a 300 percent increase in the number of customer interactions in the TY for SCE's TE programs; that the overall number of interactions for all other programs decreased from 2018 to 2019; that SCE has not clearly delineated the sources of funding for account support that it receives from the TE portfolio or the Charge Ready Phase 2 program, and that SCE needs to be more transparent in identifying the work activities and funding sources to ensure

⁹³⁰ *Id.* at 51; SCE OB at 174.

⁹³¹ Ex. SCE-03, Vol. 4A at 38, fn. 44.

⁹³² Ex. SCE-14 at 46.

⁹³³ Ex. SCE-03, Vol. 4A at 39-43.

⁹³⁴ Ex. PAO-08 at 25.

ratepayers are not paying twice for SCE services; and that, contrary to SCE's claim that its GRC request will not impact customer rates (since SCE plans to seek a corresponding reduction as part of the EE ABAL process), any increase for account management activities will result in an increase in customer rates.⁹³⁵

Focusing only on the labor portion of SCE's Business Account Management forecast, TURN recommends the Commission reduce SCE's forecast by \$5.161 million⁹³⁶ for increased account management and related support and outage activities. TURN questions why current emerging technologies require more account manager resources than three years ago, and observes that projects for DERs and energy storage have been slowing down. TURN also shares Cal Advocates' concern regarding whether the increase in GRC funding for account management activities will be matched by a corresponding reduction in SCE's EE ABAL process.⁹³⁷

19.1.3.2.2. SCE Response to Intervenors

In response, SCE states its TE programs are only expected to address a third of the incremental TE market between 2020-2023, while Business Account Management must respond to all customers' needs, regardless of their participation in a TE Program. In addition, SCE highlights that TE-related account manager interactions in 2019 increased by 360 percent since 2017 and 74 percent since 2018. SCE argues continued customer interest in TE, currently

⁹³⁵ *Id.* at 27-30.

⁹³⁶ SCE's total adjustment of \$5.542 million is comprised of \$5.161 million in labor and \$0.381 million in non-labor. (Ex. SCE-03, Vol. 4A WP at 13.)

⁹³⁷ Ex. TURN-06 at 14-16.

approved TE programs, and the expected approval of Charge Ready Phase 2 all support the reasonableness of SCE's forecast.⁹³⁸

Further, SCE asserts the account manager TE-related funding being requested in this GRC is distinct from funding SCE receives from TE programs, encompassing issues such as responding to customer questions regarding electric vehicle (EV) tariff provisions and rate options, service capacity, coordination with customers on outage management, and meter installations. Additionally, SCE states Business Account Managers provide education and support to build the pipeline of customers for SCE's TE programs.⁹³⁹

Similarly, SCE argues its adjustment for account management support of Customer Care, Grid Resiliency, and Distributed Generation is reasonable and should be adopted. SCE asserts Cal Advocates' reported 2018-2019 reduction in FTEs ignores the forecasted labor increase for 2020-2021, and that SCE expects an increase in demand for account management support as it moves forward with grid modernization efforts and DER projects. Regarding the reported decrease in DER projects during 2018-2019, SCE states that TURN ignores the increased growth in energy storage capacity during the same timeframe.

SCE confirms that its September 1, 2020 submission of its 2021 EE ABAL included a \$5.169 million reduction for Business Account Management, and states that concerns about SCE making a corresponding reduction are misplaced. Even if the Commission adopts SCE's requested increase in GRC funding, SCE argues this will not, in itself, lead to an increase in rates.⁹⁴⁰

⁹³⁸ Ex. SCE-14 at 48-49.

⁹³⁹ *Id.* at 49-51.

⁹⁴⁰ SCE OB at 177-178.

Lastly, SCE argues that Cal Advocates and TURN provide no evidence or testimony supporting the proposed rejection of SCE's TY adjustment for outage communications.⁹⁴¹

19.1.3.2.3. Discussion

Review of recent Business Account Management trends indicate fewer overall account manager interactions and associated staffing needs: Comparing 2016 to 2019, the total number of account manager interactions increased by just 1 percent, and decreased by 12 percent from 2018-2019. The number of FTEs also decreased 8 percent from 2018-2019, from 115 to 106 FTEs.

SCE's projections related to the increase in emerging technologies largely hinge on SCE actively creating a pipeline of customers who enter the various application processes, as well as those who adopt an emerging technology outside of SCE's TE programs, with more time needed to address basic customer care needs. With respect to TE activities, we find the activities described in SCE's testimony are very similar to activities in other TE proceedings, including most recently the authorization of \$4.8 million in SCE's Charge Ready 2 Application to expand SCE's existing TE Advisory Services for commercial, government, small business, and fleet-operators.⁹⁴² SCE's existing TE Advisory Services range from initial awareness to TE training, hands-on-experience, TE-related assessments, and grant writing support,⁹⁴³ and appear similar to the types of activities SCE requests to fund in this GRC. Overall, we find the amount approved in SCE's Charge Ready 2 Application to be sufficient to cover the activities and level of

⁹⁴¹ Ex. SCE-14 at 54.

⁹⁴² D.20-08-045 at 111.

⁹⁴³ *Id.* at 106 and 108.

staff SCE anticipates needing for TE-related account manager activities over this GRC period.

With respect to DERs, based on SCE's 2018-2023 DER forecast⁹⁴⁴ we do not observe significant incremental growth in either distributed generation or energy storage projects that would warrant additional FTEs. Further, while SCE points to the growth in energy storage between 2018-2019, SCE's own projections for 2020-2023 show annual incremental levels of energy storage that are below the recorded 2018 amount.⁹⁴⁵ Therefore, we do not authorize any additional funding for account management and related support activities beyond SCE's recorded 2018 amount.

While Cal Advocates and TURN also oppose SCE's proposed increase of \$0.373 million for outage communications activities, neither Cal Advocates nor TURN provided any testimony, evidence, or explanation to support the rejection of this adjustment. We have reviewed SCE's workpapers and find the proposed adjustment for outage communications activities to be reasonable. Therefore, we authorize a total TY O&M forecast of \$14.509 million for Business Account Management activities.

19.1.3.3. Digital Operations and Management

The Digital Operations and Management group: (1) plans and manages the growth and evolution of SCE's digital presence and end-to-end digital customer experience; (2) designs and develops SCE's digital channels; and (3) provides daily content support of SCE.com digital services. SCE's digital channels (SCE.com, voice assisted devices, and mobile) make use of customer

⁹⁴⁴ Ex. SCE-14, Appendix A at A-84 through A-85.

⁹⁴⁵ *Ibid.*

feedback to create new or enhance existing features and functions, including tools to help customers make informed decisions, enroll in programs, conduct self-service transactions, and access their energy usage information.⁹⁴⁶

SCE asserts digital capabilities are foundational for improving the customer experience, and that SCE needs to continue to expand its self-service approach and deliver capabilities for the growing base of online customers. For example, SCE reports that from 2014-2018, the average year-over-year growth in visits to SCE.com was 14 percent.⁹⁴⁷ As SCE's online customers continue to increase in number, and as the breadth of digital device usage increases, SCE states it must continue to transform its digital channels to accommodate the basic needs and expectations of SCE customers.⁹⁴⁸

SCE forecasts TY O&M expenses of \$4.183 million for Digital Operations and Management.⁹⁴⁹ SCE's TY O&M forecast is based on 2018 recorded expenses (\$3.318 million) plus an increase of \$0.865 million in non-labor expenses driven by ongoing updates, enhancements, and stabilization of SCE.com and related support of evolving digital channels.⁹⁵⁰

Cal Advocates reviewed SCE's TY O&M forecast for Digital Operations and Management and finds the amount reasonable.⁹⁵¹

TURN recommends the Commission reject SCE's adjustment of \$0.865 million in non-labor expenses for improved digital services. TURN asserts

⁹⁴⁶ Ex. SCE-03, Vol. 4A at 45.

⁹⁴⁷ *Id.* at 46.

⁹⁴⁸ *Id.* at 45-48.

⁹⁴⁹ Ex. SCE-14 at 55.

⁹⁵⁰ Ex. SCE-03, Vol. 4A at 51-52.

⁹⁵¹ Ex. PAO-08 at 24.

the current funding level is working well: SCE's Digital Operations and Management has greatly improved customer engagement, while customer online usage trends have grown substantially from 2014-2019. Since SCE's investments have been successful, TURN asserts there is no indication that a higher level of funding is necessary. Further, TURN argues SCE does not provide justification for why it is unable to perform needed improvements using the current non-labor funding level.⁹⁵²

In response, SCE asserts the increase requested for non-labor expenses is well supported and primarily driven by ongoing updates, enhancements, and stabilization of SCE.com and related evolving digital channels, activities which SCE would not be able to perform under the current funding level.⁹⁵³

We find reasonable and approve SCE's TY O&M forecast of \$4.183 million for Digital Operations and Management. SCE's 2014-2018 data clearly shows significant, continual increases in all areas of online usage metrics, while the non-labor cost breakdown provided in SCE's workpapers appears defined and well supported. Further, we find SCE's forecasted increase and new IT projects, including the ongoing migration of SCE.com to a new cloud-based platform, to be reasonable and necessary to meet trends in customer engagement and demand.

19.1.4. Customer Care Services

Customer Care Services are comprised of SCE's efforts to: (1) measure, identify and prioritize customer service improvement opportunities to meet customer needs and expectations; (2) develop, manage, and deliver SCE's

⁹⁵² Ex. TURN-06 at 16.

⁹⁵³ Ex. SCE-14 at 55-56.

portfolio of customer programs and services; (3) provide specialized account management activities, such as CCA participation; and (4) lead SCE's TE initiatives.

SCE's Customer Care Services TY O&M forecast of \$29.805 million is based on 2018 recorded, adjusted expenses of \$22.768 million plus incremental adjustments in the Customer Experience Management, Business Account Management Services, Customer Programs Management, and TE Activities.⁹⁵⁴ SCE's proposed adjustments are described in greater detail below.

19.1.4.1. Customer Experience Management

Customer Experience Management (CEM) work activities include benchmarking studies, customized research, data analytics, and the collection and analysis of customer feedback to provide insights into the needs and expectations of SCE's customers. SCE uses Net Score⁹⁵⁵ as a data-driven measurement method to determine customer satisfaction on completed transactions and its Voice of the Customer (VOC) program.⁹⁵⁶ These data sets are merged with operational data to monitor and diagnose what drives a positive or negative customer experience, address customer issue points, and improve operational efficiencies. CEM also tracks utility satisfaction studies to benchmark SCE's performance against other large utilities; conducts post-program measurement and evaluation, custom research studies, and customer segmentation and propensity modeling activities; and manages

⁹⁵⁴ *Id.* at 60.

⁹⁵⁵ Net Score is based on the Net Promoter Score calculation measuring the difference between the percentage of survey respondents who gave a 9 or 10 rating (on a 10-point rating scale) minus the percentage of customers who gave a rating of 1-6. Those who gave a 7 or 8 rating are excluded from the Net Score Calculation. (*See Ex. SCE-03, Vol. 5 at 7, fn. 4.*)

⁹⁵⁶ *See* footnote 911, *supra*.

programs that help SCE comply with privacy-related laws and regulations from federal and state agencies.⁹⁵⁷

SCE forecasts \$7.398 million in TY O&M expenses for CEM activities. SCE's forecast is based on 2018 recorded costs (\$6.738 million) plus an increase of \$0.659 million for customer experience improvements.⁹⁵⁸ The customer experience improvements adjustment is comprised of: (1) \$0.283 million for two additional FTEs to follow-up with customers who have expressed dissatisfaction with SCE's service via the "Close the Loop" customer feedback program (also referred to as the Medallia VOP survey), and (2) \$0.376 million in non-labor costs to support data analysis and research to improve core customer experiences (*e.g.*, purchase of new external data and vendor staffing for data aggregation, purchase of secondary literature and vendor conducted focus groups, and vendor staffing for the design of pilot evaluations and data analysis).⁹⁵⁹

Cal Advocates reviewed SCE's request for CEM activities and finds the forecast reasonable.⁹⁶⁰

TURN recommends rejecting SCE's proposed increase of \$659,000 for customer experience improvement. TURN asserts that SCE has not established the need for two additional FTEs, and that SCE already performs the activities to be covered under the proposed non-labor increase. TURN also states that now is not the time to engage in unnecessary spending that further burdens ratepayers.⁹⁶¹

⁹⁵⁷ Ex. SCE-03, Vol. 5 at 7-9.

⁹⁵⁸ Ex. SCE-14 at 61.

⁹⁵⁹ Ex. SCE-03, Vol. 5 at 12-14.

⁹⁶⁰ Ex. PAO-08 at 31.

⁹⁶¹ Ex. TURN-06 at 17-18.

In response, SCE asserts that activities funded by the requested increase are distinct from other ongoing activities, and are necessary to more effectively manage customers' complaints and concerns. Due to limited resources, SCE states it only followed-up with 462 customers out of the 312,464 VOC surveys completed in 2019, and that the requested funding will ensure more consistent analysis of customer comments.

Regarding the non-labor adjustment, SCE asserts it needs to periodically refresh data from outside vendors to ensure SCE has accurate customer data variables; that SCE plans to use the additional funds to expand market research to accommodate new rate plans and programs; and that the additional funds will also be used to test the effectiveness of pilots geared towards specific customer service solutions and programs in meeting customers' needs.⁹⁶²

We find SCE has reasonably justified the requested increase of \$0.659 million for customer experience improvement. SCE indicates it followed up with less than 0.15 percent of the VOC surveys completed in 2019; VOC surveys are only useful, both to SCE and to customers who complete the survey, to the extent SCE can review and follow-up with the survey results. We expect the two FTEs approved in this decision to result in a more thorough and consistent analysis of customer comments moving forward. SCE also provides sufficient justification and detail to support its adjustment for non-labor expenses, and we agree with SCE that, especially in times of economic uncertainty, it is imperative for SCE to have a clear and comprehensive process for establishing customer concerns. Therefore, we authorize \$7.398 million in TY O&M expenses for CEM activities.

⁹⁶² Ex. SCE-14 at 61-62.

19.1.4.2. Business Account Management Services

Business Account Management Services is responsible for program service and delivery, as well as specialized account management activities for CCA, Direct Access (DA), Economic Development Services, Hydraulic Services, and Energy Related Services. CCA and DA providers purchase and sell electricity on behalf of utility customers within their service areas. In 2018, six CCAs were operational in SCE's service territory; by 2021, SCE forecasts this will increase to 26 operational CCAs, serving over 1.5 million service accounts. Economic Development Services works to identify and assist in retaining, expanding, and attracting businesses that have viable relocation opportunities outside of California, or that are facing potential closure. SCE's Hydraulic Services group is comprised of technical specialists trained in comprehensive testing and analysis of water and fluid pumping operations, and which SCE provides to its agricultural, supply/irrigation, and commercial and industrial customer segments. Lastly, Energy Related Services is a tariffed product that allows federal customers to use SCE's energy efficiency and project management expertise for energy efficiency or renewable energy projects.⁹⁶³

SCE's TY O&M forecast of \$5.009 million for Business Account Management Services is based on 2018 recorded costs (\$2.831 million) plus the following adjustments: (1) an increase of \$1.294 million for CCA/DA implementation and management; (2) an increase of \$1.151 million for Hydraulic Services; and (3) a reduction of \$268,000 for Energy Related Services.⁹⁶⁴

⁹⁶³ Ex. SCE-03, Vol. 5 at 15-22.

⁹⁶⁴ *Id.* at 25-29.

With the exception of SCE's request for a \$1.151 million increase for Hydraulic Services, SCE's forecast for Business Account Management Services is uncontested. Excluding SCE's adjustment for Hydraulic Services, which is discussed below, we find reasonable and approve the remainder of SCE's O&M forecast for Business Account Management Services (\$3.858 million).

In the past, funding for the Hydraulic Services activity has been split between the GRC and the EE balancing account. SCE indicates it intends to move the costs previously funded through its EE portfolio into the GRC since the Agriculture Energy Advisor EE program does not provide cost-effective benefits to the EE portfolio.

Cal Advocates recommends a reduction of the \$1.151 million for Hydraulic Services, and that the costs associated with Hydraulic Services continue to be recorded in SCE's EE portfolio funding. Cal Advocates' recommendations are based on the following assertions: (1) costs for Hydraulic Services are already funded through the EE portfolio and SCE has not provided adequate evidence to support recovery of these expenses through the GRC; (2) although SCE claims that it will seek to offset the increase through a corresponding \$1.4 million reduction in the 2021 EE ABAL process, Cal Advocates was not able to confirm the accounting treatment of these costs; and (3) it is unclear how SCE will be accounting for Hydraulic Services costs during the transition of SCE's portfolio to third-party implementors.⁹⁶⁵

TURN also recommends a reduction of the \$1.151 million for Hydraulic Services. TURN asserts that SCE is not simply moving costs from EE funding to the GRC; rather, SCE is asking for an increase in authorized costs for these

⁹⁶⁵ Cal Advocates OB at 177-178.

activities. TURN highlights that an examination of historical pump test numbers reveal that activity levels have not increased, and that increased funding would be unreasonable. TURN also argues that GRC funding should not be increased simply because SCE plans to reduce EE spending in the future.⁹⁶⁶

In response, SCE asserts it is not seeking an increase in overall authorized costs for Hydraulic Services; rather, due to a change in Commission rules related to SCE's EE portfolio, SCE is simply moving the portion of its pump test costs presently funded through the EE balancing account to its GRC. SCE asserts these pump tests have become a routine practice for customers to understand their energy efficient operations, to ensure optimal pump performance, and to minimize operational and possible financial impacts. Lastly, SCE states it requested closure of the Agricultural Energy Advisor program in its 2021 EE ABAL submitted on September 1, 2020, so there is no risk of duplicative funding for pump services.⁹⁶⁷

Parties do not dispute the need for Hydraulic Services; rather, the primary point of contention concerns the potential duplication or increase of authorized costs for these activities. SCE's proposed 2021 EE budget request was approved via an Energy Division Disposition letter dated December 28, 2020.⁹⁶⁸ In the corresponding Advice Letter, SCE proposed to remove all costs for the Pump Test sub-program, also referred to as Hydraulic Services.⁹⁶⁹ SCE's Advice Letter

⁹⁶⁶ Ex. TURN-06 at 18-19; TURN OB at 135-136.

⁹⁶⁷ SCE OB at 180-182; SCE RB at 101-102.

⁹⁶⁸ December 28, 2020 Energy Division Disposition of SCE's Advice Letters (AL) 4285-E and 4285-E-A (EE Disposition Letter). Note, while the EE Disposition Letter approved SCE's EE budget request, it rejected SCE's EE business plans. (See EE Disposition Letter at 1-2.)

⁹⁶⁹ See EE Disposition Letter at 35; SCE AL 4285-E at 23 and Attachment E at E-7.

also indicates that the 2020 EE budget for Hydraulic Services was \$1.243 million.⁹⁷⁰

We find the disposition of SCE's 2021 EE budget, including the removal of EE funding for Hydraulic Services, provides reasonable assurance that customers will not be paying twice for pump services if SCE's GRC request is approved. Further, the level of 2021 GRC funding is consistent with (and slightly below) SCE's 2020 EE budget for Hydraulic Services. We also agree with SCE that it is unlikely a third-party EE implementor would include pump test services in an agricultural bid, since pump tests themselves no longer produce reportable EE savings, but accept SCE's commitment to track any of the third-party agricultural programs that include pump services and to alter its next GRC funding request accordingly. Overall, we find SCE has provided reasonable assurances against the duplication of funding for Hydraulic Services, and find the proposed level of funding to be reasonable. We also find the continuation of these services to be useful to agricultural and water customers in maintaining efficient pumping operations and performance. SCE is directed to report in its next GRC filing whether any of the third-party agricultural programs include pump services, and alter its GRC funding request accordingly.

Including SCE's adjustment for Hydraulic Services results in a total approved TY O&M forecast of \$5.009 million for Business Account Management Services.

19.1.4.3. Customer Programs Management

Customer Programs Management work includes the planning, implementation, and management of customer programs in the areas of program

⁹⁷⁰ See EE Disposition Letter at 139; SCE AL 4285-E Attachment G at G-1.

innovation and pilots, energy management tools, rate-based solutions, pricing, building electrification, and DER programs. SCE states innovation and pilot activities have resulted in several customer offerings, including programs such as TOU peak period alerts and an Appliance Energy Use Cost Estimator on SCE.com, and that these examples add to the existing portfolio of customer services and energy management tools. In addition, SCE's Customer Programs Management group oversees Commission-required programs and initiatives; manages behind-the-meter DER energy procurement for reliability-driven requests for offers; conducts research, analysis, and program development to support building electrification and California's greenhouse gas reduction goals; and conducts outreach for the Cool Center program⁹⁷¹ through press releases, customer contact center staff training, social media, and bill inserts.⁹⁷²

SCE's 2021 TY O&M forecast for Customer Programs Management is \$13.832 million. SCE's forecast is based on recorded 2018 costs (\$13.199 million) plus the following adjustments: (1) an increase of \$0.528 million for additional FTEs to manage and support behind-the-meter DER reliability contracts. SCE indicates these positions were forecast in SCE's 2018 GRC but were not filled pending a final decision on SCE's 2018 GRC proceeding; (2) an increase of \$0.984 million for additional FTEs and non-labor to support building electrification activities, as well as to support and inform the CPUC's Building Decarbonization Rulemaking (R.19-01-011); (3) an increase of \$0.100 in non-labor

⁹⁷¹ Cool Centers provide a safe, cool space for customers in extreme heat climate areas, offering relief from heat for customers who do not have cooling devices in their homes or in lieu of running their own cooling devices. SCE previously funded its cool centers through its income-qualified program applications; however, in D.16-11-022 the Commission directed SCE to request Cool Center funding through its GRC filing. (See Ex. SCE-03, Vol. 5 at 35-36; also, D.16-11-022 at 333-334.)

⁹⁷² Ex. SCE-03, Vol. 5 at 30-36.

O&M expenses to expand Cool Center locations and operating hours; (4) an increase of \$0.458 million in labor expenses for additional FTEs to support an increase in NEM application volume; and (5) a reduction of \$1.436 million for prior education and outreach efforts related to CPP default and new TOU periods that will not be required in the TY.⁹⁷³

Cal Advocates reviewed SCE's request for Customer Program Management and finds the underlying forecast reasonable.⁹⁷⁴

TURN recommends the rejection of SCE's proposed \$0.458 million increase in labor to support the projected increase in NEM applications. TURN observes that NEM applications in 2019 were lower than NEM applications in 2015. TURN also highlights that SCE made the same argument during the 2018 GRC, projecting that NEM applications would increase to an average of 112,247 in 2018-2020, when in reality the average for 2018-2019 was less than half of SCE's projection.⁹⁷⁵

In response, SCE asserts that no party, including TURN, challenged the accuracy of SCE's Solar Photovoltaic Forecast Model or provided credible data indicating that SCE's forecast is unrealistic; that TURN cherry-picked data comparing the volume of 2019 NEM application with that of 2015, while ignoring the more significant growth of NEM applications between 2018-2019; and that the number of NEM interconnection applications is expected to increase substantially over the next several years due to the new 2019 Building Energy Efficiency Standards which became effective on January 1, 2020.⁹⁷⁶

⁹⁷³ *Id.* at 39-44.

⁹⁷⁴ Ex. PAO-08 at 31.

⁹⁷⁵ Ex. TURN-06 at 19.

⁹⁷⁶ Ex. SCE-14 at 68-69; SCE OB at 182-183.

Notwithstanding SCE's overestimation of NEM applications in the past, SCE's current projection of 100 percent growth in NEM applications is largely based on the 2019 Building Energy Efficiency Standards requirement that all new low-rise residential buildings include solar photovoltaic systems, which became effective January 1, 2020. Given this new requirement, we find it reasonable to expect some increase in NEM applications over historical levels. Since no party challenged the underlying assumptions in SCE's Solar Photovoltaic Forecast Model or provided an alternative forecast that accounts for the 2019 Building Efficiency Standards, we find SCE's projected growth in NEM applications, and the associated increase in FTEs to address those applications, to be reasonable. As part of SCE's next GRC application, we direct SCE to report how closely its current solar photovoltaic forecast compares with actual NEM solar applications received.

Aside from SCE's adjustment of \$0.458 million to support additional NEM applications, which we approve for the reasons provided above, SCE's forecast for Customer Programs Management is uncontested and appears reasonable. Therefore, we authorize SCE's total TY O&M forecast of \$13.832 million for Customer Programs Management.

19.1.4.4. Transportation Electrification

As the lead organization of SCE's overall TE-related efforts, the TE group:

- (1) coordinates internal and cross-functional activities involving EVs and other forms of electric transportation (including goods and people movement);
- (2) evaluates market conditions through primary and secondary market research;

(3) generates customer and market programs that overcome barriers to adoption and optimize load; and (4) prepares approved programs for launch.⁹⁷⁷

SCE's TE group was newly formed in 2019 and SCE plans to have the group fully staffed in 2021. The TE group is made up of three teams: (1) the Strategy and New Program Development (Strategy) team, which leads efforts in conducting market research and developing market solutions that advance the awareness, availability, and affordability of EVs, and also prepares any approved program for launch; (2) the Business Development and Partnerships (Business Development) team, which leads TE policy, customer engagement, and outreach efforts to meet TE goals and objectives; and (3) the TE Operations (Operations) team, which is responsible for operational coordination, customer interface, and infrastructure deployment that spans multiple SCE operating units.⁹⁷⁸

SCE requests \$3.566 million for the new TE group. Since the TE group was formed in 2019, there are no historical expenses from 2014-2018. Instead, SCE's forecast is based on the following breakdown: (1) \$1.212 million for approximately ten FTEs for the Strategy team; (2) \$0.627 million for approximately five FTEs for the Business Development team; (3) \$0.976 million for approximately eight FTEs for the Operations team; and (4) \$0.750 million in non-labor costs for the TE group to attend and participate in TE-related conferences and external engagements.⁹⁷⁹

19.1.4.4.1. Intervenors

Cal Advocates recommends SCE's request for \$3.566 million be rejected in its entirety on the basis that SCE "currently receives funding in TE proceedings

⁹⁷⁷ Ex. SCE-03, Vol. 5 at 45.

⁹⁷⁸ *Id.* at 45-48.

⁹⁷⁹ *Id.* at 50-51.

for the activities performed by all three teams of the TE group outside of SCE's GRC."⁹⁸⁰ Cal Advocates states that SCE's TE proceedings, such as the Charge Ready Pilot (A.14-10-014), Charge Ready Bridge (A.14-10-014), Charge Ready Transport (A.17-01-021), and Charge Ready 2 (A.18-06-015), already provide capital and O&M funding for the types of activities described in SCE's testimony. In addition, Cal Advocates highlights that SCE is also awaiting a pending decision for \$760 million in capital and O&M expenses to be recovered through the Charge Ready Program Balancing Account. Cal Advocates concludes that SCE is not clear on the accounting treatment between the funding requests in this GRC and the TE proceedings, and is concerned that if SCE's GRC request is authorized ratepayers would likely pay twice for the same services. Cal Advocates also contends it is premature for SCE to request TE funding in this GRC when its TE portfolio is still being evaluated through the Charge Ready 2 Program application.⁹⁸¹

TURN supports the analysis of Cal Advocates, and agrees that SCE's request should be rejected in its entirety since the activities described in SCE's testimony are similar to activities in other TE proceedings. TURN also argues that SCE already engages in general promotion of TE and assistance to customers. Regarding the non-labor cost increase, TURN notes that conference sponsorships and trade group memberships generate good public relations for SCE and should not be funded by ratepayers; furthermore, "external engagement" sounds similar to lobbying activities and should be disallowed.⁹⁸²

⁹⁸⁰ Ex. PAO-08 at 34.

⁹⁸¹ *Id.* at 34-37; Cal Advocates OB at 178-182.

⁹⁸² Ex. TURN-06 at 19-20; TURN OB at 138-139.

19.1.4.4.2. SCE Response to Intervenors

In response, SCE states it performs two primary functions to help achieve the State's TE goals: (1) general promotion of TE, assistance to customers who are considering adopting TE, and development activities that precede the approval of a program, and (2) implementing and administering specific Commission-approved programs and pilots. SCE asserts its GRC funding request is limited to the former activities, which are separate and distinct from activities funded in individual TE programs. Considering all the activities that fall outside the scope and lifecycle of approved programs (such as trend monitoring and market analysis, generating ideas to accelerate TE and EV adoption, performing feasibility and impact analyses, etc.), SCE asserts its GRC proposal is very modest and not duplicative of individual TE programs. Further, SCE asserts that none of the parties have identified instances of duplicate funding, and that SCE's funding request is timely, since it does not contain potential costs related to post-Charge Ready Phase 2 activities and supports the State's TE and greenhouse gas-reduction goals. Lastly, SCE asserts the non-labor portion of its TE request is vital and does not include lobbying; rather, SCE uses speaking opportunities at conferences and other external engagements to move the industry forward in creating economies of scale and to help accelerate TE and EV adoption.⁹⁸³

19.1.4.4.3. Discussion

We find SCE has failed to justify why additional funds are needed for the TE group at this time. While SCE asserts it is only seeking funding for non-program costs that provide general promotion of TE and assistance to

⁹⁸³ Ex. SCE-14 at 69-77.

customers,⁹⁸⁴ SCE's existing TE funding already includes significant marketing, education, and outreach initiatives to promote TE adoption. For example, in the Charge Ready Pilot proceeding, SCE received \$3 million for education and outreach,⁹⁸⁵ which has funded activities such as targeting car buyers to help them gain awareness of EVs, an array of TE advisory services, market reporting, and a "Broad EV Awareness Campaign."⁹⁸⁶ The Commission recently approved an additional \$14.5 million for marketing, education, and outreach (ME&O) as part of SCE's Charge Ready 2 Application.⁹⁸⁷ Beyond the existing level of SCE's approved TE funding, we also note, as we did in the approval of SCE's Charge Ready 2 Application,⁹⁸⁸ that SCE has not demonstrated how its GRC request for general promotion of TE adoption leverages non-ratepayer funded TE ME&O activities.

Further, we agree with Cal Advocates that the accounting treatment of SCE's funding requests in this GRC are not clearly discernable from funding in the TE proceedings. For example, SCE admits that the non-labor expense amount of \$750,000 being requested in this GRC includes some of the same or similar activities included in Sponsorships, Research Reports, and other non-labor items as part of SCE's Charge Ready Pilot.⁹⁸⁹ SCE does not clearly explain why additional funds are needed for work activities that are the same or

⁹⁸⁴ *Id.* at 71.

⁹⁸⁵ D.18-12-006 at OP 2.

⁹⁸⁶ Ex. PAO-08 at 34-35 and 37.

⁹⁸⁷ D.20-08-045 at 2.

⁹⁸⁸ *Id.* at 110.

⁹⁸⁹ Ex. PAO-08WP, SCE's Response to Data Request PubAdv-SCE-029-DAO, Q.6b, at 53-54.

very similar to what is included in SCE's TE proceedings. For these reasons, we reject SCE's TY request of \$3.566 million for the new TE group.

19.2. Customer Interactions Capital

SCE forecasts combined 2019-2021 capital expenditures of \$4.441 million for Customer Interactions. Of that amount, Cal Advocates and TURN propose a reduction of \$3.605 million associated with SCE's Customer Contact Center.⁹⁹⁰

19.2.1. Customer Care Services Tools and Equipment

The Customer Interactions BPE includes capital expenditures to support SCE's Engineering and Design Solutions, Hydraulic Services, and Technology Test Center groups. These groups provide service to customers including, but not limited to, (1) evaluating energy consumption and performance of existing or new equipment being considered by customers and (2) on-site testing and evaluation of customer equipment.

SCE forecasts capital expenditures of \$0.836 million from 2019-2021 for specialized tools and equipment to be used by SCE's Hydraulic Services group and SCE's Technical Services group. SCE's forecast for Customer Care Services specialized tools and equipment used by engineers and pump test specialists is budget-based and considers the age and condition of the existing equipment.

We find reasonable and adopt SCE's uncontested 2019-2021 forecast of \$0.836 million for Customer Care Services specialized tools and equipment.

19.2.2. Customer Contact Center

SCE presented, for the first time in its rebuttal testimony, the forecasted costs for its IVR capital project after discovering the costs were inadvertently excluded from SCE's direct testimony. SCE began a system upgrade of the IVR

⁹⁹⁰ Ex. SCE-03, Vol. 3A at 101.

platform in 2018 after identifying a system integrity risk due to the IVR platform being operated on a version unsupported by its vendor. The table below provides a summary of recorded 2019 capital expenditures and SCE's forecast for the IVR project (Nominal \$000).⁹⁹¹

Customer Contacts	2019 Recorded	2020 Forecast	2021 Forecast	Total
IVR Capital Expenditures	1,635	1,770	200	3,605

SCE states that when vendors discontinue support for older versions of their product it becomes necessary for users to upgrade to a more current version or risk that the product will not function properly. SCE asserts the benefits of this project include cost avoidance (60 percent of calls route through the IVR annually without the need for Energy Advisor assistance), business resiliency, and customer satisfaction.⁹⁹²

SCE chose to implement the project over two phases to minimize operational disruptions and minimize impacts to customer experience and satisfaction. SCE also states it is "using a certified IVR implementor for this project with extensive knowledge of SCE's systems infrastructure, a proven track record of similar projects, and an overall hourly rate that was less than that of other vendors SCE has worked with in the past."⁹⁹³

TURN and Cal Advocates recommend no funding for the IVR project on the basis that SCE did not present evidence concerning this project until its rebuttal testimony. Cal Advocates asserts it did not have an opportunity to

⁹⁹¹ Ex. SCE-14 at 56, Table IV-13.

⁹⁹² *Id.* at 57-58.

⁹⁹³ *Id.* at 58.

evaluate SCE's claims, or conduct analysis of SCE's supporting workpapers, to determine if the utility's request was justified.⁹⁹⁴ TURN asserts 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; that SCE's request should be rejected on the basis of fairness alone; and that even if the Commission were to allow SCE's request to be considered SCE failed to show that the benefits of this project outweigh the costs.⁹⁹⁵

In response, SCE states that, while parties did not have an opportunity to provide written evidence about the project, TURN and Cal Advocates could have served data requests and moved to admit SCE's responses into the record and cross-examined SCE's sponsoring witness during hearings. SCE also contends the record demonstrates that the IVR project benefits outweigh the costs, while failure to upgrade the IVR platform would impact SCE's ability to serve customers through IVR.⁹⁹⁶

The Commission has consistently found that applicants have the burden of affirmatively establishing the reasonableness of all aspects of their requests in direct testimony,⁹⁹⁷ and that, based on the principle of fairness, rebuttal testimony is not the place to present requests or foundational evidence for the first time.⁹⁹⁸ SCE had plenty of time to update its direct testimony to include this

⁹⁹⁴ Cal Advocates OB at 186.

⁹⁹⁵ TURN OB at 131-132.

⁹⁹⁶ SCE RB at 100.

⁹⁹⁷ *Re San Diego Gas and Electric Company*, 46 CPUC 2d 538, 764, n. 17 (D.04-07-022); D.08-01-020 at 2; D.15-11-021 at 9.

⁹⁹⁸ D.04-03-039 at 54 and 84.

request but failed to do so. Further, it is unclear, based on the limited record before us, the specific process by which SCE selected the certified IVR implementor for this project, or how the overall cost estimate compares with other quotes received. Therefore, we do not authorize any funding for SCE's 2019-2021 Customer Contact Center capital expenditure request.

19.3. Customer Interactions – OOR, Service Fees, and Service Guarantees

SCE charges fees for services that are above the standard operational services provided by SCE, and which are not recovered through general rates. The revenue received for these services is accounted for as OOR. SCE has established fees associated with service connection charges (fees) for establishing service following disconnection for nonpayment of bills, returned check charges, and services associated with DA, CCA, and other special services.⁹⁹⁹ In addition, SCE's Service Guarantee program provides customers a \$30 bill credit whenever one of four service guarantee standards is not met.¹⁰⁰⁰ Service guarantees are currently shareholder funded pursuant to D.19-05-020. In this GRC, SCE requests \$985,000 in expenses for the Service Guarantee Program for 2021 to be paid for by ratepayers.¹⁰⁰¹

In testimony, SCE's TY Customer Interactions OOR, net of Service Guarantees credits (-\$985,000), was \$24.745 million.¹⁰⁰² SCE's OOR forecast is based on its proposed service fees as well as the historical record of activity

⁹⁹⁹ Ex. SCE-03, Vol. 6A at 1.

¹⁰⁰⁰ SCE's four service guarantees include: Timely and Accurate First Bill, Missed Appointment, 24 Hour Service Restoration, and 72 Hour Planned Outage Notice. A Service Guarantee claim may be made by a customer, but most occurrences are identified through SCE's own internal processes, procedures, and systems. (*Id.* at 63.)

¹⁰⁰¹ *Id.* at 1 and 66.

¹⁰⁰² Ex. SCE-14 at 3, Table I-3 and 80, Table VI-19.

levels and actual revenue collected from these activities. The TY forecast of \$24.745 million is \$3.155 million less than the 2018 recorded OOR, which SCE mainly attributes to: (1) decreased Late Payment Charge (LPC) OOR for residential and non-residential customers due to a cost-of-capital reduction and removal of the LPC charge from the generation portion of CCA customer bills, and (2) a reduction in the Return Check Charge.¹⁰⁰³ SCE's forecast for the Service Guarantee Program is based on a five-year average (2014-2018) of recorded volumes and costs.¹⁰⁰⁴

The SoCal CCAs initially opposed SCE's OOR forecast. On September 10, 2020, SCE and the SoCal CCAs filed a motion for adoption of a settlement agreement (SCE and SoCal CCAs Joint Motion) which would resolve all disputed issues between the two parties. As discussed in Section 52.2, we approve the SCE and SoCal CCAs Joint Motion for adoption of the settlement agreement, which results in a reduction of \$0.927 million to SCE's TY Customer Interactions OOR forecast.

TURN and Cal Advocates recommend the Commission reject SCE's request for ratepayer funding of service guarantees on the basis that SCE has not provided new or persuasive arguments. TURN and Cal Advocates highlight that SCE made the same requests for this program to be funded by ratepayers in the 2006, 2009, 2012, 2015, and 2018 GRCs, all of which were rejected by the Commission.¹⁰⁰⁵

¹⁰⁰³ Ex. SCE-03, Vol. 6A at 2.

¹⁰⁰⁴ *Id.* at 68-69.

¹⁰⁰⁵ Ex. PAO-08 at 38-39; Ex. TURN-06 at 20-21.

In response, SCE states that it delivers on service guarantee standards an average of 99.1 percent of the time,¹⁰⁰⁶ and that paying the service guarantee in about one percent of cases, rather than building “perfect” systems and processes, is a much more cost-effective solution for SCE’s customers. SCE further asserts that neither Cal Advocates nor TURN address SCE’s showing that the service guarantees are a reasonable cost of providing service; that the relevant question is not whether SCE will be incentivized to meet its service guarantees as often if they are ratepayer funded, but whether service guarantees are a reasonable cost of providing utility service; and that to guard against disincentivizing service guarantees, SCE recommends the Commission use a four-year average to establish a baseline upon which reasonableness can be measured in future rate cases.¹⁰⁰⁷

Consistent with numerous past SCE GRC decisions,¹⁰⁰⁸ we find that SCE has not presented a persuasive argument for ratepayer funding of service guarantees. The Commission did not establish the Service Guarantee Program with the goal of achieving a near 100 percent success rate, but rather to ensure there is no degradation to SCE’s current level of customer service.¹⁰⁰⁹ As the Commission most recently stated:

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

¹⁰⁰⁶ Ex. SCE-03, Vol. 6A at 62.

¹⁰⁰⁷ Ex. SCE-14 at 102-103.

¹⁰⁰⁸ See D.06-05-016 at 122; D.09-03-025 at 94; D.12-11-051 at 228; D.15-11-021 at 151; and D.19-05-020 at 133.

¹⁰⁰⁹ D.04-07-022 at 163-164.

most effective when it is paid by the shareholders, not ratepayers.¹⁰¹⁰

We continue to find the incentive to meet the goals of the Service Guarantee Program is most effective when paid for by shareholders, as evidenced by SCE's current 99.1 percent success rate. Therefore, SCE's request to have ratepayers fund service guarantees is denied.

We have reviewed and find reasonable the remaining uncontested elements of SCE's Customer Interactions OOR forecast. Considering the approved settlement agreement between SCE and the SoCal CCAs, and the removal of ratepayer funded Service Guarantee Standards, we approve a TY Customer Interactions OOR amount of \$24.803 million.

20. Business Continuation

The Business Continuation BPE enhances SCE's emergency response capabilities through programs and activities that identify hazards, perform mitigations, create contingency and response plans, and train SCE response teams. The Business Continuation BPE includes two main work activities: (1) Planning, Continuity, and Governance and (2) All Hazards Assessment, Mitigation, and Analytics.¹⁰¹¹

SCE forecasts combined 2021 TY O&M expenses of \$5.297 million and combined 2019-2021 capital expenditures of \$138.041 million¹⁰¹² for the Business Continuation BPE.¹⁰¹³

¹⁰¹⁰ D.19-05-020 at 133.

¹⁰¹¹ Ex. SCE-04, Vol. 1 at 1.

¹⁰¹² Including 2019 recorded capital expenditures of \$44.891 million. (Ex. SCE-15, Vol. 1 at 3.)

¹⁰¹³ *Id.* at 2-3.

Cal Advocates recommends a reduction of \$0.203 million to SCE's TY O&M forecast and a reduction of \$3.728 million to SCE's 2019-2021 capital expenditure request.¹⁰¹⁴ TURN recommends a reduction of \$26.511 million to SCE's 2019-2021 capital expenditure request.¹⁰¹⁵

20.1. Planning, Continuity, and Governance

The Planning, Continuity, and Governance work activity generates the annual Business Impact Analysis (BIA) that helps inform investment strategies and establishes priorities for contingency and emergency plans. The primary objectives of SCE's Planning, Continuity, and Governance activities are to: (1) standardize and strengthen the development of new and existing emergency and contingency plans, (2) quickly establish the continuity of operations as soon as possible following an emergency, and (3) execute governance over required compliance programs related to emergency management and response recovery. Team members establish and manage the development of plans for emergency response, business continuity, and disaster recovery, and have governance and oversight of these programs to track the effectiveness and compliance of the work. They also manage Business Resiliency department finances, track and report on performance metrics, and implement continuous improvement initiatives.

SCE forecasts \$1.315 million in TY O&M expenses for Planning, Continuity, and Governance. SCE's forecast is based on 2018 recorded costs plus a net increase of approximately \$0.134 million to account for (1) a decrease in labor costs due to the reassignment of employees from this work activity to the

¹⁰¹⁴ Ex. PAO-07 at 2; Cal Advocates OB at 187 and 190.

¹⁰¹⁵ TURN OB at 140.

Emergency Management BPE, (2) an increase in staff to support the Information Technology/Disaster Recovery program, and (3) a slightly lower projection for non-labor costs.

We find reasonable and adopt SCE's uncontested TY O&M forecast of \$1.315 million for Planning, Continuity, and Governance.

20.2. All Hazards Assessment, Mitigation, and Analytics

The objectives of SCE's All Hazards Assessment, Mitigation, and Analytic activities are to identify and analyze SCE's exposure to natural and man-made hazards and their potential impacts; develop and coordinate efforts to mitigate the impacts using industry standards or best practices; and improve analytics and technology to support business resiliency functions. SCE's All Hazards Assessment, Mitigation, and Analytics activities are broken into the following four programs:

- Seismic Assessment and Mitigation Program: Formed in 2015 to centralize all seismic related work company-wide, and to provide consistency in approach, prioritization of work, and reporting. The program works with multiple business lines across the company in executing seismic assessment and mitigation projects for electric infrastructure, non-electric facilities, generation, and IT/telecommunications infrastructure.
- Climate Adaptation and Severe Weather Program: Formed in 2018 to develop a consistent, company-wide approach to analyze climate hazards, and identify and implement adaptive measures. Program activities also include analyzing and assessing climate change impacts and related climate science data.
- Targeted Hazard Analysis: Initiated in 2019 to mitigate emerging hazards that arise from year to year, such as extreme rain that can lead to flooding or mudslides. Mitigation actions are informed through an annual

targeted hazard analysis using seasonal weather and climate outlooks that may forecast unusual weather patterns.

- Analytics and Technology Integration: Implements technological solutions to support SCE's business continuation and emergency management efforts, including a storm damage prediction model, business continuity planning, emergency management tools, and Geographical Information Systems (GIS) for mapping and analysis.¹⁰¹⁶

20.2.1. All Hazards, Assessment, Mitigation, and Analytics O&M

SCE's TY O&M forecast for All Hazards Assessment, Mitigation, and Analytics is \$3.983 million.¹⁰¹⁷ SCE's forecast is based on 2018 recorded costs (\$2.271 million) plus upward adjustments to reflect additional planned activities during 2021. This includes (\$1.658 million) in non-labor costs to relocate employees during seismic retrofit projects, conduct a vulnerability assessment, and perform a hazard analysis based on emergent threats.¹⁰¹⁸

Cal Advocates recommends \$3.779 million for the TY O&M forecast, a \$0.204 million reduction from SCE's request. While Cal Advocates does not oppose SCE's labor forecast of \$0.479 million, Cal Advocates recommends a reduction of \$0.204 million from SCE's forecast of non-labor costs in the TY on the basis that "SCE had significant fluctuations from 2014-2018 to forecasted TY 2021. It varied from a low of \$0.275 million in 2015 to a high of \$1.846 million in 2018 to a forecast of \$3.504 million in 2021."¹⁰¹⁹ Cal Advocates proposes using

¹⁰¹⁶ Ex. SCE-04, Vol. 1 at 16-18.

¹⁰¹⁷ Ex. SCE-15, Vol. 1 at 2, Table I-1.

¹⁰¹⁸ Ex. SCE-04, Vol. 1 WP at 8-14.

¹⁰¹⁹ Ex. PAO-07 at 18-19.

the 2019 forecast of non-labor expenses for the Test Year 2021 to smooth out the various fluctuations.¹⁰²⁰

In response, SCE asserts that Cal Advocates' reference to "various fluctuations" does not account for the evolution of All Hazards Assessment, Mitigation and Analytics activities over the years, which has included steady increases in costs since 2016; that the additional increase in non-labor costs corresponds with the inclusion of the Climate Adaptation and Severe Weather program in 2018; and that Cal Advocates never contests the merit or reasonableness of SCE's itemized forecast of expenses during the 2021 TY.¹⁰²¹

Beyond claiming that SCE's non-labor costs have fluctuated over the past eight years, Cal Advocates does not explain why 2019 forecast data is an appropriate basis to smooth out past fluctuations, nor does Cal Advocates evaluate what SCE needs to accomplish the specific projects identified in SCE's workpapers. In contrast, we find SCE's itemized non-labor forecast to be well supported, reasonable, and more indicative of the level of expenses SCE is likely to incur in 2021. We also find reasonable SCE's uncontested labor forecast of \$0.479 million. Taken together, we approve SCE's full TY O&M forecast \$3.983 million for All Hazards Assessment, Mitigation, and Analytics.

20.2.2. All Hazards, Assessment, Mitigation, and Analytics Capital

SCE's 2019-2021 capital expenditure forecast includes \$136.481 million for the Seismic Assessment and Mitigation Program and \$1.560 million for the Climate Adaptation and Severe Weather Program.¹⁰²² The capital forecast for the

¹⁰²⁰ *Ibid.*

¹⁰²¹ Ex. SCE-15, Vol. 1 at 5-6.

¹⁰²² Ex. SCE-15, Vol. 1 at 3, Table I-2.

Seismic Assessment and Mitigation Program includes: (1) assessment of SCE's electric infrastructure, non-electric facilities, generation infrastructure and telecommunications/IT infrastructure to identify what seismic mitigations are needed, and (2) implementation of the necessary retrofits and improvements. The 2019-2021 capital expenditure forecast for electric infrastructure includes the following sub-activities: Transmission Substation/Line/Tower Assessment; Distribution Substation Assessment; Transmission Substation Mitigation; Transmission Lines/Tower Mitigation; and Distribution Substation Mitigation. The capital forecast for Climate Adaptation and Severe Weather Program includes substation flood prevention measures as well as the installation of monitoring devices to better evaluate sea level rise, changing landslide potential due to changes in precipitation, and the impact of urban heat areas.¹⁰²³

SCE began its seismic mitigation work in the 2018 GRC, and states it expects seismic work to be the subject of future rate cases.¹⁰²⁴ Between 2019-2023, SCE forecasts expenditures of \$111.108 million to complete 58 transmission substation assessment and mitigation projects; \$41.1 million for detailed engineering assessments of transmission buildings and retrofits of 16 buildings known as Mechanical Electrical Equipment Rooms (MEERs);¹⁰²⁵ \$18 million to assess approximately 9,000 transmission towers in earthquake and landslide prone areas and to mitigate approximately 18 towers; \$32.5 million for the

¹⁰²³ Ex. SCE-04, Vol. 1 at 25-29.

¹⁰²⁴ *Id.* at 25-26.

¹⁰²⁵ MEERs house critical IT and electrical control infrastructure to operate a substation and support critical power delivery functionality to distribution substations following an earthquake. (*Id.* at 30.) SCE's 2021-2023 forecast includes sixteen MEER projects, five of which are to be completed in 2021. MEER project costs are embedded into SCE's forecasts for both electric and non-electric facilities. (Ex. PAO-07 at 29; Cal Advocates OB at 188-189.)

assessment of up to 200 distribution substations and mitigation of ten distribution substations; \$41 million to assess and retrofit 27 non-electric facilities (primarily offices and operational buildings supporting power delivery); and \$4 million for continuing assessment and mitigation work at generation facilities.¹⁰²⁶

SCE's forecasts for the Seismic Assessment and Mitigation Program and Climate Adaptation and Severe Weather Program are based on historic costs for similar work as well as estimates from third-party engineering firms, consultants, and vendors.¹⁰²⁷

Cal Advocates does not object to SCE's 2019-2021 forecasts for Transmission Substation Line Tower Assessments, Distribution Substation Assessment, Transmission Line Tower Mitigation, Distribution Substation Mitigation, Non-Electric Facilities, Generation Infrastructure, Climate Adaptation and Severe Weather categories.¹⁰²⁸ While Cal Advocates accepts SCE's 2019 and 2020 forecasts for the Transmission Substation Mitigation category, Cal Advocates recommends a reduction of \$5.637 million to SCE's 2021 forecast (*i.e.*, from \$21 million to \$15.363 million). Cal Advocates states that SCE's methodology to derive cost estimates for the MEER retrofits was based on a third-party engineering estimate that was then increased by 240 percent to derive SCE's forecast. Cal Advocates also observes that SCE applied a 35 percent contingency at least four times throughout its supporting workpaper, which

¹⁰²⁶ SCE's MEER project costs are embedded into two different cost estimates; therefore totals exceed SCE's Electric Infrastructure forecast by sub-category. Figures also do not include 2019 recorded. (Ex. SCE-04, Vol. 1E at 29-21; Ex. SCE-04, Vol. 1E at 29-21.)

¹⁰²⁷ *Id.* at 28-29 and 34-35.

¹⁰²⁸ Ex. PAO-7 at 28-31.

accounted for most of the 240 percent difference between the SCE estimate and the third-party engineering firm estimate. Cal Advocates opposes the use of multiple 35 percent contingency increases in the MEER projects estimate and recommends the removal of the 240 percent increase.¹⁰²⁹

TURN recommends a combined reduction of \$26.511 million to SCE's 2019-2023 capital expenditure forecast for the Seismic Assessment and Mitigation Program. TURN's recommendation is premised on two main points: first, similar to Cal Advocates' position, TURN argues that SCE inappropriately applied contingencies in its forecasts, including a 35 percent contingency rate for the Transmission Substation Mitigation category (\$14.4 million over 2019-2023) as well as a 1.5 percent contingency rate for the Non-Electric Facilities category (\$1.366 million over 2019-2023).¹⁰³⁰ TURN asserts that contingency costs are not reasonable in the context of cost-of-service forecast ratemaking, where the costs requested in this GRC will be charged to ratepayers regardless of the amount actually spent; that contingency costs are highly speculative, and cannot be attributed to specific activities; that SCE already accounted for cost uncertainties by significantly increasing the cost estimates provided by a third-party engineering firm; and that the proposed contingency rate of 35 percent is particularly high. TURN also observes that the Commission declined SCE's request for software project contingency costs in SCE's last GRC.¹⁰³¹

Second, TURN takes issue with one of the projects SCE included in the calculation of the average cost per square foot for retrofitting non-electrical facilities. TURN highlights that the forecast cost for this one project has a

¹⁰²⁹ *Ibid*; Cal Advocates OB at 188-189.

¹⁰³⁰ Ex. TURN-10 at 2.

¹⁰³¹ *Id.* at 3-7; TURN OB at 140-145.

significantly higher cost per square foot than any of the remaining projects, increasing the average cost per square foot from \$28.66 to \$43.42, which SCE rounds up to \$45 per square foot. TURN also asserts it is inappropriate to use this forecasted amount in the average, since all other project costs included in SCE's calculation are known and measurable recorded costs. Finally, TURN highlights that the actual cost of the forecasted project was only \$332,542 as of March 2020, compared to the \$11 million SCE forecasts to complete the project. For these reasons TURN recommends the average be calculated without this forecasted project, reducing the \$45 cost per square foot to \$28.66 per square foot, with a corresponding reduction of approximately \$10.745 million to SCE's Non-Electric Facilities forecast.¹⁰³²

In response to Cal Advocates, SCE states the increases reflect several cost categories attributed to the unique aspects of working conditions in high voltage substations and which are not captured in the third-party estimate. For example, SCE states the third-party estimate failed to account for costs arising from the limited pool of vendors qualified to work in energized substations, and underestimated costs for temporary roofing and protection of sensitive electrical relaying equipment and overhead and contractor costs. SCE also asserts the unique and complex nature and scope of these projects may require the structural retrofitting of MEER buildings when unforeseen field conditions arise.

In response to TURN, SCE asserts the application of a contingency factor is an industry standard practice, and that a higher contingency factor (*i.e.*, 35 percent) was applied to the MEER seismic mitigation work to account for the higher level of risk involved. Further, in contrast to other categories of seismic

¹⁰³² *Ibid.*

mitigation work which SCE has previously undertaken, SCE states seismic mitigation projects at transmission substations require structural retrofitting of MEERs, which increases the likelihood of unforeseen field conditions during the construction phase. In response to TURN's argument that granting contingency allowances disincentivizes SCE to remain within the project budget, SCE states project forecasts were made in the planning phase before the budgeting process, and that contingency allowances will ultimately be incorporated into other construction line items as the project moves forward.

Concerning the calculation of the average cost per square foot for retrofitting non-electrical facilities, while SCE primarily relied on historical expenditures for the calculation, SCE states it plans to perform retrofits on non-electric facilities which are larger in size and scope than past seismic mitigation projects. SCE further explains that preliminary cost estimates for planned work at larger facilities (179,941 to 244,449 square feet) reflect an average cost per square foot of \$59. Given that SCE plans to retrofit larger non-electrical facilities from 2019-2023, and since there are no historic expenditures for a project of this size and scope, SCE asserts it reasonably included the cost estimate for an ongoing project at a larger facility.¹⁰³³

Parties generally do not dispute the need and justification for SCE's planned seismic mitigation projects; rather, the main point of dispute concerns SCE's cost estimates for these projects. We agree SCE's proposed seismic mitigation projects are reasonable in scope and necessary to address the safety and reliability impacts related to seismic risk across SCE's facilities.

¹⁰³³ Ex. SCE-15, Vol. 1 at 11-12.

The Commission determined in SCE's 2018 GRC that the contingency amounts included in SCE's capitalized software project forecasts were not recoverable as a forecast item.¹⁰³⁴ While the nature and purpose of seismic retrofitting is distinct from capitalized software projects, the underlying rationale SCE provides to justify the application of a contingency factor in both forecasts remains the same: mainly, that the application of a contingency factor is an industry standard practice used to account for unknown or unforeseen conditions.¹⁰³⁵ As explained in D.19-05-020, budgeting for contingencies is not necessarily appropriate in the context of a general rate case, where the utility must demonstrate the reasonableness of every dollar in its forecast revenue requirement. Since contingency allowances are, by SCE's own admission, intended to cover "unforeseen conditions," these amounts are also unpredictable, and therefore, we find that SCE has not established these costs to be reasonable. As stated in D.19-05-020, disallowing the 35 percent and 1.5 percent contingencies should motivate SCE to remain within its forecast budgets for these projects.¹⁰³⁶ If additional funds become necessary SCE may seek to establish that necessity in the next GRC.

SCE also adjusts its forecast for the structural retrofitting of MEER buildings to account for certain costs that were excluded from the third-party engineering estimate. It is not clear why SCE did not hire an engineering firm that was more familiar with physical environments presented by large substations to begin with, rather than producing an incomplete estimate that required adjustments. However, a significant difference between the third-party

¹⁰³⁴ D.19-05-020 at 150-153.

¹⁰³⁵ See D.19-05-020 at 149-150; also, Ex. SCE-15, Vol. 1 at 12.

¹⁰³⁶ D.19-05-020 at 152.

engineering estimate and SCE's estimate is the application of the 35 percent contingency factor, which we decline for the reasons provided above. Other noteworthy adjustments include risk and vendor availability, project support labor, and overhead.¹⁰³⁷ We have considered SCE's rationale for these adjustments, as well as the level of adjustments made, and generally find the amounts to be reasonable. SCE is directed to track how closely actual recorded project costs align with its 2019-2023 cost estimate for MEER projects and include this information with any seismic funding requests in the next GRC.

Lastly, we find that SCE has not sufficiently justified the inclusion of the larger office building in the cost per square foot calculation of non-electric facilities. There is not a consistent, direct relationship between building size and the price per square foot even for SCE's previously completed retrofit projects,¹⁰³⁸ and it is not clear, based on the record before us, that the large \$11 million office building is representative of the retrofit projects that SCE plans to complete during 2019-2023. The fact that this larger office building is still under construction adds further uncertainty regarding the accuracy of SCE's forecast. For these reasons, we adopt TURN's proposal to recalculate the average without this \$11 million project, which reduces the cost per square foot calculation to \$28.66 per square foot and reduces SCE's forecast by approximately \$10.745 million. Because SCE lacks historic expenditures for projects of this size, we authorize SCE to establish a memorandum account to track non-electric

¹⁰³⁷ Ex. SCE-15, Vol. 1, Attachment A at A-11.

¹⁰³⁸ For example, there does not appear to be a direct relationship between the size and project cost for the garage and two other office build estimates used in SCE's Non-Electric Facilities Cost Per Square Foot Calculation. (See Ex. TURN-10 at 5.)

facilities seismic retrofit costs with the opportunity to seek recovery for any costs above the amount authorized in this decision in SCE's next GRC.

SCE's remaining forecasts for the Seismic Assessment and Mitigation Program and the Climate Adaptation and Severe Weather Program are uncontested. We find reasonable and adopt these uncontested forecasts. Removing the contingencies for Transmission Substation Mitigation (-\$14.4 million) and for Non-Electric Facilities (-\$1.366M), and revising the cost per sq. ft. to \$28.66 (-\$10.745 million), results in a total approved 2019-2021 capital expenditure budget of \$120.818 million for the Seismic Assessment and Mitigation Program and \$1.560 million for the Climate Adaptation and Severe Weather Program.

21. Emergency Management

SCE's Emergency Management BPE activities include: (1) Training, Drills, and Exercises; (2) Emergency Preparedness & Response; and (3) Storm Response. Requested funding supports SCE's continuing efforts to implement U.S. Department of Homeland Security national standards, such as the National Response Framework, the National Incident Management System (NIMS) and the Incident Command System (ICS), as well as to address the complexities in coordinating effective response activities with local, state, and federal partners during emergency events.

For Emergency Management, SCE forecasts combined 2021 TY O&M expenses of \$20.833 million and combined 2019-2021 capital expenditures of \$177.138 million.¹⁰³⁹ SCE's TY O&M forecast is comprised of training, drills and

¹⁰³⁹ Includes recorded 2019 capital expenditures of \$75.713 million. (Ex. SCE-15, Vol. 2E at 2; SCE OB at 192-193.) We note that SCE presents a higher capital forecast for 2020-2021 in Ex. SCE-04, Vol. 2E3; however, this exhibit does not accurately reflect SCE's recorded 2019 expenditures. Therefore, the totals reported are what SCE included in its opening brief.

exercises, emergency preparedness response, and storm response, and is based on a combination of 2018 recorded costs plus adjustments¹⁰⁴⁰ and a five-year average of recorded storm response costs (2014-2018). SCE's capital expenditure forecast includes costs associated with replacing electrical facilities, structures, or equipment damaged during storm events,¹⁰⁴¹ and is based on 2019 recorded costs plus a five-year average of recorded costs (2014-2018) for 2020 and 2021.

We find reasonable and approve SCE's uncontested combined TY O&M forecast of \$20.833 million for Emergency Management. Regarding SCE's capital expenditure forecast, while we agree it is appropriate for SCE's capital expenditure forecast for Emergency Management to be based on a five-year average of recorded (2014-2018) expenditures since storm events can vary significantly from year to year and are driven by factors outside of SCE's control, SCE made several adjustments to its capital expenditure forecast throughout this proceeding. SCE initially forecast \$46.534 million and \$47.953 million in Emergency Management capital expenditures for 2020-2021.¹⁰⁴² Without explanation provided, these amounts were subsequently adjusted to \$49.951 million and \$51.174 million in 2020-2021,¹⁰⁴³ then adjusted again to

¹⁰⁴⁰ Adjustments reflect a net increase of approximately \$0.500 million over 2018 recorded costs and are attributed to an increase in non-labor for training drills and exercises; additional emergency management staffing (which is partially offset through the transfer of three meteorologists); and an increase in non-labor emergency response tools. (Ex. SCE-04, Vol. 2 at 15-16 and 24-25.)

¹⁰⁴¹ When storm events are declared as states of emergency by the Governor of California, any associated storm-related expenses that exceed Commission-authorized amounts are eligible for recovery through a Catastrophic Events Memorandum Account filing. (Ex. SCE-04, Vol. 2 at 26.)

¹⁰⁴² Ex. SCE-04, Vol. 2 Table I-4 at 5.

¹⁰⁴³ Ex. SCE-04, Vol. 2E Table II-5 at 29; SCE-15, Vol. 2 Table I-2 at 2; SCE OB at 192-193.

\$56.401 million and \$58.118 million in 2020-2021.¹⁰⁴⁴ SCE’s initial forecast appears consistent with the use of a five-year average of recorded expenditures from 2014-2018, and we decline to adopt further adjustments to SCE’s initial forecast without justification or clear ties to SCE’s purported forecast methodology. Incorporating SCE’s recorded 2019 capital expenditures (\$75.713 million) results in a total authorized 2019-2021 capital expenditure amount of \$170.2 million.

22. Cybersecurity

The Cybersecurity BPE encompasses Cybersecurity and IT Compliance activities and infrastructure for SCE’s broader Grid Modernization effort.

22.1. Cybersecurity O&M

SCE forecasts TY O&M expenses of \$38.582 million for the Cybersecurity BPE. This forecast includes work for the following activities:¹⁰⁴⁵

Activity	TY Forecast (\$000)
Cybersecurity Delivery and IT Compliance (C&C)	32,232
Grid Modernization Cybersecurity	617
Software License and Maintenance	5,733
Total	38,582

Cal Advocates recommends a TY forecast of \$27.278 million.¹⁰⁴⁶

Cal Advocates recommends a reduction to the C&C forecast but does not oppose the other two forecasts.

¹⁰⁴⁴ Ex. SCE-04, Vol. 2E2 Table II-5 at 29; Ex. SCE-04, Vol. 2E3 Table II-5 at 29.

¹⁰⁴⁵ Ex. SCE-15, Vol. 3 at 3, Table I-3.

¹⁰⁴⁶ Cal Advocates OB at 194.

We find SCE has provided adequate justification for the unopposed forecasts.¹⁰⁴⁷ The Grid Modernization Cybersecurity forecast is generally consistent with 2018 recorded costs excluding the impact of an accounting change in 2018.¹⁰⁴⁸ The Software License and Maintenance forecast is based on the costs for an itemized list of software and licenses.¹⁰⁴⁹ We find the forecasts to be reasonable and adopt them.

22.1.1. Cybersecurity Delivery and IT Compliance

SCE's C&C activity is divided into five program areas:¹⁰⁵⁰

- (1) Perimeter Defense represents SCE's outer layer of cybersecurity protection, which uses technologies (*e.g.*, firewalls and intrusion detection systems) and related processes, hardware, and software to prevent, absorb, or detect attacks and reduce the risk to critical back end systems.
- (2) Interior Defense secures SCE's internal business systems from unauthorized users, devices, and software.
- (3) Data Protection safeguards the computing environment housing SCE's core information.
- (4) SCADA Cybersecurity implements risk reduction methods tailored for SCE's SCADA systems, which remotely control and monitor the electric grid.
- (5) NERC CIP Compliance involves the ongoing implementation of systems and processes to comply with NERC CIP cybersecurity requirements.

¹⁰⁴⁷ Ex. SCE-04, Vol. 3 at 30-36, 40-46.

¹⁰⁴⁸ *Id.* at 36.

¹⁰⁴⁹ *Id.* at 46.

¹⁰⁵⁰ *Id.* at 10, 13-15.

SCE forecasts TY O&M expenses of \$32.232 million for C&C, consisting of \$19.982 million for labor and \$12.250 million for non-labor. Cal Advocates recommends reductions to both the labor and non-labor forecasts.

22.1.1.1. Labor Costs

SCE forecasts TY C&C labor expenses of \$19.982 million. SCE's C&C labor expenses steadily declined from 2016-2018; SCE uses the 2018 recorded labor costs (\$8.796 million) as the initial basis of its TY forecast based on Commission guidance that the last recorded year is an appropriate forecast method when recorded costs exhibit a downward trend for three or more years.¹⁰⁵¹ SCE then makes the following adjustments to the 2018 recorded labor costs to reflect the filling of positions that were vacant in 2018 and the addition of staff to support expanded C&C activities.¹⁰⁵²

- A \$1.9 million increase for additional staffing to support existing C&C cyber defense capabilities;
- A \$0.9 million increase to support commencement of the Identity Governance & Administration Management (IGAM) platform, which will replace the legacy Identity & Access Management (IAM) infrastructure;¹⁰⁵³
- A \$1.92 million increase to support Information Technology/ Operational Technology (IT/OT) integration efforts, including assisting substations with addressing and expanding SCE's cybersecurity policies and standards;
- A \$1.89 million increase to support Foundational Tools, which are new cyber tools and technologies to strengthen cyber defense posture in the grid environment;

¹⁰⁵¹ *Id.* at 21.

¹⁰⁵² *Id.* at 21-24.

¹⁰⁵³ The IGAM platform is intended to mitigate security risks as SCE's traditional IT infrastructure expands into cloud and Software-as-a-Service offerings. (*Id.* at 22.)

- A \$0.9 million increase to support cybersecurity enhancement of SCE Tech Labs;
- A \$0.9 million increase to support National Institute of Standards and Technology (NIST) Standards Gap assessment and remediation; and
- A \$0.3 million increase to support IT Compliance/Disaster Recovery activities.

Cal Advocates recommends a TY labor forecast of \$14.853 million.

Cal Advocates uses SCE's 2019 labor forecast (\$11.063 million) as the basis for its forecast and includes SCE's proposed adjustments of \$1.9 million for additional staffing to support existing C&C capabilities and \$1.89 million to support Foundational Tools.¹⁰⁵⁴ Cal Advocates opposes the remainder of the adjustments proposed by SCE. Cal Advocates argues these adjustments are not justified because:¹⁰⁵⁵

- SCE will be shifting current IAM staff to support the IGAM platform;
- SCE plans to train current staff to support IT/OT integration efforts;
- Use of the 2019 forecast accounts for additional staff that SCE would have hired in 2019 for SCE's Tech Labs;
- The NIST Framework is voluntary guidance based on existing standards, guidelines, and practices; and
- IT Compliance and Business Resiliency personnel already have strong communication and bi-weekly team meetings concerning disaster recovery activities.

We find SCE has failed to adequately justify its requested forecast. SCE states its labor forecast is based on 2018 recorded costs plus adjustments. SCE's

¹⁰⁵⁴ Cal Advocates OB at 194-195.

¹⁰⁵⁵ *Ibid.*

2018 recorded labor costs total \$8.796 million.¹⁰⁵⁶ The additional adjustments requested by SCE in its testimony total \$8.71 million.¹⁰⁵⁷ Based on SCE's explanation of its forecast, the forecast should total \$17.506 million, not \$19.982 million as SCE forecasts. It is unclear what accounts for the additional \$2.476 million included in SCE's forecast.

Moreover, although SCE asserts its forecast is supported by its workpapers, the cost estimates set forth in the workpapers do not correspond to SCE's requested forecast.¹⁰⁵⁸ SCE's workpapers also do not provide sufficient detail regarding the scope of work that would justify the additional labor requested.

Furthermore, it is unclear why increases to the extent proposed by SCE would be justified in light of the fact that SCE will be shifting current staff to support the new programs, and the fact that SCE's capital budget also includes labor costs for implementation of IGAM, IT/OT integration, Foundational Tools, and Labs. As discussed below, we approve SCE's requested Cybersecurity capital expenditures, which include capitalized costs for labor.

Instead, we find Cal Advocates' proposed forecast to be reasonable. The forecast is an increase of \$6.057 million, or 69 percent, over 2018 recorded costs. SCE explains that several vacant positions remained unfilled in 2018 resulting in a reduced forecast. Using the 2019 forecast as the basis for the TY forecast accounts for the filling of additional positions beyond 2018 levels.

Cal Advocates' proposed forecast also includes adjustments of approximately \$3.79 million for additional support of C&C activities and Foundational Tools.

¹⁰⁵⁶ Ex. SCE-04, Vol. 3 at 21, Table II-6.

¹⁰⁵⁷ *Id.* at 21-24.

¹⁰⁵⁸ Ex. SCE-15, Vol. 3, Appendix B at B-1.

Although SCE justifies the need for some increase to 2018 recorded costs, it fails to justify an increase beyond the already sizeable increase recommended by Cal Advocates. Therefore, we adopt Cal Advocates' proposed TY labor forecast of \$14.853 million.

22.1.1.2. Non-Labor Costs

SCE forecasts TY C&C non-labor expenses of \$12.250 million. SCE's C&C non-labor expense fluctuated from 2014 to 2018. SCE states the higher level of consultant support starting in 2018 is expected to continue.¹⁰⁵⁹ SCE's TY forecast is based on an itemized forecast, which SCE argues is warranted due to several new cybersecurity initiatives planned for TY 2021.¹⁰⁶⁰

Cal Advocates recommends a forecast of \$6.075 million based on 2018 recorded costs.¹⁰⁶¹ Cal Advocates notes SCE's TY forecast is double to quadruple the recorded costs in 2014 through 2018, which ranged from a low of \$2.804 million to a high of \$6.075 million. Cal Advocates argues SCE has not adequately supported or shown the need for such a significant increase in non-labor costs.

SCE fails to justify its requested increase to non-labor expense for outside consultants in light of the increases to labor expense and capitalized labor expense, including both vendor and SCE labor for implementation of new cybersecurity initiatives, which we approve in this decision. Moreover, the itemized forecast provided by SCE in its workpapers, which SCE cites in support

¹⁰⁵⁹ SCE recorded 2018 non-labor expense of \$6.075 million. SCE states the \$3.3 million increase between 2017 and 2018 recorded costs was due to an internal accounting change that SCE does not reflect in the TY 2021 forecast. (Ex. SCE-04, Vol. 3 at 20.)

¹⁰⁶⁰ *Id.* at 24-25.

¹⁰⁶¹ Cal Advocates OB at 195.

of its forecast, does not correspond to the itemized forecast requested in its testimony.¹⁰⁶²

We find reasonable and adopt Cal Advocates' recommended forecast based on 2018 recorded costs. SCE explains that \$3.3 million of these recorded costs are attributable to an internal accounting change. Therefore, use of the 2018 recorded costs still provides additional funding beyond SCE's 2018 base costs to support SCE's new cybersecurity initiatives.

22.2. Cybersecurity Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast Cybersecurity capital expenditures (nominal, \$000).¹⁰⁶³

Capital Expenditures		2019	2020	2021
Cybersecurity	NERC CIP	2,793	2,478	5,478
Delivery and IT	Perimeter Defense	26,476	19,452	37,577
Compliance (C&C)	Data Protection	6,203	7,268	8,571
	Interior Defense	7,620	8,103	8,107
	SCADA Cybersecurity	1,610	2,549	2,551
Grid Modernization Cybersecurity		26,136	24,542	45,245
Total		70,837	64,392	107,530

Cal Advocates recommends adoption of SCE's 2019 forecast costs as opposed to the recorded 2019 costs.¹⁰⁶⁴ Cal Advocates also opposes the 2021 forecasts for Perimeter Defense and Grid Modernization Cybersecurity. Cal

¹⁰⁶² Ex. SCE-04, Vol. 3 at 25, Table II-7; Ex. SCE-15, Vol. 3, Appendix B at B-2.

¹⁰⁶³ Ex. SCE-15, Vol. 3E at 13, Table II-7. The C&C program areas are described in the Cybersecurity O&M Section, above.

¹⁰⁶⁴ Cal Advocates OB 192-193.

Advocates does not oppose SCE's 2020 forecasts¹⁰⁶⁵ or the remainder of SCE's 2021 forecasts.

We find SCE has provided adequate justification for the unopposed forecasts.¹⁰⁶⁶ SCE primarily derived its cost estimates from vendor quotes for hardware purchases and five-year software licensing, and the labor needed for the planned scope of the initiatives.¹⁰⁶⁷ We find the unopposed 2020-2021 forecasts to be reasonable and adopt them. The contested forecasts are discussed below.

22.2.1. 2019 Costs

SCE initially forecast 2019 Cybersecurity capital expenditures totaling \$61.702 million.¹⁰⁶⁸ SCE's rebuttal testimony requests authorization of the 2019 recorded expenditures totaling \$70.837 million.¹⁰⁶⁹ SCE explains its recorded 2019 capital expenditures were \$9.134 million above the forecast primarily due to identified critical vulnerabilities with tech labs and perimeter infrastructure that required immediate remediation.¹⁰⁷⁰

Cal Advocates states it could not properly analyze SCE's recorded 2019 costs, and therefore, recommends adoption of the 2019 forecast.¹⁰⁷¹

¹⁰⁶⁵ Cal Advocates presents SCE's 2020 forecast as \$64.949 million rather than SCE's most updated forecast of \$64.392 million presented in errata to SCE's rebuttal testimony. (Ex. SCE-15, Vol. 3E at 13, Table II-7.)

¹⁰⁶⁶ Ex. SCE-04, Vol. 3 at 13-15, 26-30.

¹⁰⁶⁷ *Id.* at 26-30.

¹⁰⁶⁸ *Id.* at 3.

¹⁰⁶⁹ Ex. SCE-15, Vol 3E at 13, Table II-7.

¹⁰⁷⁰ *Id.* at 11.

¹⁰⁷¹ Cal Advocates OB at 192-193.

We see no reason to adopt the 2019 forecast when the actual 2019 expenditures are known and part of the record. Consistent with our treatment of 2019 capital expenditures for other BPEs, we find reasonable and authorize the 2019 recorded capital expenditures.

22.2.2. Perimeter Defense

SCE's 2021 forecast capital expenditures of \$37.577 million for Perimeter Defense consist of the following: (1) Perimeter Defense (\$13.6 million); (2) IT/OT (\$13.5 million); (3) Foundational Tools (\$1.5 million); (4) IGAM (\$6.5 million); and (5) Labs (\$2.5 million). SCE's forecast is based on the itemized costs for hardware purchases, five-year software licensing, and capitalized labor for implementation activities.¹⁰⁷²

Cal Advocates recommends a 2021 forecast of \$17.851 million based on a two-year average of SCE's 2019 and 2020 forecast costs.¹⁰⁷³ Cal Advocates argues Perimeter Defense has fluctuated significantly over the years, with a low of \$5.687 million in 2016 to a high of \$18.158 million in 2017.

Cal Advocates fails to justify using an average of SCE's 2019 and 2020 forecasts to develop the TY forecast. SCE explains that its capital forecast is risk-based and itemized based on planned enhancements and upgrades to SCE's computing environment for each year.¹⁰⁷⁴ SCE details the growing threat of cyberattacks as attacks continually increase in frequency and sophistication.¹⁰⁷⁵ SCE describes the incremental activities it forecasts for 2021 related to IGAM

¹⁰⁷² Ex. SCE-04, Vol. 3 at 28-30.

¹⁰⁷³ Cal Advocates OB at 196.

¹⁰⁷⁴ Ex. SCE-15, Vol. 3 at 14.

¹⁰⁷⁵ Ex. SCE-04, Vol. 3 at 15-16.

Phases 2 and 3, IT/OT integration, Foundational Tools, and Labs.¹⁰⁷⁶ Cal Advocates disputes SCE's forecast costs but does not dispute the incremental scope of work that SCE forecasts for 2021. SCE's 2019 and 2020 forecasts do not include any funding for IGAM, IT/OT integration, or Foundational Tools, and therefore, do not account for the level of expenditures needed for these projects planned for 2021.¹⁰⁷⁷

We find SCE has provided adequate justification for its 2021 forecast in light of the incremental work it forecasts for that year. Therefore, we approve 2021 capital expenditures of \$37.577 million for Perimeter Defense.

22.2.3. Grid Modernization Cybersecurity

SCE's Grid Modernization Cybersecurity program focuses on addressing the security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program. SCE forecasts 2021 Grid Modernization Cybersecurity capital expenditures of \$45.245 million. The capital forecast includes costs for SCE employees, supplemental workers, consultants, software, hardware, and selected vendor costs.¹⁰⁷⁸ Starting in 2021, SCE will be deploying and configuring security and data protection capabilities related to multiple grid modernization workstreams, including Field Area Network (FAN), Common Substation Platform (CSP), Wide Area Network (WAN), and Grid Management System (GMS).¹⁰⁷⁹ SCE argues the implementation schedules of these workstreams warrant the higher level of

¹⁰⁷⁶ *Id.* at 13, 22-23, 28-30.

¹⁰⁷⁷ *Id.* at 27, Table II-9.

¹⁰⁷⁸ *Id.* at 37; Ex. SCE-15, Vol. 3, Appendix B at B-6.

¹⁰⁷⁹ Ex. SCE-04, Vol. 3 at 37-40.

cybersecurity expenditures for hardware, software, and related service costs during 2021.

Cal Advocates recommends a 2021 Grid Modernization Cybersecurity capital expenditure forecast of \$25.326 million based on a two-year average of SCE's 2019 recorded and 2020 forecast costs.¹⁰⁸⁰ Cal Advocates notes SCE began recording costs for this category in 2016 and SCE's forecast is more than double the highest costs recorded in this category in 2018. Cal Advocates also points out that SCE's forecast is based on vendor quotes as opposed to signed contracts.

We find SCE has provided adequate justification for its 2021 forecast. SCE details the need for additional cybersecurity activities in 2021 to support SCE's grid modernization workstreams.¹⁰⁸¹ We also find the vendor quotes provide a reasonable basis for the cost forecast.¹⁰⁸² Cal Advocates disputes SCE's forecast costs but does not dispute the incremental scope of work that SCE forecasts for 2021. Cal Advocates' recommended TY forecast based on SCE's 2019 recorded and 2020 forecast costs would not account for the additional cybersecurity work projected for 2021. We find SCE's 2021 forecast to be adequately justified and reasonable, and therefore, approve SCE's requested 2021 Grid Modernization Cybersecurity capital expenditures of \$45.245 million.

23. Physical Security

The Physical Security BPE addresses the physical protection of SCE's workforce, customers, facilities, and infrastructure from threats, intrusions, attacks, theft, and property damage.

¹⁰⁸⁰ Cal Advocates OB at 196.

¹⁰⁸¹ Ex. SCE-04, Vol. 3 at 31-33, 37-40.

¹⁰⁸² See Ex. SCE-15, Vol. 3, Appendix B at B-6.

23.1. Physical Security O&M

SCE forecasts TY O&M expenses of \$23.588 million for the Physical Security BPE, consisting of \$6.189 million in labor expense and \$17.399 in non-labor expense. SCE's forecast is based on an itemized forecast using last year recorded (2018) costs plus incremental changes addressing increased labor costs, as SCE experienced a high volume of vacancies in 2018 and lower levels of non-labor costs primarily due to reprioritization of services across SCE's service territory.¹⁰⁸³

The O&M forecast includes two activities: (1) Security Technology, Operations and Maintenance (\$6.189 million labor, \$17.186 million non-labor); and (2) Workforce Protection and Insider Threat Programs (\$0.000 million labor, \$0.213 million non-labor).¹⁰⁸⁴

Security Technology, Operations and Maintenance includes two sub-activities: (1) Project Management Office, which manages and prioritizes physical security projects; and (2) Break-fix and Preventative Maintenance, which monitors and repairs security systems and equipment in use at SCE.

The Workforce Protection and Insider Threat program includes: (1) security officer services; (2) centralized alarm monitoring and call/dispatch via the Edison Security Operations Center; (3) badging office; (4) background investigations; (5) Insider Threat program; and (6) governance and compliance oversight of security programs.

Cal Advocates recommends adjustments to SCE's non-labor forecast for Security Technology, Operations and Maintenance. Cal Advocates argues SCE's

¹⁰⁸³ Ex. SCE-04, Vol. 4 at 19-20.

¹⁰⁸⁴ Ex. SCE-15, Vol. 4 at 4, Table II-4; Ex. PAO-07 at 25.

non-labor costs for this activity have widely fluctuated from a low of \$1.859 million in 2014 to a high of \$20.828 million in 2017.¹⁰⁸⁵ Therefore, Cal Advocates recommends using a two-year average of recorded 2018 and forecast 2019 costs to determine the TY non-labor forecast. Cal Advocates' recommendation results in a TY non-labor forecast of \$16.663 million compared to SCE's forecast of \$17.186 million.¹⁰⁸⁶ Cal Advocates does not oppose SCE's labor forecast for Security Technology, Operations and Maintenance or SCE's forecasts for Workforce Protection and Insider Threat Programs.

SCE argues Cal Advocates' recommendation regarding the Security Technology non-labor forecast is based on a misreading of historic non-labor costs. Prior to 2017, SCE charged the bulk of Physical Security BPE non-labor costs to the Workforce Protection/Insider Threat account. Starting in 2017, an accounting change resulted in certain non-labor costs shifting into the Security Technology account. SCE explains that the increases in the Security Technology account starting in 2017 are mirrored by decreases in the Workforce Protection/Insider Threat account, and that total non-labor costs for the Physical Security BPE have stayed relatively flat from 2014 to 2018.¹⁰⁸⁷

Cal Advocates does not provide any response to SCE's explanation. SCE's total historic costs from 2014-2018, below, (2018, \$000) corroborate SCE's explanation:¹⁰⁸⁸

¹⁰⁸⁵ Cal Advocates OB at 25.

¹⁰⁸⁶ *Ibid.*

¹⁰⁸⁷ Ex. SCE-15, Vol. 4 at 4.

¹⁰⁸⁸ *Id.* at 4, Table II-4. The recorded totals include both labor and non-labor costs.

Description	2014	2015	2016	2017	2018
Security Technology	3,238	4,015	4,437	26,594	22,547
Workforce Protection/ Insider Threat	22,112	24,782	23,834	(1,462)	166
Total	25,350	28,797	28,271	25,132	22,713

We find SCE has provided adequate justification for its Security Technology non-labor forecast, as well as the other forecasts included in its Physical Security BPE O&M forecast.¹⁰⁸⁹ Therefore, we approve SCE's total TY O&M forecast of \$23.588 million for the Physical Security BPE.

23.2. Physical Security Capital

SCE's capital projects for the Physical Security BPE for 2019-2021 include: (1) physical security upgrades for the protection of grid infrastructure, major business functions (non-electric facilities), and generation facilities; (2) physical security improvements at substations; (3) installation of smart key technology at most critical facilities; (4) deployment of unmanned aerial vehicle detection equipment at most critical facilities; (5) implementation of a new visitor management system; and (6) completion of projects for compliance with NERC CIP Standards.¹⁰⁹⁰ SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast capital expenditures (nominal, \$000) for the Physical Security BPE.¹⁰⁹¹

¹⁰⁸⁹ Ex. SCE-04, Vol. 4 at 19-20; Ex. SCE-15, Vol. 4 at 4-5.

¹⁰⁹⁰ Ex. SCE-04, Vol. 4 at 20-21.

¹⁰⁹¹ Ex. SCE-15, Vol. 4 at 6, Table II-5.

Capital Expenditures	2019	2020	2021
Protection of Grid Infrastructure Assets	12,952	38,652	27,715
Protection of Major Business Function Capital	9,581	9,988	13,424
Protection of Generation Assets	1,794	2,471	3,211
NERC Compliance Programs	31,572	13,342	7,386
Total	55,899	64,454	51,735

Cal Advocates recommends reductions to SCE's 2020 and 2021 forecasts for Protection of Grid Infrastructure Assets. Cal Advocates recommends adoption of SCE's recorded 2019 costs and does not oppose SCE's 2020 and 2021 forecasts for the other three programs.

We find reasonable and adopt SCE's recorded 2019 costs. We also find reasonable and adopt SCE's unopposed 2020 and 2021 forecasts. SCE provides adequate justification for the unopposed forecasts, including details regarding how program work is prioritized, the number of projects forecast for each program component, as well as forecast expenditures by program component.¹⁰⁹²

23.2.1. Protection of Grid Infrastructure Assets

The Protection of Grid Infrastructure Assets program involves security enhancements to key grid assets such as large substations. The activities in this program include: (1) upgrading fencing and lighting; (2) improving access control, video surveillance, and visitor management; and (3) implementing tamper-resistant gate motors, and intrusion and drone detection equipment.¹⁰⁹³ SCE prioritizes projects for this program based on criticality of the facility and impact to business function. SCE's forecast expenditures are based on 36 projects planned for 2020 and 42 projects planned for 2021.¹⁰⁹⁴

¹⁰⁹² Ex. SCE-04, Vol. 4 at 28-30, 42-43, 46-47.

¹⁰⁹³ *Id.* at 37.

¹⁰⁹⁴ *Id.* at 37-38, Tables II-14 and II-15.

Cal Advocates recommends a 2020 forecast of \$16.491 million and a 2021 forecast of \$16.821 million.¹⁰⁹⁵ Cal Advocates uses a five-year average of recorded 2015-2019 costs to forecast 2020 costs in order to reflect recent 2019 capital spending.¹⁰⁹⁶ Cal Advocates then escalates the 2020 forecast by two percent to determine the 2021 forecast in order to provide a gradual increase compared to the decrease SCE projects for 2020 to 2021.

Cal Advocates does not provide any analysis as to why the five-year average would be an appropriate basis for the 2020 forecast. To the extent Cal Advocates' recommendation is based on the fact that SCE's recorded 2019 costs were less than SCE forecast, SCE has already updated the 2019 capital forecast to reflect the 2019 recorded costs. SCE also explains that the lower 2019 costs were due to certain Tier 2 projects within the Tier Program component of the Protection of Grid Infrastructure Assets program being delayed until 2020 due to competing work on NERC CIP 014 (Tier 1) projects.¹⁰⁹⁷

SCE provides testimony and supporting documentation adequately justifying the need for the projects forecast for 2020 and 2021, and the basis for the cost forecasts.¹⁰⁹⁸ Cal Advocates does not dispute the justification or need for the projects. There is no evidence to support that Cal Advocates' recommended

¹⁰⁹⁵ Cal Advocates OB at 199.

¹⁰⁹⁶ SCE argues Cal Advocates calculated the five-year average using nominal dollars, rather than constant dollars, which is inconsistent with prevailing Commission guidance. (Ex. SCE-15, Vol. 4 at 8.) SCE calculates the five-year average from 2015-2019 as \$17.307 million based on constant dollars. (*Ibid.*)

¹⁰⁹⁷ *Ibid.* The Tier Program installs security measures at the most critical facilities based on the criticality of need and the potential impact of a security breach. (Ex. SCE-04, Vol. 4 at 32.) The substations are prioritized from Tier 1 for the most critical electric facilities to Tier 4 for the least critical. (*Id.* at 31-32.)

¹⁰⁹⁸ Ex. SCE-04, Vol. 4 at 31-35, 37-38; Ex. SCE-15, Vol. 4, Appendix A at A-4 to A-33.

forecasts would provide sufficient funding for the projects. Therefore, we find reasonable and adopt SCE's 2020 and 2021 forecasts.

24. Generation

SCE owns and operates approximately 2,600 megawatts (MW) of generating facilities: 33 hydroelectric plants, 5 gas-fired peaking units (Peakers), 2 battery storage systems, one combined-cycle gas plant (Mountainview Generating Station), a largely diesel-driven electric generating plant (Catalina Pebbly Beach Generating Station), 24 rooftop solar photovoltaic plants, and one ground-based solar photovoltaic plant. SCE also has a 15.8 percent interest in Palo Verde Nuclear Generating Station Units 1, 2, and 3. SCE's Generation Department operates and maintains all of these facilities and plants except for Palo Verde. The Generation Department also manages oversight of two demonstration fuel cell power plants.

SCE forecasts combined 2021 TY O&M expenses of \$160.748 million and combined 2019-2021 capital expenditures of \$282.486 million for its generation assets.¹⁰⁹⁹

Cal Advocates recommends that SCE's O&M forecasts be adopted as proposed.¹¹⁰⁰ Cal Advocates also recommends that SCE's 2019-2021 capital expenditure forecasts be adopted with the exception of SCE's 2020-2021 forecast for the Catalina Repower project.¹¹⁰¹

¹⁰⁹⁹ SCE OB at 203. The 2019-2021 capital expenditure forecast SCE presents in its opening brief does not appear to reflect the \$11 million reduction SCE made to the 2020-2021 forecast for the Catalina Repower Project. (See Ex. SCE-05, Vol. 1 at 157, Table III-43; Ex. SCE-54 at 196.)

¹¹⁰⁰ Ex. PAO-09 at 2.

¹¹⁰¹ *Ibid.*

TURN recommends various adjustments to SCE's O&M and capital expenditure forecasts for Hydro, Mountainview, Fuel Cell, Catalina, and Palo Verde.

24.1. Hydro

24.1.1. Hydro O&M

SCE initially proposed TY O&M expenses of \$42.028 million to operate and maintain its hydroelectric generation units and associated reservoirs, dams, waterways, and miscellaneous hydro facilities.¹¹⁰² SCE uses the last recorded year (2018) as the basis for its hydro labor forecast and the historical five-year (2014-2018) average as the basis for its non-labor forecast.

SCE subsequently revised its forecast to: (1) adopt TURN's recommendation to use 2018 last recorded non-labor costs instead of a five-year average for operating the retired Borel plant; and (2) reduce the labor forecast by an additional \$0.029 million as a result of incorrect timecard entries made to the Hydro O&M labor accounts.¹¹⁰³ With these two adjustments, SCE's TY forecast for Hydro O&M expenses is \$41.757 million.¹¹⁰⁴ We find reasonable and adopt this adjusted forecast.

24.1.2. Hydro Capital

Hydro capital expenditures include costs for investments in hydro infrastructure, equipment replacement, and compliance with FERC licensing requirements. SCE's proposed hydro capital projects fall into the following six categories: (1) relicensing, (2) dams and waterways, (3) prime movers,

¹¹⁰² Ex. SCE-05, Vol. 1 at 37.

¹¹⁰³ SCE OB at 204.

¹¹⁰⁴ *Ibid.*

(4) structures and grounds, (5) electrical equipment, and (6) decommissioning.¹¹⁰⁵ SCE forecasts 2019-2021 hydro capital expenditures of \$125.789 million.¹¹⁰⁶

SCE's forecast is unopposed except for TURN's recommendation that the Commission permanently disallow recovery of costs associated with the San Gorgonio hydro facility decommissioning project. SCE's 2019-2023 forecast for the San Gorgonio decommissioning project is \$6.705 million.¹¹⁰⁷ TURN opposes additional rate recovery because SCE has previously requested and received funding for the same project and scope of work in four prior GRCs, starting with the 2009 GRC, without completing the described and forecast work.¹¹⁰⁸ Alternatively, TURN recommends that if the Commission does not adopt a permanent disallowance, that it reject SCE's current forecast based on the low likelihood that the described decommissioning work will occur during the current GRC cycle.¹¹⁰⁹

TURN correctly notes that SCE has submitted the same scope of work for this project in five consecutive GRCs, including this GRC.¹¹¹⁰ However, we do not find justification for a permanent disallowance. SCE's prior forecasts for this project were found to be reasonable by the Commission in prior GRCs based on the information that was available at the time those decisions were made. We do not now second-guess those determinations based on subsequent events.

¹¹⁰⁵ SCE provides details regarding its proposed hydro capital projects in Ex. SCE-05, Vol. 1 at 48-113.

¹¹⁰⁶ Ex. SCE-16, Vol. 1 at 9.

¹¹⁰⁷ Ex. SCE-54 at 197.

¹¹⁰⁸ TURN OB at 147.

¹¹⁰⁹ *Id.* at 147-148.

¹¹¹⁰ Ex. TURN-09-Atch1, Attachment 5.

We acknowledge that the failure to start full-scale decommissioning of San Gorgonio is due to events beyond SCE's control. SCE explains that the FERC license surrender and transfer process has been protracted and adversarial due to water rights issues between the U.S. Forest Service (USFS) and local Participating Entities.¹¹¹¹ SCE cannot begin physical decommissioning activities until the FERC license and transfer process is complete.

Although we do not find justification for a permanent disallowance, we find that SCE has failed to justify its proposed decommissioning costs for this GRC cycle. SCE has not provided any evidence demonstrating that the disputes between USFS and the local Participating Entities will be resolved, and the necessary FERC approval obtained in a timeframe that would enable SCE to perform the decommissioning work forecast for this GRC cycle.¹¹¹² Especially given the past history for this project, we do not find it reasonable to approve SCE's requested costs for this work absent this evidence.

SCE notes that it has spent an average of \$0.408 million annually since the inception of the project to, among other things, maintain the facility in a safe condition, meet regulatory requirements, pay required taxes and fees, and meet contractual commitments.¹¹¹³ We find it reasonable to approve \$0.408 million annually for 2020 and 2021 in order for SCE to address ongoing safety, regulatory, and other requirements during this GRC cycle. For 2019, consistent with our treatment of 2019 capital expenditures for other BPEs, we find reasonable and approve SCE's recorded 2019 capital expenditures of

¹¹¹¹ Ex. SCE-16, Vol. 1 at 13-15.

¹¹¹² See TURN OB at 150-151.

¹¹¹³ Ex. SCE-16, Vol. 1 at 12.

\$0.790 million for the project.¹¹¹⁴ We also find reasonable and approve the remainder of SCE's unopposed 2019-2021 forecast for hydro capital expenditures.

We do not preclude SCE from seeking additional recovery for San Gorgonio decommissioning activities in a future GRC. SCE will need to demonstrate that the forecast decommissioning work is likely to be conducted during that GRC cycle and that its cost estimates are reasonable. SCE will also need to demonstrate that additional rate recovery for the project is reasonable despite the fact that the Commission has approved costs for the same scope of work in prior GRCs.¹¹¹⁵

24.2. Mountainview

24.2.1. Mountainview O&M

SCE initially proposed TY O&M expenses of \$29.409 million to operate and maintain Mountainview.¹¹¹⁶ The 2021 TY O&M expense forecast is based on 2018 recorded expense for labor with a \$0.600 million downward adjustment for expected lower overtime requirements due to additional hires, a four-year average of the 2015-2018 recorded expense for non-labor,¹¹¹⁷ and one-third (*i.e.*,

¹¹¹⁴ Ex. SCE-54 at 197.

¹¹¹⁵ See additional discussion in Section 40.1, below regarding renewed requests for funding.

¹¹¹⁶ Ex. SCE-05, Vol. 1 at 133.

¹¹¹⁷ Mountainview uses General Electric (GE) supplied major power island equipment including the combustion turbine generators, steam turbine generators, and controls. GE provides continuous condition monitoring and warranty repair coverage and major maintenance of the equipment pursuant to a Contractual Services Agreement. SCE executed a new Contractual Services Agreement with GE in 2015. (*Id.* at 131-132.) Since 2014 costs were incurred under a prior agreement, SCE excludes 2014 costs in developing its Mountainview non-labor forecast and does not use a 5-year (2014-2018) average as it does for most of its other generation O&M non-labor forecasts.,

the 2021 through 2023 annual average) of the forecast cost of the Mountainview Major Inspection Overhaul planned for 2021 and 2022.¹¹¹⁸

TURN recommends two adjustments to SCE's forecast. First, TURN recommends a reduction of \$0.822 million to account for lower expected payments under the Contract Services Agreement with GE due to changing operations at the facility attributable to greater renewable resource production.¹¹¹⁹ TURN argues that costs prior to 2019 are likely to be unrepresentative, and therefore, bases its recommendation on 2019 recorded costs instead of the four-year average used by SCE. Second, TURN recommends a reduction of \$0.158 million based on applying a non-labor escalation rate of 7.3 percent to the 2013 major inspection cost used to calculate the 2021 TY forecast.¹¹²⁰

SCE does not oppose TURN's recommendations and also notes that SCE corrected the escalation rate error with errata.¹¹²¹ With these two adjustments, SCE's 2021 TY forecast for Mountainview O&M expenses is \$28.429 million.¹¹²² We find reasonable and adopt the adjusted forecast.

24.2.2. Mountainview Capital

SCE initially forecast capital expenditures of \$66.618 million for 2019-2021 for Mountainview to support reliable service, compliance with applicable laws and regulations, and safe operations for employees and the public.¹¹²³ Based on a

¹¹¹⁸ *Id.* at 133-138.

¹¹¹⁹ Ex. TURN-09 at 21-22.

¹¹²⁰ *Id.* at 20.

¹¹²¹ SCE OB at 211.

¹¹²² *Id.* at 210.

¹¹²³ The proposed projects are described in Ex. SCE-05, Vol. 1 at 140-143.

recommendation by TURN, SCE subsequently revised its forecast to remove the purchase of three spare combustion turbine rotors because SCE determined that it was highly unlikely that the purchase will need to occur during this GRC cycle.¹¹²⁴ Removal of this purchase results in a revised forecast of \$14.382 million.¹¹²⁵ We find reasonable and adopt the revised forecast.

24.3. Solar

24.3.1. Solar O&M

SCE owns and operates twenty-five solar generating plants¹¹²⁶ constructed as part of the SCE Solar Photovoltaic Program (SPVP) with a combined total capacity of 91.4 MW DC. SCE forecasts TY O&M expenses of \$3.755 million based on 2018 recorded labor expense, the historical five-year average (2014-2018) for non-labor expense and interconnection fees, and an itemized forecast for the site leases based on 2018 scheduled lease payment obligations.¹¹²⁷ We find reasonable and adopt SCE's unopposed forecast.

24.3.2. Solar Capital

SCE's 2019-2021 capital expenditure forecast for SPVP is \$4.078 million.¹¹²⁸ Most of this forecast is due to SCE's recorded 2019 capital expenditures to decommission the Perris facility (\$3.776 million).¹¹²⁹ The remainder of the forecast capital expenditures include purchase of spare parts and other capital

¹¹²⁴ Ex. TURN-09 at 19; Ex. SCE-16, Vol. 1 at 21.

¹¹²⁵ *Id.* at 20, Table III-9. The revised forecast also incorporates 2019 recorded costs.

¹¹²⁶ As discussed below, SCE decommissioned one of these plants, the Perris facility, in 2019.

¹¹²⁷ Ex. SCE-05, Vol. 1 at 167-169.

¹¹²⁸ Ex. SCE-16, Vol. 1 at 38, Table IV-16.

¹¹²⁹ *Id.* at 40, Table IV-17.

designated replacement components that fail in service.¹¹³⁰ We find reasonable and adopt SCE's unopposed forecast.

24.4. Fuel Cell

SCE owns and operates two fuel cell generating plants at the University of California Santa Barbara and California State University San Bernardino with a combined total capacity of 1.6 MW. SCE initially proposed a 2021 TY O&M forecast of \$0.491 million based on 2018 recorded labor expense and a five-year average (2014-2018) of recorded non-labor expense.¹¹³¹ SCE does not forecast any capital expenditures for the Fuel Cells.

TURN recommends 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.¹¹³² SCE removed these facilities charges from non-labor expense in 2018 and forecasts the charges as a separate line item in its 2021 TY forecast.¹¹³³ SCE does not oppose TURN's recommendation.¹¹³⁴ We find reasonable and adopt the adjusted 2021 TY forecast of \$0.472 million.

24.5. Catalina

24.5.1. Catalina O&M

SCE initially proposed TY O&M expenses of \$5.481 million to operate and maintain its Catalina Generation units.¹¹³⁵ SCE uses the last recorded year (2018) as the basis for its labor forecast and the historical five-year (2014-2018) average as the basis for its non-labor forecast.

¹¹³⁰ Ex. SCE-05, Vol. 1 at 169.

¹¹³¹ *Id.* at 163.

¹¹³² Ex. TURN-09 at 27.

¹¹³³ Ex. SCE-05, Vol. 1 at 163.

¹¹³⁴ SCE OB at 212.

¹¹³⁵ Ex. SCE-05, Vol. 1 at 157.

TURN recommends reducing the non-labor forecast by \$0.103 million to remove an atypical outage that occurred in 2016 that is unlikely to recur in the current GRC cycle.¹¹³⁶ SCE does not oppose TURN's recommendation.¹¹³⁷ With this adjustment, SCE's 2021 TY forecast for Catalina O&M expenses is \$5.378 million.¹¹³⁸ We find reasonable and adopt the adjusted forecast.

24.5.2. Catalina Capital

SCE's Catalina capital expenditures forecast includes funding for the following projects: the Catalina Repower project, the Pebbly Beach Generating Station (PBGS) resurface paving project, and a 2.4kV Switch Upgrade project.¹¹³⁹ Based on updates provided in rebuttal testimony and the joint comparison exhibit, SCE's total capital expenditure forecast for 2019-2021 is \$14.486 million, consisting of recorded 2019 costs of \$5.186 million; forecast 2020 costs of \$0.500 million for Catalina Repower and \$1.500 million for resurface paving; and forecast 2021 costs of \$5.300 million for Catalina Repower and \$2.000 million for resurface paving.¹¹⁴⁰

We find reasonable and approve SCE's unopposed requests to recover funding for its 2019 recorded costs¹¹⁴¹ and its 2020 and 2021 forecasts for the resurface paving project. For the reasons discussed below, we deny SCE's

¹¹³⁶ TURN OB at 154-155.

¹¹³⁷ SCE OB at 213.

¹¹³⁸ *Ibid.*

¹¹³⁹ Ex. SCE-05, Vol. 1 at 157.

¹¹⁴⁰ *Id.* at 157, Table III-43; Ex. SCE-16, Vol. 1, Appendix B at B3; Ex. SCE-54 at 196.

¹¹⁴¹ This includes 2019 recorded costs for the Catalina Repower project. The joint comparison exhibit indicates that Cal Advocates and TURN do not oppose SCE's request to recover the 2019 recorded costs for the project. (Ex. SCE-54 at 196.)

request to recover its 2020 and 2021 forecast costs for the Catalina Repower project.

Six diesel engine generators (9.4 MW) at SCE's PBGS provide the primary power generation to Catalina Island. The Catalina Repower project proposes to replace the 6 diesel electric generators to meet new emissions requirements set forth by the South Coast Air Quality Management District (SCAQMD).¹¹⁴² In order to maintain reliability and service load, SCE proposes to replace the generators in three phases with two of the existing generators being replaced with two new SCAQMD compliant generators during each phase.¹¹⁴³ SCE explains that it must install 2 new clean diesel generators by January 1, 2023 to meet the compliance deadline for a Nitrogen Oxide (NOx) emissions reduction target set forth in SCAQMD Rule 1135.¹¹⁴⁴

Both Cal Advocates and TURN recommend that the Catalina Repower project be removed from the forecast for this GRC due to uncertainty surrounding the timing and scope of the overall project. TURN argues that the record does not support that any new diesel generation will be in service by the TY.¹¹⁴⁵ TURN recommends that SCE submit its proposals in the Integrated Resources Planning docket and demonstrate the reasonableness of its choices in the next GRC. Cal Advocates recommends that SCE file a separate application to seek cost recovery if it completes the project.

The need for a project to replace the generators in order to comply with new SCAQMD requirements is clear. However, due to the uncertainty regarding

¹¹⁴² Ex. SCE-05, Vol. 1 at 158.

¹¹⁴³ *Id.* at 159.

¹¹⁴⁴ SCE OB at 214.

¹¹⁴⁵ TURN OB at 160.

the scope and timing of SCE's proposed project, we find that additional review of the project is warranted prior to approving funding for 2020 and 2021.

The details for the project have changed during the pendency of this proceeding. SCE initially proposed to replace the generators in three phases with two of the existing generators being replaced during each phase.¹¹⁴⁶ SCE forecast in-service dates of April 2021 for Phase 1, April 2022 for Phase 2, and April 2023 for Phase 3.¹¹⁴⁷

During evidentiary hearings, SCE witness Buerkle stated that no final decision had been made to proceed with the installation of new diesel generation at Catalina.¹¹⁴⁸ SCE indicated that the forecast in-service dates provided in prepared testimony were illustrative and that no binding commitments had been made to suppliers or vendors.¹¹⁴⁹

In the joint comparison exhibit served after the hearings, SCE updated its Catalina Repower capital project to reflect that the project's start date would be delayed by approximately 1 year.¹¹⁵⁰ Based on SCE's initial schedule, this suggests that Phase 1 would not be complete until April 2022 and that no new generators would be in-service in the TY.

The status of Phases 2 and 3 is also unclear. SCE's initial proposal was to replace all 6 generators. However, SCE states that it is still exploring alternative

¹¹⁴⁶ Ex. SCE-05, Vol. 1 at 159, Table III-44.

¹¹⁴⁷ *Ibid.*

¹¹⁴⁸ RT, Vol. 4 at 539:19-24.

¹¹⁴⁹ *Id.* at 540:11-23.

¹¹⁵⁰ Ex. SCE-54 at 195. SCE updated its forecast to reflect 2019 recorded costs and to adjust the rest of the original forecast by one year (*i.e.*, move 2020 costs to 2021, etc.). SCE's updated 2019-2022 capital expenditure forecast for Phase 1 of the Catalina Repower project is \$18.056 million. (SCE OB at 214.)

options, including solutions involving a combination of diesel generators, renewable projects, and storage.¹¹⁵¹ SCE indicates that some of the alternative options it is pursuing could eliminate the need for some of the proposed diesel generating units.¹¹⁵²

Based on the latest timeline provided by SCE, no part of the project will be in-service by the TY. Moreover, although SCE indicates a need to install 2 new clean diesel generators by January 1, 2023, the rest of the scope and timing for the project remain uncertain. Therefore, we deny SCE's request for approval of its 2020 and 2021 forecasts for this project.

We also note that intervenors have not had an adequate opportunity to review the proposed project due to uncertainty regarding the project details and late changes to the scope. Intervenors have not had an opportunity to question SCE about the latest update to the project scope and cost, which SCE provided after hearings. Intervenors also have not had an opportunity to question SCE regarding the final feasibility study into Catalina Island repower options,¹¹⁵³ which SCE submitted into the record more than one month after the relevant SCE witness appeared on the stand during hearings.

Given SCAQMD's air quality concerns necessitating the repower project in the first place, as well as the long-term power implications of this project for Catalina Island, we find that additional scrutiny of the proposed project is warranted. Therefore, we direct SCE to submit a standalone application with its most up to date version of the Catalina Repower project proposal within 60 days of the issuance of this decision. Although the immediate focus of the application

¹¹⁵¹ RT, Vol. 4 at 542-544.

¹¹⁵² *Id.* at 544:2-6.

¹¹⁵³ Ex. SCE-44.

should be on Phase 1 and any actions needed to meet SCAQMD's January 1, 2023 deadline, SCE should also submit its proposal for the overall project for review. We also authorize SCE to create a Catalina Repower Memorandum Account to track costs related to the project for possible future recovery following a reasonableness review in the next GRC.

24.6. Palo Verde

24.6.1. Palo Verde O&M

SCE owns a 15.8 percent share of Palo Verde Nuclear Generating Station (Palo Verde) located near Phoenix, Arizona. Arizona Public Service Company (APS) operates Palo Verde and SCE compensates APS for its 15.8 percent share of expenses. SCE forecasts TY O&M expenses of \$73.331 million, consisting of \$0.235 million for labor and \$73.096 million for non-labor.¹¹⁵⁴

TURN makes the following recommendations: (1) SCE's non-labor forecast should be reduced by 7.59 percent from 2018 actual spending to reflect the most recent budget adopted by APS; (2) SCE's share of Palo Verde's annual Nuclear Energy Institute (NEI) membership dues of \$278,000 should be reduced by 50 percent or \$139,000 consistent with Commission precedent; and (3) Palo Verde water sales revenues should be removed from Non-Tariffed Products and Services (NTP&S) and treated as an increase in Other Operating Revenues credited to customers. TURN's recommendations result in an O&M non-labor forecast of \$71.451 million.¹¹⁵⁵

¹¹⁵⁴ SCE OB at 218. SCE's OB also argues that the Commission should approve an O&M forecast of \$73.340 million (\$2018), consisting of \$0.235 million for labor and \$73.105 million for non-labor. (SCE OB at 220.) The difference in the non-labor expense forecasts is due to a \$0.009 adjustment for NEI dues, discussed further below. In its rebuttal testimony and OB, SCE at times states that its non-labor expense forecast is \$73.096 million and other times states that it is \$73.105 million.

¹¹⁵⁵ Ex. TURN-09 at 10.

24.6.1.1. Labor Expense

SCE's Palo Verde O&M labor forecast is based on the last recorded year (2018) plus a TY adjustment of \$86,000. The adjustment from 2018 recorded is due to SCE transferring Palo Verde Fuel Services functions to the SCE Nuclear Finance Division late in 2018 and SCE's determination that personnel who perform regulatory work related to Palo Verde will now charge their time to Palo Verde oversight.¹¹⁵⁶ We find reasonable and approve the unopposed labor forecast.

24.6.1.2. Non-Labor Expense

SCE relies on a budget prepared by APS in July 2018 as the basis for its corrected 2021 non-labor forecast of \$73.096 million (\$2018).¹¹⁵⁷ TURN recommends a 7.59 percent reduction from 2018 actual spending based on an updated budget approved by APS on November 20, 2019.¹¹⁵⁸ TURN's recommendation results in a \$1.516 million reduction to SCE's corrected forecast.¹¹⁵⁹

SCE does not dispute the accuracy of the updated APS budget but argues that it is unfair for TURN to use a budget that was unavailable at the time SCE developed the forecast.¹¹⁶⁰ SCE fails to provide a compelling reason why the updated budget should not be used. TURN timely presented this information during the scheduled time for intervenor testimony. We find it reasonable to use

¹¹⁵⁶ Ex. SCE-05, Vol. 1 at 180.

¹¹⁵⁷ Ex. SCE-16, Vol. 1 at 42, Table V-18 and 44. In rebuttal testimony, SCE corrected the forecast presented in its direct testimony from nominal dollars to 2018 constant dollars and also adjusted the forecast by \$0.009 million for its rebuttal position on NEI dues.

¹¹⁵⁸ Ex. TURN-09 at 9.

¹¹⁵⁹ TURN OB at 161-162. This difference is based on a comparison to SCE's forecast non-labor expense without the \$0.009 million NEI adjustment.

¹¹⁶⁰ SCE OB at 220.

the most up to date budget information available in the record and adopt TURN's recommended reduction to the non-labor forecast.

24.6.1.3. Nuclear Energy Institute Dues

Palo Verde is a member of the NEI, which is the policy organization of the nuclear technologies industry. SCE includes its share of NEI membership dues (\$278,000) as Palo Verde non-labor expense.

TURN recommends that the Commission remove 50 percent (\$139,000) of NEI fees from the Palo Verde non-labor forecast. TURN argues that the Commission has consistently removed half of the costs for NEI dues in recent GRC cases, recognizing the organization's dual role of promoting nuclear power through public relations and lobbying, while also working to cut industry costs.¹¹⁶¹

SCE argues that the significant cost-saving benefits provided by NEI justifies the recovery of more than 50 percent of NEI costs. SCE argues that, if the Commission adopts TURN's recommendation to remove a percentage of NEI fees from the forecast, the Commission should only remove a \$10,000 voluntary contribution to the Foundation for Nuclear Studies and SCE's share of the 2.5 percent of the NEI fees charged to Palo Verde, which is the public relations/lobbying percentage that NEI reported to the Internal Revenue Service.¹¹⁶²

In SCE's 2006 GRC, the Commission noted that "the principal focus of NEI appears to be the advocacy of nuclear power, both nationally and globally" and that "many aspects of such furtherance of the nuclear industry ... may not be

¹¹⁶¹ TURN OB at 164.

¹¹⁶² SCE OB at 222.

appropriate for ratepayer funding.”¹¹⁶³ Due to the lack of information regarding the “specific activities and related benefits that accrue to the company and/or ratepayers,” the Commission found it reasonable to adopt a 50/50 split of NEI dues between shareholders and ratepayers.¹¹⁶⁴ The Commission directed that if SCE requests a different allocation of NEI dues in the future, “SCE should provide more detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits.”¹¹⁶⁵

We find that SCE has failed to provide the required additional information that would justify a different allocation of NEI dues. SCE generally asserts that NEI provides substantial cost-savings benefits for customers and describes some of NEI’s activities.¹¹⁶⁶ However, SCE fails to establish that all the benefits of NEI membership go to ratepayers. The extent to which the benefits accrue to customers as opposed to the company is unclear.

SCE argues that it is reasonable to limit any removal of the NEI fees to the percentage of fees attributable to lobbying expenses, which NEI itemizes in invoices sent to its members. Pursuant to Internal Revenue Code (IRC) Section 6033(e), NEI is required to disclose its expenditures for certain lobbying and political activities listed in IRC Section 162(e)(1).¹¹⁶⁷ These lobbying and political activities include activities to influence legislation, support a candidate for

¹¹⁶³ D.06-05-016 at 35.

¹¹⁶⁴ *Ibid.*

¹¹⁶⁵ *Ibid.*

¹¹⁶⁶ Ex. SCE-16, Vol. 1 at 46.

¹¹⁶⁷ Ex. TURN-44, SCE Response to TURN Data Request 91, Question 3.a.

elected office, influence election or legislative outcomes, or directly communicate with senior executive branch officials regarding agency actions.¹¹⁶⁸

NEI engages in advocacy activities that extend beyond the activities classified as lobbying under Section 162(e)(1).¹¹⁶⁹ It is unclear what portion of NEI membership dues fund these advocacy activities. It is also unclear to what extent ratepayers as opposed to the industry benefit from these advocacy activities.

Based on the foregoing, we do not find justification for a departure from our past treatment for NEI dues. Therefore, we continue to authorize ratepayer funding of 50 percent of SCE's share of the NEI dues.

24.6.1.4. Excess Water Sales Revenue

SCE argues that revenue from Palo Verde excess water sales is appropriately treated as NTP&S. SCE argues that, pursuant to SCE's Gross Revenue Sharing Mechanism adopted in D.99-09-070, these revenues are considered "passive," which results in ratepayers receiving 30 percent of the gross incremental revenues.¹¹⁷⁰ After responding to a data request from TURN on this issue, SCE became aware that the established accounting was incorrectly netting the Palo Verde water sale revenues against O&M expenses, resulting in the Gross Incremental Revenues not being shared with customers. SCE states that it will provide customers with their portion of the 30 percent allocation in its next Electric Deferred Refund Account submission in January 2021.¹¹⁷¹

¹¹⁶⁸ 26 U.S.C. § 162(e)(1).

¹¹⁶⁹ TURN OB at 169-170.

¹¹⁷⁰ SCE OB at 222.

¹¹⁷¹ *Id.* at 222-223.

TURN proposes that SCE continue to treat the excess water sales revenues as Other Operating Revenue, which is how SCE has treated these revenues for almost 20 years. TURN's proposal would result in a \$0.474 million offset against the Palo Verde O&M forecast.¹¹⁷² TURN argues that since SCE has not previously sought to classify Palo Verde water sales as NTP&S, this product offering would be considered "new," and therefore, must satisfy the requirements set forth in Affiliate Transaction Rule VII(D) (Conditions Precedent to Offering New Products and Services) originally adopted in D.97-12-088 and modified in D.98-08-035.¹¹⁷³ TURN argues that SCE has failed to establish that it meets these requirements.

Contrary to TURN's assertions, Palo Verde excess water sales are not a new category or activity requiring approval under Affiliate Transaction Rule VII(D). These sales fall under SCE's existing NTP&S offering "sale or trading of excess water rights" under the Secondary Use of Utility-Owned Generation Facilities and Land category, previously approved by the Commission in Resolution E-3639.¹¹⁷⁴ This NTP&S offering is currently reflected in SCE's tariff sheet Preliminary Statement, Part G, Gross Revenue Sharing Mechanism. The Commission has designated these types of excess water sales as "passive," which

¹¹⁷² TURN OB at 171.

¹¹⁷³ *Id.* at 172-173.

¹¹⁷⁴ On January 6, 2000, the Commission issued Resolution E-3639 conditionally approving SCE's Advice Letter (AL) 1286-E, in which SCE set forth its existing NTP&S offerings and requested authorization to continue to offer the listed products and services. AL 1286-E listed "sale or trading of excess water rights" as an existing offering under the Secondary Use of Utility-Owned Generation Facilities and Land category. Resolution E-3639 conditioned approval of AL 1286-E on SCE providing additional information in a supplemental advice letter, which SCE provided in AL 1286-E-A submitted on April 5, 2000.

pursuant to the Gross Revenue Sharing Mechanism adopted in D.99-09-070, results in customers being allocated 30 percent of gross revenues.

SCE's correction of its accounting error and classification of Palo Verde excess water sales as passive NTP&S is treatment the Commission has previously authorized in D.99-09-070 and Resolution E-3639. Therefore, no further showing from SCE is necessary.

24.6.2. Palo Verde Capital

As the operating agent for Palo Verde, APS identifies and implements capital projects to support safe and reliable plant operation and meet regulatory requirements.¹¹⁷⁵ SCE and the other participants review and approve projects and the annual capital budget under the Palo Verde Engineering and Operations Committee procedures.¹¹⁷⁶

SCE's 2019-2021 capital expenditure forecast for Palo Verde is \$110.707 million.¹¹⁷⁷ We find reasonable and adopt SCE's unopposed forecast.

24.7. Peakers

24.7.1. Peakers O&M

SCE forecasts TY O&M expenses of \$7.624 million to operate and maintain its five Peaker plants.¹¹⁷⁸ SCE uses the last recorded year (2018) as the basis for its labor forecast and the historical five-year (2014-2018) average as the basis for its non-labor forecast. We find reasonable and approve SCE's uncontested O&M forecast.

¹¹⁷⁵ Ex. SCE-05, Vol. 1 at 181.

¹¹⁷⁶ *Ibid.*

¹¹⁷⁷ Ex. SCE-16, Vol. 1 at 49, Table V-19.

¹¹⁷⁸ Ex. SCE-05, Vol. 1 at 149.

24.7.2. Peakers Capital

SCE forecasts 2019-2021 capital expenditures of \$2.044 million for its Peaker plants.¹¹⁷⁹ The forecast projects for this period include a fire water tank and booster pump installation and continuous emissions monitoring system replacements.¹¹⁸⁰ We find reasonable and approve SCE's uncontested 2019-2021 capital expenditures forecast.

25. Energy Procurement

SCE's Energy Procurement and Management (EPM) procures and schedules electricity from independent power producers and suppliers to supplement SCE's utility-owned generation. EPM manages approximately \$4 billion of energy procurement spend annually, which is forecast and recorded in SCE's annual Energy Resource Recovery Account (ERRA) proceeding. The O&M costs and capital expenditures associated with performing energy procurement functions are determined in the GRC.

25.1. Energy Procurement O&M

SCE forecasts TY O&M expenses of \$24.568 million for EPM.¹¹⁸¹ SCE uses the last recorded year (2018) as the basis for its labor forecast. Since non-labor expense has decreased every year from 2014-2018, SCE bases the non-labor expense forecast on 2018 recorded costs with an upward adjustment of \$0.096 million for subscription fees and other miscellaneous non-labor expenses anticipated in the TY.¹¹⁸² SCE proposes to reduce its O&M forecast by \$1.045 million if the Commission approves its 2021 ERRA Forecast Application

¹¹⁷⁹ Ex. SCE-16, Vol. 1 at 23.

¹¹⁸⁰ Ex. SCE-05, Vol. 1 at 152-154.

¹¹⁸¹ Ex. SCE-05, Vol. 2 at 15, Figure II-5.

¹¹⁸² *Id.* at 17-18.

(A.20-07-004) proposal to recover certain non-labor expenses (California Air Resources Board (CARB) fees, subscription costs, and consulting fees) through non-GRC recovery mechanisms.¹¹⁸³

SCE's O&M forecast and proposal to reduce the forecast depending on the outcome of the 2021 ERRA Forecast Application are unopposed. In the decision on SCE's 2021 ERRA Forecast Application, D.20-12-035, the Commission approved SCE's proposals to recover the non-labor expenses specified above through non-GRC recovery mechanisms. Therefore, we find reasonable and approve SCE's O&M forecast of \$24.568 million less \$1.045 million for a total forecast of \$23.523 million.

25.2. Energy Procurement Capital

SCE's 2019-2021 EPM capital expenditure forecast of \$3.074 million is unopposed.¹¹⁸⁴ These capital expenditures are for the installation and configuration of communications equipment and telemetry data links, which are required to bring new generation resources into SCE's portfolio. We find reasonable and approve the unopposed capital expenditure forecast.

26. Enterprise Technology

The Enterprise Technology BPE includes activities and infrastructure to support SCE's broader Information Technology (IT) needs. SCE requests O&M and capital expenditures to perform work to manage its technology environment including over 7,500 midrange servers, 2,000 terabytes of data storage, 700 miles of data network routing and switching infrastructure, 400 appliances supporting

¹¹⁸³ *Id.* at 18.

¹¹⁸⁴ Ex. SCE-16, Vol. 2 at 5.

over 500 large data repository solutions, and operations of SCE's three primary data centers.¹¹⁸⁵

26.1. Enterprise Technology O&M

SCE forecasts TY O&M expenses of \$216.717 million for the Enterprise Technology BPE. This forecast includes work for the following activities:¹¹⁸⁶

Activity	TY Forecast (\$000)
Technology Planning, Design, and Support	9,868
Technology Delivery	11,188
Fixed Price Technology and Maintenance	76,632
Software Maintenance and Replacement	97,245
Technology Infrastructure Maintenance and Replacement	21,784
Total	216,717

Cal Advocates recommends a TY forecast of \$200.652 million.¹¹⁸⁷

Cal Advocates recommends reductions to: (1) the Fixed Price Technology and Maintenance, and (2) Software Maintenance and Replacement forecasts.

Cal Advocates does not oppose the other forecasts.

We find SCE has provided adequate support for the unopposed Technology Planning, Design, and Support; Technology Delivery; and Technology Infrastructure Maintenance and Replacement forecasts.¹¹⁸⁸ We find the forecasts to be reasonable and adopt them. The contested forecasts are discussed below.

¹¹⁸⁵ Ex. SCE-06, Vol. 1, Pt. 1AE at 1.

¹¹⁸⁶ Ex. SCE-17, Vol. 1 at 2, Table I-1.

¹¹⁸⁷ Cal Advocates OB at 208.

¹¹⁸⁸ Ex. SCE-06, Vol. 1, Pt. 1A at 15-16, 20-22, 75-77; Ex. SCE-06, Vol. 1, Pt. 1AE at 64-66.

26.1.1. Fixed Price Technology and Maintenance

Fixed Price Technology and Maintenance work activity is primarily responsible for IT services provided by two Managed Service Providers (MSPs) for day-to-day IT functions. The MSPs provide support, development, and testing for 800 applications; management of three enterprise data centers; support and maintenance for the customer service system mainframe; all IT service management functions; the 24-hour service desk; and support/maintenance for 16,000 end user laptops and desktops.¹¹⁸⁹ This work activity also includes three related SCE labor functions: IT service management, sourcing, and the service provider management office.¹¹⁹⁰

SCE forecasts TY O&M expenses of \$76.632 for Fixed Price Technology and Maintenance, consisting of \$3.032 million for labor and \$73.600 million for non-labor. SCE's labor forecast is based on last year recorded (2018) costs plus a \$200,000 increase to account for additional support related to Grid Modernization and Digital Managed Services.¹¹⁹¹ SCE's non-labor forecast is based on MSP contractual pricing. SCE forecasts a \$7 million increase from recorded 2018 non-labor costs in order to provide operational support for major programs such as Digital Managed Services and Grid Modernization, smaller projects that will be moving into production, and incremental services to support the legacy Customer Service System.¹¹⁹²

¹¹⁸⁹ Ex. SCE-06, Vol. 1, Pt. 1A at 24.

¹¹⁹⁰ *Id.* at 24-25.

¹¹⁹¹ *Id.* at 27.

¹¹⁹² *Id.* at 27-28.

Cal Advocates recommends a TY forecast of \$71.586 million.¹¹⁹³

Cal Advocates does not oppose SCE's labor forecast but recommends a \$5.046 million reduction to the non-labor forecast. Cal Advocates averages the last four years of recorded costs (2015-2018) to determine the non-labor forecast. Cal Advocates notes that in 2018, SCE's spending was \$7.9 million below the authorized amount primarily due to savings incurred through negotiations. Cal Advocates contends that these negotiations can be expected to reduce expenses in the TY. Cal Advocates also notes that SCE forecast \$75.614 million for 2019 but only recorded \$68.503 million. Cal Advocates argues that SCE's downward trend in spending and similarity between SCE's 2021 and 2019 forecasts further support Cal Advocates' reduced forecast.

In rebuttal, SCE argues that its non-labor forecast based upon agreed contractual pricing is the most reasonable estimate of the expenses SCE expects to incur in 2021. SCE explains that the savings SCE realized from negotiations are unique to 2018 and 2019 because the savings relate to support for major programs (Grid Modernization, Digital Managed Services, and Customer Service Re-Platform) and projects that were delayed and not placed into production in 2018 and 2019.¹¹⁹⁴ SCE contends that these major programs and projects will go into production and require operational support in the TY.

We find SCE's TY forecast to be adequately supported. SCE justifies the lower recorded 2018 and 2019 costs and why these costs are not likely to be representative of TY expenses. We find reasonable and adopt SCE's TY forecast.

¹¹⁹³ Ex. PAO-10 at 2, 6-7.

¹¹⁹⁴ Ex. SCE-17, Vol. 1 at 7-8.

26.1.2. Software Maintenance and Replacement

Software Maintenance and Replacement includes costs required to maintain SCE's operating software assets through on-premise license, cloud, subscription, and maintenance contract agreements. This work activity also includes application refresh activities consisting of the management, maintenance, optimization, and monitoring of about 800 IT applications and more than 3,000 interfaces through their lifecycles. The work is divided into 4 sub-work activities: (1) Perpetual License, (2) Software as a Service, (3) Cloud (Subscription Based Software), and (4) Application Refresh.

SCE's 2021 O&M forecast for Software Maintenance and Replacement is \$89.586 million. SCE's TY O&M request is \$97.245 million because SCE normalizes its forecast for ratemaking purposes to account for expected increases in costs in 2022 and 2023. SCE's 2021-2023 forecasts for Software Maintenance and Replacement sub-work activities are as follows:¹¹⁹⁵

Sub-Work Activity		Forecast (\$000)		
		2021	2022	2023
Application Refresh	Labor	8,689	8,689	8,689
	Non-Labor	8,845	19,130	12,980
Cloud (Non-Labor Only)		18,130	18,720	20,628
Perpetual License (Non-Labor Only)		53,922	58,843	54,569
Total		89,586	105,382	96,766
Normalization Adjustment		7,659	(8,137)	479
Total with Normalization		97,245	97,245	97,245

SCE's labor forecast is based on last year recorded (2018) costs plus an increase of approximately \$1.5 million for additional FTEs to manage projected increases in application refreshes and staff transferring back to Operations

¹¹⁹⁵ Ex. SCE-06, Vol. 1, Pt. 1A at 28, Table IV-3; 38, Table IV-7; and 45, Table IV-11.

following completion of the CSRP project. SCE's non-labor forecasts are based on itemized forecasts.¹¹⁹⁶

Cal Advocates recommends a TY forecast of \$85.818 million. First, Cal Advocates recommends a \$3.768 million reduction to SCE's combined Cloud and Perpetual License forecast based on use of a two-year (2019-2020) average. Cal Advocates argues that a two-year average is appropriate because SCE's forecast increase in 2021 for these activities is due to CSRP implementation and SCE has informed the Commission that CSRP has been removed from this proceeding.¹¹⁹⁷ Secondly, Cal Advocates recommends a \$7.659 million reduction to SCE's forecast based on removal of SCE's normalization adjustment. Cal Advocates argues that ratepayers in 2021 do not receive benefits for expenses forecast for 2022 and 2023, and that it is uncertain whether those higher forecast costs will occur.¹¹⁹⁸

SCE responds that the increased costs in the Cloud and Perpetual License forecast for 2021 are to support the continued operation of legacy systems through 2021 (*i.e.*, business as usual) now that CSRP's planned implementation has been delayed from 2020 to 2021. SCE states that discontinuing support for these systems would significantly impact functions such as SCE's customer outreach, demand response programs, and T&D workforce time and work management.¹¹⁹⁹ SCE contends that these costs are not part of the CSRP implementation costs that have been removed from this proceeding.¹²⁰⁰

¹¹⁹⁶ *Id.* at 39, 49-50.

¹¹⁹⁷ Cal Advocates OB at 214-215.

¹¹⁹⁸ *Id.* at 215.

¹¹⁹⁹ SCE OB at 227.

¹²⁰⁰ *Ibid.*

With respect to its normalization adjustment, SCE argues that the Commission has recognized the normalization of costs as a well-established rate making principle. SCE notes that Cal Advocates does not oppose SCE's normalization proposals that result in a decrease in the TY, and that it would be inequitable to only approve normalization when the normalized forecast for the TY is lower than the calendar year forecast.¹²⁰¹ SCE states that it forecasts significant cost increases in 2022 and 2023 to account for the following: (1) Extension of mainframe operating software maintenance in 2022 that will be required through the CSRP stabilization period; (2) Customer Service Application decommissioning costs in 2022 and 2023; and (3) Third-party application support costs beginning in 2022 to cover "break fix," enhancement, and stabilization for CSRP on an ongoing basis.¹²⁰² SCE contends that absent normalization, there would be no mechanism for SCE to recover these expected costs.

We find that SCE has adequately justified its TY forecast. SCE provides detailed workpapers supporting its itemized forecast for Cloud and Perpetual License.¹²⁰³ Cal Advocates does not dispute the necessity of the listed items or the reasonableness of SCE's cost estimates for the items. There is no evidence that the Cloud and Perpetual License forecast includes costs for CSRP implementation that SCE is seeking in another proceeding. Moreover, given the delay in CSRP implementation until early 2021, SCE justifies why costs related Customer Service Application Decommissioning and third-party support for the CSRP Systems Applications and Products (SAP) platform were removed from

¹²⁰¹ Ex. SCE-17, Vol. 1 at 14.

¹²⁰² SCE OB at 229.

¹²⁰³ Ex. SCE-06, Vol. 1, Pt. 1AC WP at 3-15.

the 2021 forecast and deferred to 2022 and 2023, as well as why costs are expected to increase in 2022 for the extension of mainframe operating software maintenance that will be required through the CSRP stabilization period.¹²⁰⁴ Therefore, we find normalization to be reasonable in this instance and approve SCE's TY forecast of \$97.245 million.

26.2. Enterprise Technology Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast Enterprise Technology capital expenditures (nominal, \$000):¹²⁰⁵

Capital Expenditures	2019	2020	2021
Software Maintenance and Replacement	19,100	35,875	60,559
Technology Infrastructure Maintenance and Replacement	51,778	65,328	76,309
Total	70,878	101,203	136,868

Software and Infrastructure Maintenance expenditures include expenditures for Perpetual License and Application Refresh. These expenditures include investments in new technologies, refreshing major suites of software, and restructuring of SCE's software portfolio, as well as support for upgrading, configuring, and testing operating software tools, IT applications, and interfaces.¹²⁰⁶

¹²⁰⁴ Ex. SCE-06, Vol. 1, Pt. 1A at 39, 50.

¹²⁰⁵ Ex. SCE-06, Vol. 1, Pt. 1A at 30, Table IV-4; Ex. SCE-06, Vol. 1, Pt. 1AE at 54, Table IV-17; Ex. SCE-18, Vol. 1, Appendix A at A-93.

¹²⁰⁶ Ex. SCE-06, Vol. 1, Pt. 1A at 40-42, 51.

Technology Infrastructure Maintenance and Replacement expenditures include expenditures for Data Center Infrastructure; End User Computing Maintenance, Services, and Replacement; and Technology Replacement.¹²⁰⁷

Cal Advocates reviewed SCE's justification for the forecasts and historical spending, and does not oppose SCE's requests.¹²⁰⁸ We find reasonable and approve SCE's unopposed 2019-2021 capital expenditure forecasts.

27. OU Capitalized Software

SCE requests that the Commission approve the following 2019 recorded and 2020-2021 forecast for Operating/Organizational Unit (OU) capitalized software (nominal, \$000):¹²⁰⁹

Capital Expenditures	2019	2020	2021
Technology Solutions	97,604	91,827	98,000

OU capitalized software supports business capabilities across SCE's Business Planning Groups and enterprise-level systems. SCE's forecast capitalized software projects support Resiliency (Business Continuation and Physical Security); Customer Interactions (Customer Contacts and Customer Care Services); Distribution Grid; Enterprise Support (Legal and Enterprise Technology); Substation; Energy Procurement; and Generation.¹²¹⁰

Proposed software projects undergo SCE's governance process to review and confirm that investments are prudent and financially responsible. However,

¹²⁰⁷ Ex. SCE-06, Vol. 1, Pt. 1A at 66-71, 77-78, 81-83; Ex. SCE-06, Vol. 1, Pt. 1AE at 66-68, 70.

¹²⁰⁸ Cal Advocates OB at 218-219.

¹²⁰⁹ Ex. SCE-17, Vol. 1 at 3-4; Ex. SCE-18, Vol. 1, Appendix A at A-93 to A-94.

¹²¹⁰ The specific software projects SCE plans to execute are described in Ex. SCE-06, Vol. 1, Pt. 2A at Chs. II-VIII. Projects that fall within broader programs such as Grid Modernization, CSRP, or Cybersecurity are excluded from the OU capitalized software forecast and addressed in other forecasts. (Ex. SCE-06, Vol. 1, Pt. 2A at 2.)

most projects that are several years out typically have not gone through this governance process because the pace of technology change makes it difficult to predict what technology will be available in the future. As such, SCE has less information about projects beginning in 2021-2023 than it does about projects beginning prior to 2021. SCE therefore uses a hybrid forecast approach consisting of: (1) an itemized forecast and testimony for all projects over \$3 million that have forecast spending in 2019-2020; and (2) a portfolio-based forecast based on historical costs for forecast spending in 2021-2023.¹²¹¹ SCE also presents an itemized forecast for six projects beginning in the 2021-2023 period due to having a higher degree of certainty regarding the planned technology solution.¹²¹² In rebuttal testimony, SCE updated its 2019 forecast with the 2019 recorded capital expenditures.

Cal Advocates reviewed SCE's historical spending and status of its 2019 projects and does not oppose SCE's request.¹²¹³ No party disputes the need for the projects that SCE proposes to execute or SCE's cost estimates for the projects. SCE's forecast represents a temporary reduction relative to historical spend due to SCE's implementation of the CSRP in early 2021, which necessitates a temporary freeze on other systems.¹²¹⁴ We find SCE's requests to be adequately supported and approve SCE's requested 2019-2021 capital expenditures.

SCE also requests that the Commission find reasonable and approve the amounts SCE recorded over authorized in 2017 and 2018 for its capitalized

¹²¹¹ *Id.* at 19.

¹²¹² These six projects are: Digital Roadmap, Integrated Position & Risk Management, Human Resource Re-Platform, Virtual Data Hybrid Data Center, Enhance Control Room-Generator Network Redundancy, and Predictive Analytics for People & Devices. (*Id.* at 175, fn. 132.)

¹²¹³ Cal Advocates OB at 220.

¹²¹⁴ Ex. SCE-06, Vol. 1, Pt. 2A at 174-175.

software projects, \$8.230 million in 2017 and \$15.368 million in 2018.¹²¹⁵ In the 2018 GRC, the Commission determined that contingency amounts included in SCE's capitalized software projects forecasts were not recoverable as a forecast item but stated that "[i]f additional funds become necessary, SCE may seek to establish the necessity in the next GRC."¹²¹⁶ SCE provides an explanation of the business needs that resulted in the variances between the authorized and recorded amounts for 2017-2018.¹²¹⁷ No party disputes the need for the projects that were undertaken or the reasonableness of the costs. We find that SCE has adequately justified the variances and approve the recorded 2017 and 2018 amounts that were above authorized.

28. Enterprise Planning and Governance (Non-Insurance)

28.1. Financial Oversight and Transactional Processing

SCE forecasts TY O&M expenses of \$109.640 million for the following activities in its Financial Oversight and Transactional Processing BPE:¹²¹⁸

¹²¹⁵ *Id.* at 4-5.

¹²¹⁶ D.19-05-020 at 152.

¹²¹⁷ Ex. SCE-06, Vol. 1, Pt. 2A at 6-18

¹²¹⁸ Ex. SCE-17, Vol. 2 at 5, Table II-5; Ex. SCE-54 at 61 and 255. Insurance is also a part of this BPE but issues concerning insurance expense are discussed in a separate section below. SCE's forecast for this BPE presented in rebuttal testimony does not reflect errata to the Participant Credits and Charges forecast. Per the forecasts presented in the Joint Comparison Exhibit, the Participant Credit and Charges forecast totals \$18.825 million rather than the \$19.953 million presented in rebuttal testimony.

Activity	TY Forecast (\$000)
Accounting, Financial Compliance, and Financial Reporting	24,248
Vendor Discount and Other Miscellaneous Payments	(13,089)
Participant Credits and Charges	18,825
Third-Party Non-Energy Billing and Decommissioning Credits	(1,291)
Franchise Fees	80,947
Total	109,640

SCE's forecast reflects a \$4.677 million decrease from the forecast SCE originally proposed in its direct testimony due to SCE's acceptance of Cal Advocates' recommendations concerning: (1) Vendor Discount and Other Miscellaneous Payments; and (2) Participant Credits and Charges.¹²¹⁹

The only remaining disputed issue relates to SCE's 2021 forecast for Accounting, Financial Compliance, and Financial Reporting. SCE's TY forecast of \$24.248 million is based on 2018 recorded costs plus the following cost adjustments: (1) a \$1.119 million increase in non-labor costs relating to a one-time accounting change in 2018 that did not represent a permanent cost reduction; (2) a \$0.317 million increase in labor costs to address an understaffed and overstretched workforce; and (3) a \$0.620 million increase in non-labor costs related to improvement and/or enhancement projects spend.¹²²⁰

Cal Advocates recommends that the Commission adopt a forecast of \$22.164 million based on 2018 recorded costs. Cal Advocates argues that

¹²¹⁹ SCE OB at 231. TURN recommended a \$2.228 million reduction to Palo Verde participant charges but accepts SCE's revised forecast based on Cal Advocates' recommendation since it results in a lower forecast than TURN's recommendation. (TURN OB at 178.)

¹²²⁰ SCE OB at 232-233.

additional funding would defeat SCE's Operational Excellence efforts and the efficiencies achieved.¹²²¹

SCE's recorded 2018 costs for both labor and non-labor were lower compared to recorded 2017 costs.¹²²² SCE states that the cost savings through Operational Excellence initiatives were fully materialized in 2017¹²²³ and that the lower 2018 costs are attributable to other factors that will not be repeated or are not sustainable in the TY.

SCE's requested increase of \$1.119 million in non-labor costs relative to 2018 recorded costs is due to an accounting change that created a one-time timing difference in expense recording. SCE explains that this accounting change resulted in 2018 expenses being lower and 2019 expenses being higher than historical average spending levels.¹²²⁴

SCE explains that the lower labor costs it experienced in 2018 compared to 2017 were due to temporary unexpected employee turnover in 2018, which is not a permanent cost reduction.¹²²⁵ SCE states that it hired multiple temporary outside consultants in 2019 to address the challenges created by the shortage in labor.¹²²⁶ SCE also explains that the labor shortage in 2018 resulted in the temporary delay of continuous improvement-related spending.¹²²⁷

¹²²¹ Cal Advocates OB at 222-223.

¹²²² Ex. SCE-17, Vol. 2 at 6, Table II-6.

¹²²³ *Id.* at 8.

¹²²⁴ *Id.* at 7.

¹²²⁵ *Id.* at 7-8.

¹²²⁶ *Id.* at 8.

¹²²⁷ Ex. SCE-06, Vol. 2 at 13; Ex. SCE-17, Vol. 2 at 9.

SCE's requested labor costs for the TY are \$0.3 million lower than 2017 recorded costs and represent a 12 percent reduction compared to historical average spending from 2014-2018.¹²²⁸ SCE's requested non-labor costs for the TY are \$1.2 million lower than 2017 recorded costs and represent a 3 percent reduction compared to historical average spend from 2014-2018.¹²²⁹

The record does not reflect that SCE's reduced costs in 2018 are attributable to its Operational Excellence initiatives. Taking into account historical spending levels and SCE's explanation regarding the reasons for the lower 2018 costs, we find SCE's requested adjustments to 2018 recorded costs to be adequately justified and reasonable. Therefore, we approve SCE's TY forecast of \$24.248 million for Accounting, Financial Compliance, and Financial Reporting activities.

We also find reasonable and approve SCE's undisputed forecasts (which include SCE's acceptance of the two recommendations by Cal Advocates described above) for the other activities included in the Financial Oversight and Transactional Processing BPE. To the extent any of these forecasts vary depending on other forecasts adopted in this decision, they should be modified accordingly through the Results of Operations model.¹²³⁰

¹²²⁸ Ex. SCE-17, Vol. 2 at 8.

¹²²⁹ *Id.* at 6, Table II-6 and 9-10.

¹²³⁰ For example, the calculation of participant charges is dependent, in part, on the adopted O&M costs for Palo Verde. (TURN OB at 178.)

28.2. Legal

SCE's 2021 TY forecast for the Legal BPE is \$88.682 million for the following work activity areas: (1) Law (\$42.911 million); (2) Claims (\$32.601 million); and (3) Workers' Compensation (\$13.170 million).¹²³¹

Cal Advocates has reviewed and does not oppose SCE's requests. Cal Advocates notes that SCE's forecast for each work activity area approximates the base year and is in line with the 5-year average (2014-2018).¹²³²

We find reasonable and approve SCE's unopposed forecast of \$88.682 million for its Legal organization and activities.

28.3. Business and Financial Planning

SCE's Business and Financial Planning BPE consists of the following work activities: (1) Business Planning; (2) Corporate Services; (3) Modeling, Analysis, and Forecasting; and (4) Digital and Process Transformation.¹²³³

28.3.1. Business and Financial Planning O&M

SCE's TY O&M forecast for Business and Financial Planning is \$65.547 million, which is an approximately \$6.1 million increase relative to 2018 recorded costs.¹²³⁴ SCE states that this increase is primarily driven by Digital and Process Transformation work activities. SCE's forecasts for work activities in this BPE, other than for Digital and Process Transformation, are based on last year recorded costs or last year recorded costs with adjustments.¹²³⁵

¹²³¹ Ex. SCE-06, Vol. 2 at 50, Table IV-14.

¹²³² Cal Advocates OB at 226.

¹²³³ Ex. SCE-06, Vol. 2 at 75.

¹²³⁴ *Id.* at 75 and 78, Figure V-23.

¹²³⁵ *Id.* at 82-83, 88, and 93.

SCE initiated Digital and Process Transformation activities at the end of 2018 to build upon its prior Operational Excellence and X-Change program efforts.¹²³⁶ SCE's goal with respect to this work is to fully utilize data and technology to improve decision making, manage risk proactively, and enhance customer activities.¹²³⁷

SCE's forecast for Digital and Process Transformation is \$8.013 million, which is an increase of \$6.392 million relative to 2018 recorded costs.¹²³⁸ Due to the unavailability of historical data, SCE utilized an itemized forecast methodology based on the forecast level of staffing necessary to support the volume of initiatives that will be undertaken in 2021.¹²³⁹ Non-labor employee expenses, supplies, and training costs are a function of the employee headcount.¹²⁴⁰ Other non-labor expenses include third-party software development costs and software, hardware, and implementation costs, which SCE derived by utilizing industry benchmarks and historical costs from similar technology work components implemented by SCE.¹²⁴¹

SCE's TY O&M forecast for Business and Financial Planning is unopposed. We find reasonable and adopt the unopposed forecast.

¹²³⁶ *Id.* at 94 and 100-101.

¹²³⁷ *Id.* at 94.

¹²³⁸ *Id.* at 94, Figure V-27. The total increase for the Business and Financial Planning is less than \$6.392 million because SCE forecasts a decrease for other work activities in the BPE.

¹²³⁹ *Id.* at 101.

¹²⁴⁰ *Id.* at 102.

¹²⁴¹ *Ibid.*

28.3.2. Business and Financial Planning Capital

SCE's 2019-2021 capital expenditure forecast for Business and Financial Planning is \$16.047 million.¹²⁴² The capital expenditures are for Digital Accelerator, which is one of the teams that spearheads Digital and Process Transformation. SCE states the capital investment is needed to fund the planning, development, and implementation of digital solutions, including costs for labor, hardware, software licenses, and third-party software development.¹²⁴³ We find reasonable and adopt SCE's unopposed forecast.

28.4. Supply Chain Management

28.4.1. Supply Chain Management O&M

SCE's TY forecast for Supply Chain Management (SCM) O&M is \$6.901 million, consisting of \$3.480 million for Mailing Services and Graphics Production and \$3.422 million for its Supplier Diversity and Development (SDD) department.¹²⁴⁴

SCE's O&M forecast for Mailing Services and Graphics Production is unopposed. SCE bases this forecast on recorded 2018 costs (\$4.170 million) less the costs associated with outside courier services and company vehicles.¹²⁴⁵ The reductions are due to operational improvements, decreasing delivery frequency, and reduced requirements for forms and printing. We find reasonable and approve this forecast.

SCE's O&M forecast for SDD is opposed by NDC. SDD manages SCE's efforts to contract with, and provide outreach and training to, Diverse Business

¹²⁴² Ex. SCE-17, Vol. 2 at 4, Table I-4.

¹²⁴³ Ex. SCE-06, Vol. 2 at 102-104.

¹²⁴⁴ Ex. SCE-17, Vol. 2 at 38, Table IV-13.

¹²⁴⁵ Ex. SCE-06, Vol. 2 at 116.

Enterprises (DBEs) in compliance with GO 156.¹²⁴⁶ SCE's SDD forecast of \$3.422 million consists of \$1.174 million in labor expense and \$2.248 million in non-labor expense.¹²⁴⁷ SCE's forecast is based on 2018 recorded costs (\$3.240 million) plus an increase of \$194,000 in labor expense and a decrease in \$12,000 in non-labor expense.¹²⁴⁸ SCE argues that the increase in labor expense is warranted to retain an employee hired in 2019 so that SDD can return to a full staffing level of nine FTEs and to include one additional position in 2021 to manage an expanded focus on small business programming and outreach.¹²⁴⁹

NDC opposes SCE's requested increase in labor costs and recommends that the 2021 forecasts for both labor and non-labor be based on 2018 recorded costs. NDC argues that SCE provides an inadequate explanation for why prior staffing levels are necessary or appropriate and that 2018 recorded costs are sufficient to sustain SDD's performance level. NDC notes that SDD exceeded its 40 percent DBE contracting goal every year since 2014 despite the fact that it did not have nine FTEs in many of those years.¹²⁵⁰ NDC also argues that SCE has not presented any specific plans or goals to expand SDD program offerings or improve performance that would warrant additional funding.¹²⁵¹ While NDC supports the creation of a new position focused on meeting the needs of small

¹²⁴⁶ *Id.* at 105.

¹²⁴⁷ *Id.* at 115.

¹²⁴⁸ *Ibid.*; SCE OB at 236.

¹²⁴⁹ SCE OB at 236.

¹²⁵⁰ NDC OB at 22.

¹²⁵¹ *Id.* at 24.

businesses, NDC argues that SCE's 2018 recorded costs should be sufficient to account for this additional position.¹²⁵²

SBUA supports SCE's request for funding for one additional FTE to focus on small business programing and outreach.¹²⁵³

We find that SCE has not adequately justified its requested increase from 2018 recorded costs to revert to a staffing level of nine FTEs but find adequate justification for an additional small business position.

Although SCE states that the full staffing level is nine FTEs, the record supports finding SDD has been able to sustain its performance level even when it did not have nine FTEs for extended periods of time. SDD had seven to eight FTEs in 2017, 2018, and the majority of 2019.¹²⁵⁴ SDD exceeded the 40 percent DBE contracting goal every year since 2014 and was also able to make program enhancements between 2016-2019 when it did not have nine FTEs for much of this period.¹²⁵⁵ Moreover, excluding the position focusing on small businesses discussed below, SCE does not demonstrate that it has plans for new program goals or enhancements that would result in increased costs or warrant additional funding.

SCE's recorded costs also do not support an increase in labor expense. SCE's labor costs for SDD have declined consistently year over year since 2014.¹²⁵⁶ Furthermore, SCE underspent its previously authorized budget. In the

¹²⁵² *Id.* at 26-27.

¹²⁵³ SBUA RB at 4.

¹²⁵⁴ Ex. NDC-03, SCE Response to Data Request Set NDC-SCE-007, Question 05.b Revised. SCE states that its staffing levels were less than nine FTEs in 2017 and 2018 due to attrition from unplanned retirements, separations, and internal movement. (Ex. SCE-17, Vol. 2 at 39-40.)

¹²⁵⁵ NDC OB at 22; Ex. SCE-17, Vol. 2 at 41-42.

¹²⁵⁶ Ex. NDC-01 at 33.

2018 GRC, the Commission authorized \$3.618 million for SDD O&M. SCE's 2018 recorded expense was \$3.240 million. According to SCE, the underspend of \$378,000 was primarily due to decreased labor costs.¹²⁵⁷ SCE's 2018 level of spending does not appear to be anomalous given that SCE had similar staffing levels for all of 2017 and most of 2019.¹²⁵⁸

With respect to SCE's request for an additional position to focus on small business programming and outreach, both NDC and SBUA support the creation of this position. However, NDC argues that SCE has failed to justify its request for additional funding. NDC argues that the Commission should authorize the small business position with 2018 recorded costs due to: (1) SCE's failure to provide a breakdown of costs for the position, (2) the potential continuation of the five-year trend in decreasing labor costs, and (3) the \$12,000 savings from using the 2018 recorded as opposed to SCE's forecast non-labor costs.¹²⁵⁹

We agree with the parties that, especially given the additional challenges facing small businesses due to the COVID-19 pandemic, it is reasonable for SCE to add a position focused on small business programming and outreach. However, we do not find that recorded 2018 costs would be sufficient to account for the additional position. NDC argues that the linear trending forecast model shows 2021 costs potentially being \$400,000 below 2018 costs.¹²⁶⁰ We find it unlikely that labor costs will continue to trend downward as modeled. Although costs decreased between 2017 and 2018, the difference was a mere \$11,000 and

¹²⁵⁷ Ex. SCE-06, Vol. 2 at 113.

¹²⁵⁸ Ex. NDC-03, SCE Response to Data Request Set NDC-SCE-007, Question 05.b Revised.

¹²⁵⁹ NDC OB at 26-27.

¹²⁶⁰ *Id.* at 26.

there was not a decrease in staffing level.¹²⁶¹ Based on historic staffing levels, we do not find evidence to suggest that SDD can sustain its performance level with less than seven to eight FTEs. The addition of NDC's proposed \$12,000 savings in non-labor costs would still be insufficient to fund an additional position.

There is some merit to NDC's argument that SCE has failed to present a cost breakdown for the new position. However, given that SCE's requested increase is for two additional positions, both of which appear to be Program Manager positions,¹²⁶² we find half of SCE's requested labor increase, or \$97,000, to be a reasonable approximation of the cost to fund the small business position. Therefore, we adopt an SDD labor forecast of \$1.077 million based on 2018 recorded costs of \$0.980 million, plus an increase of \$97,000 to account for the additional small business position. We direct SCE to report on SDD's small business programming and outreach efforts undertaken during this GRC cycle in its next GRC.

NDC also recommends use of 2018 non-labor recorded costs, which is \$12,000 more than SCE forecast, as the basis for the TY non-labor forecast. NDC argues that the \$12,000 could be used, in part, to fund the small business position. We see no reason to adopt a forecast that exceeds SCE's forecast, especially given that we are approving additional funding for the small business position. We find reasonable and adopt SCE's forecast of \$2.248 million for SDD non-labor expense.

¹²⁶¹ Ex. NDC-01 at 33; Ex. NDC-03, SCE Response to Data Request Set NDC-SCE-007, Question 05.b Revised.

¹²⁶² Ex. NDC-03, SCE Response to Data Request Set NDC-SCE-007, Question 05.b Revised; Ex. SCE-17, Vol. 2 at 42.

28.4.2. Supply Chain Management Capital

SCE's 2019-2021 capital expenditure forecast for SCM is \$1.047 million.¹²⁶³ SCM is responsible for procuring, storing, and delivering materials to support the activities of all of SCE's Operating Units. SCE's forecast capital expenditures include warehouse infrastructure improvements, hardware for technology applications, and materials handling equipment.¹²⁶⁴ We find reasonable and adopt SCE's unopposed forecast.

29. Insurance

29.1. Liability Insurance (Wildfire)

Consistent with prior years, SCE continues to purchase approximately \$1 billion of wildfire insurance coverage to protect customers from the financial exposure of third-party legal claims resulting from wildfires alleged to be caused by SCE infrastructure. SCE argues that it is prudent for it to maintain \$1 billion in coverage since that is the level of liability SCE would need to incur before accessing the Wildfire Fund created by AB 1054.¹²⁶⁵ In addition, SCE argues that this level of coverage is beneficial to and necessary for customers because: (1) it protects customers from third-party claims related to wildfires pursued under the inverse condemnation doctrine, under which SCE will be held strictly liable for resulting damages even when SCE is not at fault; and (2) as recognized by Governor Newsom's June 21, 2019 official report on catastrophic wildfires, stabilizing the financial health of California's utilities is essential to enable them

¹²⁶³ Ex. SCE-17, Vol. 2 at 4, Table I-4.

¹²⁶⁴ Ex. SCE-06, Vol. 2 at 117-118.

¹²⁶⁵ SCE OB at 237.

“to provide safe, affordable and reliable energy, ensure fair compensation for wildfire victims, and protect ratepayers from massive rate spikes.”¹²⁶⁶

SCE forecasts TY wildfire liability insurance expense of \$623.804 million.¹²⁶⁷ SCE recognizes that this is significantly higher than previous years but argues that this is not unexpected given the increased risks facing electric utilities from wildfires and the tightening of the markets for wildfire liability insurance.¹²⁶⁸ Given climbing wildfire liability insurance prices, SCE contends that its recorded expense is not an appropriate basis on which to forecast TY 2021 expenses.¹²⁶⁹ Rather, SCE uses a forecast developed by its primary insurance broker, Marsh USA Inc. (Marsh), based on expected insurance market trends as well as SCE’s specific loss history. SCE notes that this is the forecast methodology SCE has used consistently in prior GRCs, and which the Commission has accepted consistently.¹²⁷⁰

Cal Advocates recommends that wildfire liability insurance expense be shared between ratepayers and shareholders based on a 75 percent/25 percent allocation, which results in a \$155.951 million reduction to SCE’s request. Cal Advocates argues that although wildfire liability insurance protects ratepayers, it also protects and benefits shareholders. Cal Advocates also notes that increasing insurance premiums can be attributed to wildfires caused by utility equipment.

¹²⁶⁶ *Id.* at 237-238 quoting June 21, 2019 Governor Newsom’s Strike Force Progress Report on Catastrophic Wildfires, Climate Change and Our Energy Future at p. 7.

¹²⁶⁷ SCE OB at 238.

¹²⁶⁸ *Ibid.*

¹²⁶⁹ Ex. SCE-06, Vol. 2 at 33.

¹²⁷⁰ Ex. SCE-17, Vol. 2 at 26.

TURN makes the following recommendations: (1) wildfire liability insurance expenses should be allocated 50/50 between ratepayers and shareholders since wildfire risk has potential financial consequences for both; (2) SCE's 2021 forecast of \$623.8 million is inadequately supported and the Commission should instead adopt the 2019 forecast cost (\$410.6 million) as the forecast for 2021; and (3) the Commission should decline to take any position on alternative risk transfer instruments until SCE establishes the reasonableness of any alternative option to conventional insurance.

29.1.1. Ratepayer and Shareholder Allocation

As acknowledged by both TURN and Cal Advocates, their proposals to allocate the costs of wildfire liability insurance premiums to both ratepayers and shareholders would depart from well-established Commission precedent. The Commission routinely authorizes ratepayer recovery of wildfire liability insurance costs through GRCs without requiring cost sharing between ratepayers and shareholders as long as the utility has demonstrated that its forecast costs are reasonable.¹²⁷¹ The Commission also regularly authorizes ratepayer recovery of incremental wildfire liability insurance costs without shareholder cost sharing unless there are findings of utility imprudence.¹²⁷²

We do not find that TURN or Cal Advocates presents any arguments that would warrant a departure from this well-established precedent. The purpose of liability insurance is to protect the utility and its customers from various third-party claims, including those related to inverse condemnation and negligence.¹²⁷³ Although we recognize that liability insurance mitigates risks for

¹²⁷¹ D.20-09-024 at 43; D.12-11-051 at 512-513; D.09-03-025 at 166; Resolution E-4994 at 6.

¹²⁷² See, e.g., D.20-09-024; Resolution E-4994.

¹²⁷³ D.20-09-024 at 44.

shareholders, we continue to find that liability insurance is a standard cost of doing business that is primarily designed to benefit ratepayers.¹²⁷⁴ The Commission generally permits rate recovery for costs related to wildfire liability claims absent a finding of utility imprudence, and therefore, it is ratepayers that face the most risk in the event of uninsured claims.

TURN argues that it is equitable to allocate costs to shareholders because wildfire liability insurance mitigates “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.”¹²⁷⁵ Although TURN is correct that shareholders face such risk, we do not find it reasonable to change the traditional cost allocation framework based on the risk that SCE’s future actions could be found to be imprudent. We cannot determine at this time whether any of SCE’s actions with respect to a future wildfire event will be found to be imprudent and we decline to preemptively disallow costs based on that possibility. If the Commission finds that there is imprudence, the Commission has the authority to order other remedies, including requiring shareholders to pay for the cost of settlements or judgments. Moreover, if the Commission finds that there is utility wrongdoing, it has the authority to impose fines or penalties on shareholders.

Cal Advocates claims that shareholders receive substantial and valuable benefits by liability insurance. However, Cal Advocates does not explain what these shareholder benefits are other than a reference to “intangible benefits ... because of the greater financial stability that it provides for SCE.”¹²⁷⁶ We do not

¹²⁷⁴ *Id.* at 49-50.

¹²⁷⁵ TURN OB at 179-180.

¹²⁷⁶ See Cal Advocates OB at 231-232 citing SCE response to data request Pub Adv-SCE-057-LMW, Q.7.a.

find that the intangible benefits referenced by Cal Advocates provide sufficient justification for shareholder allocation of these costs. As explained above, absent a finding of utility imprudence, uninsured wildfire liability claims are generally recovered from ratepayers.

Cal Advocates also argues that, although “in the past ... ratepayers were traditionally responsible for insurance premiums,” the Commission should require shareholders to share in the insurance premiums due to the fact that “the insurance market has evolved and changed dramatically for utilities.”¹²⁷⁷ It is undisputable that the insurance market for wildfire liability premiums has changed in recent years but Cal Advocates fails to explain why these market changes would justify an allocation of insurance costs to SCE’s shareholders. Cal Advocates argues that the substantial increases in insurance premiums are attributable to wildfires caused by utility equipment. However, with the exception of the Thomas Fire, all of the wildfires that Cal Advocates references did not occur in SCE’s territory.¹²⁷⁸ Therefore, it is unclear to what extent SCE’s specific loss history contributed to the increase in premiums. Moreover, in the absence of any finding of utility imprudence or wrongdoing, it is unclear to what extent any increase in premiums due to SCE’s specific loss history should be allocated to shareholders.

We also note that all three major energy utilities operate under the same cost allocation framework for these costs, including the cost allocation framework set forth in AB 1054.¹²⁷⁹ SCE’s wildfire insurance costs have

¹²⁷⁷ Cal Advocates OB at 228.

¹²⁷⁸ *Id.* at 230-231.

¹²⁷⁹ SCE asserts that the Legislature enacted the mandate in AB 1054 that utilities carry \$1 billion in wildfire liability insurance “with the understanding that ‘[u]tilities generally buy

increased significantly in recent years, decreasing the cost effectiveness of the insurance as a way to manage risk. If costs continue to escalate, at some point, insurance may no longer be cost effective and consideration of alternative methods of managing risk or allocating costs may be warranted. However, as we recently stated in D.20-09-024, “it may be inefficient to change the Commission’s cost recovery approach for ratepayer payment of premiums for a single utility without regard for how other major utilities may be impacted.”¹²⁸⁰ Moreover, we do not find that any party has identified any facts or circumstances that would warrant singling out SCE for different ratemaking treatment.

Given the above considerations, we do not find that changes to the traditional cost allocation framework for wildfire liability insurance costs are justified in this GRC. Therefore, we authorize SCE to recover the wildfire liability insurance cost forecast we adopt in this decision in rates without allocation of any of these costs to shareholders.

29.1.2. Reasonableness of Forecast

Parties do not dispute SCE’s contention that it is prudent for SCE to maintain \$1 billion in wildfire liability insurance coverage during this rate case period. As explained by SCE, this is consistent with the level of coverage SCE has maintained in prior years and what AB 1054 requires in order for SCE to access the Wildfire Fund.¹²⁸¹

commercial insurance to cover costs related to unexpected events such as wildfires’ and that ‘*[t]he costs of the premiums utilities pay for this insurance are passed on to ratepayers.*’” (SCE OB at 252 quoting AB 1054 bill analysis, original italics.)

¹²⁸⁰ D.20-09-024 at 46.

¹²⁸¹ SCE OB at 237.

TURN, however, disputes SCE's forecast of \$623.8 million as the cost of obtaining \$1 billion of coverage for the TY. TURN argues that SCE's overall showing is inadequate to establish the reasonableness of the forecast amount. According to TURN, SCE's testimony does not explain how SCE arrived at the \$623.8 million figure and the sole supporting document, a letter from SCE's insurance broker, provides only the most minimal information.¹²⁸² TURN instead recommends that the Commission adopt SCE's 2019 forecast of \$410.6 million as the 2021 TY forecast.¹²⁸³

There is no question that SCE's 2021 TY forecast of \$623.8 million is a significant increase from previously authorized and recorded costs. In the 2018 GRC, the Commission authorized \$92.4 million for total liability insurance expense (combined wildfire and non-wildfire) for the TY.¹²⁸⁴ SCE recorded \$236.9 million in wildfire liability insurance costs for 2018.¹²⁸⁵ The requested increase accounts for a significant percentage of the \$1.288 billion, or 20.26 percent, increase over existing base rates that SCE is requesting in this GRC proceeding.¹²⁸⁶

SCE's forecast is based on the expert opinion of SCE's insurance broker, Marsh, which forecast the premiums based on "expected insurance market trends as well as SCE's specific loss record."¹²⁸⁷ SCE did not present any further

¹²⁸² TURN OB at 183-184.

¹²⁸³ *Id.* at 185.

¹²⁸⁴ Ex. SCE-06, Vol. 2 at 35, Figure III-9.

¹²⁸⁵ *Ibid.*

¹²⁸⁶ SCE OB at 3.

¹²⁸⁷ Ex. SCE-06, Vol. 2 at 33.

detailed information regarding how SCE's insurance broker derived the forecast.¹²⁸⁸

The Commission has adopted insurance expense forecasts developed by SCE's broker in the past. In this instance, however, given the magnitude of the requested forecast, we find SCE's showing to be inadequate. As previously explained by the Commission: "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."¹²⁸⁹ We recognize that various factors have resulted in increasing premium costs in recent years and that an increase over previously authorized insurance expense would be reasonable. However, because SCE does not provide sufficient details regarding the basis of its forecast, we are unable to assess whether the \$623.8 million requested by SCE constitutes a reasonable increase.

SCE argues that its forecast is in line with recent actual expenses as demonstrated in its 2018 Z-Factor and 2019 Wildfire Expense Memorandum Account (WEMA) proceedings.¹²⁹⁰ However, SCE's TY forecast is significantly higher than the combined wildfire insurance costs that the Commission has authorized for recovery in SCE's 2018 GRC, 2018 Z-Factor filing, and 2019 WEMA application for coverage during 2018-2020.

- In SCE's 2018 GRC, the Commission authorized \$54.4 million in wildfire insurance expense for April 3, 2018

¹²⁸⁸ See TURN OB at 183-184.

¹²⁸⁹ D.18-07-025 at 6 quoting D.02-08-064 at 5-8.

¹²⁹⁰ Ex. SCE-17, Vol. 2 at 26 citing Advice Letter 3768-E and A.19-07-020.

through December 31, 2018, \$77.1 million for 2019, and \$78.8 million for 2020.¹²⁹¹

- In Resolution E-4994, the Commission granted SCE's request for Z-factor recovery of \$107.2 million in incremental wildfire liability expense for coverage in 2018.¹²⁹²
- In SCE's 2019 WEMA proceeding, SCE asserted that it had incremental wildfire insurance expense of \$42.8 million for the period between April 3 and December 31, 2018, \$315.0 million for 2019, and \$151.2 million for the period between January 1 and June 30, 2020.¹²⁹³ The Commission authorized SCE to recover the CPUC-jurisdictional amount of these incremental wildfire insurance expenses.¹²⁹⁴

Therefore, review of these expenses does not demonstrate the reasonableness of SCE's request of \$623.8 million for a single year of coverage.

SCE acknowledges that wildfire liability insurance costs are "significant and difficult to forecast accurately."¹²⁹⁵ Due to these factors and the inadequate justification for SCE's forecast, we find it reasonable to adopt a TY forecast of \$460.0 million, which is in line with amounts the Commission has found to be

¹²⁹¹ Ex. SCE-06, Vol. 2, Appendix A at A-26, Table IV-3. In the 2018 GRC, the Commission adopted a forecast for general liability insurance expense, which included costs related to both wildfire and non-wildfire insurance expense. To calculate the amount authorized for wildfire insurance expenses, SCE reduces the amount authorized for general liability insurance by 20 percent and adds in the full amount authorized for supplemental wildfire reinsurance. (*Id.* at A-26.)

¹²⁹² Resolution E-4994 at 12, OP 1. The total cost for the incremental insurance coverage was \$124.5 million of which the CPUC-jurisdictional amount was \$117.156 million. (*Id.* at 3.) SCE's Z-factor mechanism includes a \$10 million deductible for each Z-factor event. (*Id.* at 3-4.)

¹²⁹³ Ex. SCE-06, Vol. 2, Appendix A at A-25, Table IV-1 and A-27, Table IV-4.

¹²⁹⁴ *Ibid.*; D.20-09-024 at 70, OP 1.

¹²⁹⁵ Ex. SCE-07, Vol. 1A at 34.

reasonable and authorized for 2020.¹²⁹⁶ Given the volatility and uncertainty of these costs, as discussed further below, we find it reasonable to establish a one-way balancing account to ensure that any overcollection is returned to ratepayers. We also continue to authorize SCE to seek rate recovery of any costs in excess of the forecast through the WEMA.

29.1.3. Alternative Risk Transfer Instruments

SCE proposes to use alternative risk transfer instruments such as catastrophe bonds or funded self-insurance at times when those alternatives provide better or less expensive coverage than traditional wildfire liability insurance.¹²⁹⁷ SCE states that it would only engage in such transactions if they could fill capacity at a lower cost than market-priced insurance and reinsurance or if no such capacity were available from the traditional markets.¹²⁹⁸

TURN argues that SCE has not provided adequate information about these alternatives, such as the potential costs and benefits, that would enable the Commission to assess their reasonableness. TURN argues that the Commission should not authorize SCE's use of alternative risk transfer instruments until SCE has made an adequate reasonableness showing.¹²⁹⁹

¹²⁹⁶ In SCE's 2018 GRC, the Commission authorized \$78.8 million in wildfire insurance premium expense for 2020. (Ex. SCE-06, Vol. 2, Appendix A at A-26, Table IV-3.) In SCE's 2019 WEMA proceeding, the Commission authorized SCE to recover the CPUC-jurisdictional amount of its \$151.2 million in incremental wildfire insurance premium expense for the period between January 1 through June 30, 2020. (Ex. SCE-06, Vol. 2, Appendix A at A-25, Table IV-1 and A-27, Table IV-4; D.20-09-024 at 70, OP 1.) Based on these amounts, SCE's wildfire insurance expense for half of 2020 (January 1-June 30, 2020) totaled approximately \$230.0 million.

¹²⁹⁷ SCE OB at 247.

¹²⁹⁸ *Id.* at 248.

¹²⁹⁹ TURN OB at 186-187.

SCE has not set forth any specific proposal for the Commission's review, and therefore, we cannot make a finding that SCE's use or potential use of any alternative risk transfer instrument is reasonable. For example, SCE states that it may self-insure when it determines that it is uneconomic to purchase liability insurance for some portion of its wildfire exposure as supported by actuarial analysis.¹³⁰⁰ SCE does not indicate that it has yet made any such determination and has not presented any actuarial or other analysis for the Commission to review at this time.

We recognize that, under certain circumstances, alternative risk transfer instruments may be a more cost-effective way to manage risk. SCE's recorded wildfire insurance expenses demonstrate that premium prices have significantly increased in recent years, making traditional wildfire liability insurance increasingly less cost-effective. Therefore, we do not preclude SCE from relying on such instruments when circumstances warrant. The use of such instruments is not novel. SCE points out that both SDG&E and PG&E have used catastrophe bonds in recent years.¹³⁰¹ Moreover, in PG&E's recent GRC, the Commission adopted a settlement that authorized PG&E to use self-insurance if the availability of competitively priced insurance in the market is limited.¹³⁰²

SCE is directed to report on any use of alternative risk transfer instruments during this rate case period, including the circumstances that warranted such use, in its next GRC for the Commission's review. If SCE's use of alternative risk transfer instruments results in costs in excess of the adopted forecast for wildfire

¹³⁰⁰ Ex. SCE-06, Vol. 2 at 41.

¹³⁰¹ Ex. SCE-17, Vol. 2 at 27.

¹³⁰² D.20-12-005 at 250.

liability insurance expense, SCE is required to demonstrate the reasonableness of any above-forecast costs in order to obtain rate recovery through the WEMA.

29.1.4. Risk Management Balancing Account

“Because of extreme volatility and uncertainty of wildfire liability insurance costs,” SCE proposes a new two-way balancing account (the Risk Management Balancing Account or RMBA) to capture the difference between SCE’s actual and authorized wildfire liability insurance expense.¹³⁰³ SCE argues that because it is necessary for SCE to maintain at least \$ 1 billion in coverage, it is unreasonable to require SCE to continue to carry potential above-forecast costs for several years prior to cost recovery.¹³⁰⁴

Cal Advocates does not oppose the proposed RMBA contingent upon the adoption of its proposal for 75 percent ratepayer/25 percent shareholder allocation of the wildfire insurance premiums.¹³⁰⁵

SCE is currently able to track and seek recovery of above-authorized wildfire liability insurance costs through the WEMA. TURN argues that adoption of the RMBA would eliminate the reasonableness review process associated with the WEMA for the far lesser compliance review that would occur in the ERRA. Given that SCE has indicated that it may rely on alternative risk transfer instruments for the first time and given that the insurance expense

¹³⁰³ Ex. SCE-06, Vol. 2 at 41. SCE proposes to transfer any over- or under-collection in the RMBA to the distribution sub-account in the Base Revenue Requirement Balancing Account (BRRBA) as of December 31st to be returned to or recovered from customers and that the recorded operation of the RMBA be reviewed for compliance in its annual ERRA review proceeding. (Ex. SCE-07, Vol. 1A2 at 35.)

¹³⁰⁴ SCE OB at 302.

¹³⁰⁵ Cal Advocates OB at 232-233.

forecast has increased significantly since the last GRC, TURN argues that the higher level of scrutiny associated with the WEMA is warranted.¹³⁰⁶

Due to the volatility and uncertainty of wildfire liability costs, we find that it is reasonable for SCE to establish a balancing account for wildfire liability insurance costs for this GRC period. However, we agree with TURN that a higher level of scrutiny is warranted for any rate recovery above forecast costs. In a recent decision addressing SCE's 2019 WEMA application, the Commission noted the need for greater scrutiny of these costs and required SCE to provide additional information in future WEMA applications, including information regarding SCE's history of wildfire insurance premiums paid and value of associated coverage, the procurement process, status of insurance markets, consideration of alternatives, and history of uninsured losses.¹³⁰⁷ An annual compliance review of the RMBA in the ERRA proceeding, as proposed by SCE, would not entail a reasonableness review that considers such information. Therefore, we deny SCE's proposed two-way RMBA.

Rather, we authorize SCE to establish the RMBA as a one-way balancing account with any overcollection returned to ratepayers.¹³⁰⁸ The wildfire liability insurance forecast we adopt in this decision is a significant increase from the amount authorized in the prior GRC and SCE acknowledges that these costs are

¹³⁰⁶ TURN OB at 253-255.

¹³⁰⁷ D.20-09-024 at 53-54.

¹³⁰⁸ SCE shall include the RMBA balance in its year-end consolidated revenue requirement and rate change advice letter. SCE shall annually transfer any over-collection in the RMBA to the distribution sub-account in the BRRBA as of December 31st to be returned to customers. The RO Model incorrectly used a labor allocator to allocate wildfire insurance costs between distribution and generation customers and has been updated to recover these costs only from distribution customers.

volatile and uncertain. Adoption of the one-way balancing account will protect ratepayers from any forecast errors.

By the same token, given the uncertainty of these costs and since we find that it is reasonable for SCE to maintain at least \$1 billion in wildfire liability insurance coverage, we do not preclude SCE from seeking future rate recovery of costs in excess of the adopted forecast that are required to maintain this coverage level. SCE may continue to track and seek recovery of any wildfire liability insurance costs above the adopted forecast through the WEMA. This will enable the Commission to review the reasonableness of any costs above the forecast amount, including SCE's use of any alternative risk transfer instruments.

29.2. Liability Insurance (Non-Wildfire)

SCE forecasts \$35.851 million for non-wildfire liability insurance expense in TY 2021.¹³⁰⁹ SCE's non-wildfire liability insurance programs include general liability, fiduciary liability, directors and officers (D&O), workers compensation, nuclear liability, cyber liability, and miscellaneous liability insurance and surety bonds. SCE's forecast is based on "forward-looking guidance from its insurance broker" consistent with prior GRCs.¹³¹⁰

Cal Advocates recommends a 10 percent, or \$3.585 million, reduction to the forecast because SCE's recorded non-wildfire liability insurance was 10 percent below SCE's forecast for 2019.¹³¹¹

We do not find Cal Advocates' recommendation to be justified because we do not find evidence that SCE's broker systematically overestimates the liability

¹³⁰⁹ Ex. SCE-17, Vol. 2 at 29, Table III-11.

¹³¹⁰ *Id.* at 28.

¹³¹¹ Ex. PAO-10 at 22.

insurance forecast.¹³¹² Therefore, we find reasonable and approve SCE's forecast based on its insurance broker's projections.

29.3. Property Insurance

SCE forecasts \$20.462 million for property insurance expense in TY 2021.¹³¹³ SCE's forecast is based on "forward-looking guidance from its insurance broker" consistent with prior GRCs.¹³¹⁴ Cal Advocates recommends a 6 percent, or \$1.228 million, reduction to the forecast because SCE's recorded property insurance was 6 percent below SCE's forecast for 2019.¹³¹⁵

We do not find Cal Advocates' recommendation to be justified because we do not find evidence that SCE's broker systematically overestimates the property insurance forecast.¹³¹⁶ Therefore, we find reasonable and approve SCE's forecast based on its insurance broker's projections.

29.4. Proposed Accelerated Recovery of Wildfire Insurance-Related Regulatory Asset

In the 2015 and 2018 GRCs, the Commission authorized SCE to capitalize a portion of its wildfire-related insurance premiums.¹³¹⁷ SCE records the capitalized premiums as a regulatory asset with a forecast balance of

¹³¹² See Ex. SCE-17, Vol. 2 at 29-30.

¹³¹³ *Id.* at 31, Table III-12.

¹³¹⁴ *Id.* at 30.

¹³¹⁵ Ex. PAO-10 at 22-23.

¹³¹⁶ Ex. SCE-17, Vol. 2 at 31.

¹³¹⁷ The Commission authorized this ratemaking treatment because, prior to 2018, SCE's wildfire coverage had generally been included in combined liability insurance. (Ex. SCE-06, Vol. 2 at 47.) The costs of wildfire insurance premiums have increased dramatically in recent years and starting in 2018, the market for wildfire insurance mandated wildfire-specific policies and premiums (not combined ones). (*Ibid.*)

approximately \$95 million at the start of the 2021 TY.¹³¹⁸ The associated rate recovery is expected to occur over a 23.4-year period.¹³¹⁹

SCE proposes to recover the regulatory asset faster over this GRC cycle. Because the full unrecovered premiums would not be expensed immediately, SCE proposes to continue earning a return on the regulatory asset for the period of recovery. SCE argues its proposal is consistent with FERC's requirement that the cost of stand-alone wildfire-related insurance premiums be expensed rather than capitalized.¹³²⁰ SCE argues its proposal is also consistent with the accounting treatment SCE is seeking for wildfire insurance premiums in this GRC and recorded wildfire premiums in its WEMA.¹³²¹ SCE contends that inconsistent accounting treatment across jurisdictions and time periods results in inefficiencies and increased costs.

Maintaining the status quo would result in SCE recovering approximately \$50.6 million in rates over the four-year 2021 GRC cycle (approximately \$13.3 million in 2021, \$12.9 million in 2022, \$12.5 million in 2023, and \$12.1 million in 2024).¹³²² Because SCE seeks to continue earning a return during the period of recovery, SCE's proposal would result in SCE collecting a total of

¹³¹⁸ *Ibid.*

¹³¹⁹ Ex. SCE-17, Vol. 2 at 33, fn. 67.

¹³²⁰ SCE OB at 256 citing FERC Order on Compliance Filing, issued August 3, 2012, to SDG&E in Docket No. ER11-4318-001. A copy of the FERC Order (*San Diego Gas & Elec. Co.* (2012) 140 FERC ¶ 61,108) is included as Appendix B to Ex. SCE-17, Vol. 2.

¹³²¹ SCE OB at 258.

¹³²² Ex. SCE-17, Vol. 2, Appendix A at A-1 to A-2.

\$114.8 million over the four-year 2021 GRC cycle.¹³²³ SCE's proposal would result in an increase of approximately \$19 million in the TY.¹³²⁴

Cal Advocates and TURN oppose SCE's proposal. They both argue the FERC Order does not mandate a change in the previously adopted ratemaking treatment and that SCE's proposal does not provide any benefit to ratepayers.¹³²⁵ TURN highlights that SCE's request is inappropriate in the current environment, where it would cause an extraordinarily high revenue requirement increase to be even higher.¹³²⁶

We do not find that SCE provides compelling justification for accelerating recovery of its wildfire insurance-related regulatory asset. The FERC Order cited by SCE does not require the expensing of the previously authorized insurance premiums. SCE acknowledges that the Commission is not mandated to follow the FERC guidance.¹³²⁷ The FERC Order addressed a compliance filing by SDG&E concerning SDG&E's wildfire costs. FERC found that SDG&E had improperly capitalized certain wildfire insurance premiums and other wildfire-related costs pursuant to FERC's accounting regulations.¹³²⁸ However, the FERC Order also provided that if these wildfire costs "are recoverable in future periods in CPUC-jurisdictional rates, SDG&E may defer the costs."¹³²⁹

¹³²³ *Ibid.*

¹³²⁴ *Ibid.*

¹³²⁵ Cal Advocates OB at 234; TURN OB at 192-193.

¹³²⁶ TURN OB at 192-193.

¹³²⁷ Ex. SCE-17, Vol. 2 at 36.

¹³²⁸ *Id.*, Appendix B at B-5.

¹³²⁹ *Id.* at B-7.

Therefore, the FERC order does not prohibit the continued capitalization of CPUC-jurisdictional amounts where authorized by the CPUC.

SCE does not identify a legal requirement that the previously authorized wildfire-related insurance premiums now be expensed. Moreover, SCE fails to demonstrate that any efficiencies or other benefits that may be gained from its proposal would justify a \$19 million increase to the TY revenue requirement, particularly given the many other rate increases (from this GRC and other proceedings and filings) facing ratepayers during this rate case cycle. Therefore, we decline to adopt any changes to the ratemaking treatment authorized for these costs in prior GRCs.

30. Employee Benefits and Programs

SCE's total compensation programs encompass base pay, short-term incentives, long-term incentives, recognition awards, and benefits. SCE forecasts TY O&M expenses of \$572.372 million for the following Employee Benefits and Programs:¹³³⁰

¹³³⁰ Ex. SCE-17, Vol. 3 at 10, Table III-5.

Employee Benefits and Programs	TY Forecast (\$000)
401K Savings Plan	95,229
Dental Plans	13,270
Disability Management - Administration	533
Disability Management - Programs	17,978
Executive Benefits	15,542
Executive Compensation	18,132
Group Life Insurance	1,366
Long-Term Incentives	11,602
Medical Programs	100,217
Miscellaneous Benefit Programs	6,302
Post-Retirement Benefits Other than Pensions (PBOP) Costs (Non-Service)	(9,834)
PBOP Costs (Service)	31,059
Pension Costs (Non-Service)	(18,821)
Pension Costs (Service)	103,170
Recognition	74
Severance	2,844
Short-Term Incentive Program (STIP)	180,906
Vision Service Plan	2,802
Total	572,372

Cal Advocates recommends adjustments to the forecasts for Executive Benefits, Long-Term Incentives, STIP, and the Recognition Program. TURN recommends adjustments to the forecasts for Executive Compensation, Executive Benefits, Long-Term Incentives, and STIP. The remainder of SCE's forecasts are unopposed.

We find reasonable and adopt the unopposed forecasts¹³³¹ subject to the following: (1) SCE shall make any necessary modifications to the forecasts to

¹³³¹ The unopposed forecasts are: the 401K Savings Plan, Dental Plans, Disability Management - Administration, Disability Management - Programs, Group Life Insurance, Medical Programs, Miscellaneous Benefit Programs, PBOP Costs (Non-Service), PBOP Costs (Service), Pension Costs (Non-Service), Pension Costs (Service), Severance, and the Vision Service Plan. SCE describes its forecast methodologies for these benefits and programs in Ex. SCE-06, Vol. 3, Pt. 1.

exclude all executive compensation costs (including base pay, bonuses, benefits) consistent with our determinations in the Executive Compensation section, below; and (2) SCE shall modify the forecasts, as necessary, based on the final adopted final labor forecast. Given the volatility in the forecasts for Pension costs, PBOP costs (excluding actuarial fees), Medical Programs, Dental Plans, and the Vision Plan, we approve SCE's unopposed requests to continue two-way balancing account treatment for these costs. The contested forecasts are discussed below.

30.1. Executive Compensation

30.1.1. Senate Bill 901 Compliance Requirement

The executive compensation we authorize in today's decision must comply with SB 901. SB 901, enacted in 2018 and effective January 1, 2019, revised Section 706 as follows:

706. (a) For purposes of this section, "compensation" means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation.

(b) An electrical corporation or gas corporation shall not recover expenses for compensation from ratepayers. Compensation shall be paid solely by shareholders of the electrical corporation or gas corporation.

The statute does not define who is an "officer" of an electrical or gas corporation.

Prior to SB 901, the authorized revenue requirement for electrical and gas corporations included ratepayer funding for officer compensation. In order to effectuate SB 901 and remove ratepayer funding of officer compensation without violating the statutory prohibition against retroactive ratemaking, the Commission in Resolution E-4963 directed electric and gas IOUs to establish

memorandum accounts to track officer compensation, as defined by Section 706, so that such amounts may be refunded to ratepayers through future proceedings. The Resolution made the finding that: “The term ‘officer’ means those employees of the investor owned utilities in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act.”¹³³²

Rule 240.3b-7, more commonly referred to as Rule 3b-7, states:

The term *executive officer*, when used with reference to a registrant, means its president, any vice president of the registrant in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy making function or any other person who performs similar policy making functions for the registrant. Executive officers of subsidiaries may be deemed executive officers of the registrant if they perform such policy making functions for the registrant.¹³³³

30.1.2. Party Positions

For TY 2021, SCE forecasts \$18.128 million for Executive Compensation expense, which includes base salaries, short-term incentives, associated expenses, and outside service expenses for executive officers.¹³³⁴ The forecast consists of labor expense of \$8.489 million and non-labor expense of \$9.639 million. In order to comply with SB 901, SCE removed the cost of seven named SCE officers from its forecast in accordance with the definition of “officer” adopted in

¹³³² Resolution E-4963 at 8, Finding 5.

¹³³³ 17 CFR 240.3b-7 (italics in original).

¹³³⁴ Ex. SCE-06, Vol. 3, Pt. 1 at 50; Ex. SCE-52A2E2, Appendix C at C9. This forecast reflects SCE’s AB 560 adjustment of \$4,812 to forecast labor expense presented in update testimony.

Resolution E-4963.¹³³⁵ In addition to SCE executives, SCE's forecast includes the costs for five executives who are dual officers of both SCE and Edison International (EIX) whose compensation costs are allocated between SCE and EIX.¹³³⁶ SCE's forecast also includes costs for certain EIX executives and their support staff whose roles directly benefit SCE.¹³³⁷

TURN recommends a TY forecast of \$4.803 million, a \$13.329 million reduction to SCE's forecast, based on removing most of the labor forecast (\$8.224 million) and the portion of non-labor expense that is composed of costs for shared officers and EIX executives that SCE allocates to ratepayers.¹³³⁸ If the Commission does not adopt this recommendation, TURN presents an alternative proposal to reduce SCE's Executive Incentive Compensation (EIC) program forecast by 50 percent because TURN argues that the EIC program's financial and lobbying goals primarily benefit shareholders.¹³³⁹

TURN's recommended TY forecast is based on removing compensation for all executives with titles of Vice President (VP) and above from SCE's forecast. TURN argues that SCE's interpretation of SB 901 is too narrow to comport with the intent of SB 901 and that VPs should be included in the definition of "officer"

¹³³⁵ The seven officers excluded from the forecast are: (1) Chief Executive Officer, (2) President, (3) Senior Vice President (SVP) & Chief Financial Officer, (4) SVP & General Counsel, (5) SVP Customer and Operational Services, (6) SVP Transmission and Distribution, and (7) SVP Regulatory Affairs. (SCE OB at 262-263.)

¹³³⁶ Ex. SCE-06, Vol. 3, Pt. 1 at 52-53.

¹³³⁷ *Id.* at 53-57.

¹³³⁸ TURN OB at 193, 196. TURN's recommended forecast does not incorporate SCE's AB 560 reduction. Incorporating the reduction would reduce TURN's forecast by \$4,812.

¹³³⁹ EIC is the short-term incentive pay program for executives. SCE includes executive officer EIC payments in labor costs for Executive Compensation and includes non-officer EIC costs in STIP. (Ex. SCE-06, Vol. 3, Pt. 1 at 47.)

since they are officers under SCE's corporate bylaws¹³⁴⁰ and SCE's organizational chart indicates they oversee large sections of SCE's business.¹³⁴¹ TURN contends that Resolution E-4963 did not necessarily define an officer as a Rule 3b-7 officer and that the Resolution could be interpreted as holding that the inclusion of all officers that are at the level of VP or above is consistent with Rule 3b-7.¹³⁴²

TURN also contends that the definition of "officer" adopted in Resolution E-4963 was for purposes of the memorandum accounts and to track interim costs and that the Commission did not necessarily intend for the definition to apply in all circumstances going forward.¹³⁴³ According to TURN, in the recent Sempra Utilities GRC, the Commission indicated the Commission's inclination to include all VPs in the definition of "officer."¹³⁴⁴

TURN also recommends that the Commission remove the entire SCE-allocated compensation forecast for shared officers and EIX executives. As to the shared officers, TURN notes that the portion of the shared officer costs that are allocated to SCE is based on the fact that such officers are employed by SCE, and therefore, is subject to SB 901. As to the EIX executives, TURN acknowledges that Resolution E-4963 declined to expand the definition of "officer" to include holding company executives. However, TURN asserts that additional facts that were not before the Commission when considering draft Resolution E-4963 support the exclusion of the costs associated with these positions. TURN argues that "without the presence of the Shared Officers and

¹³⁴⁰ Ex. TURN-04 at 33.

¹³⁴¹ TURN OB at 197-198.

¹³⁴² *Id.* at 200.

¹³⁴³ *Id.* at 198-199.

¹³⁴⁴ *Id.* at 203-204.

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.”¹³⁴⁵ TURN also argues that these costs would be excluded by Section 706 but for the artificial construct of the holding company.¹³⁴⁶

SCE responds that its proposals are consistent with Commission precedent and that TURN’s recommendations are inconsistent.¹³⁴⁷ SCE argues that TURN incorrectly interprets the findings of Resolution E-4963 and how Rule 3b-7 is applied. SCE also argues that TURN’s request that the Commission change the terms of Resolution E-4963 raises due process issues because the Resolution applies to ten separate utilities and cannot be changed without giving all of the utilities notice and a full opportunity to be heard.¹³⁴⁸ SCE raises a number of additional arguments as to why TURN’s arguments to expand the definition of “officer” are erroneous.¹³⁴⁹

30.1.3. Discussion

TURN suggests that Resolution E-4963 did not define an “officer” under SB 901 as a Rule 3b-7 officer but intended the definition to include all employees in positions with titles of VP and above. We confirm that Resolution E-4963 defined an “officer” for purposes of SB 901 as someone who is a Rule 3b-7 officer; otherwise, there would have been no need for the Resolution to reference Rule 3b-7. TURN’s request that the Commission “consider afresh” the definition

¹³⁴⁵ *Id.* at 206.

¹³⁴⁶ *Id.* at 207.

¹³⁴⁷ SCE OB at 262-263.

¹³⁴⁸ *Id.* at 267.

¹³⁴⁹ *Id.* at 265-269.

of officer appears to acknowledge that TURN's recommendation to exclude all positions of VP and above is not consistent with the definition adopted in Resolution E-4963.¹³⁵⁰

TURN's suggestion that the Commission indicated an intent to move away from the definition adopted in the Resolution in recent proceedings is also incorrect. In the Sempra Utilities 2019 GRC, the Commission directed SDG&E and SoCalGas to: "comply with Resolution E-4963 and track [officer compensation] costs through their respective [Officer Compensation Memorandum Accounts]."¹³⁵¹ The Commission directed compliance with Resolution E-4963, and nowhere did the Commission state that it was modifying the requirements set forth in Resolution E-4963. In PG&E's 2020 GRC, the question of whether the SB 901 exclusion should extend beyond the definition adopted in the Resolution was not addressed because PG&E voluntarily exceeded the requirements set forth in Resolution E-4963 and removed all officer compensation from its forecast.¹³⁵²

TURN raises a valid point that the definition adopted in Resolution E-4963 does not preclude future consideration of the definition. In Resolution E-4963, the Commission directed electric utilities to establish memorandum accounts so that rates authorized in pre-SB 901 rate cases could be refunded in future proceedings without violating the prohibition on retroactive ratemaking. The Commission in each utility's GRC evaluates whether the requested executive compensation costs are reasonable and should be recovered through rates. Contrary to SCE's arguments, there is no due process violation in examining this

¹³⁵⁰ TURN OB at 198.

¹³⁵¹ D.19-09-051 at 26.

¹³⁵² PG&E RB at 4.

issue in each utility's GRC. SCE has been afforded due process in this proceeding with respect to a possible change to the definition of "officer" for purposes of determining its recoverable executive compensation costs for this GRC period, and any definition we adopt in today's decision would apply only to SCE, not to any other IOU.

Having considered the parties' arguments, we find that TURN does not provide a compelling reason as to why all executives at the level of VP and above should be deemed an "officer" for purposes of Section 706. TURN suggests that its proposed outcome is in the spirit of SB 901. However, TURN does not explain what the legislative intent of SB 901 is or explain why a more expansive definition of "officer" would effectuate the Legislature's intent. SB 901 does not define "officer" or set forth any statement of the Legislature's intent with respect to amended Section 706.

The Legislature's use of the term "officer" rather than "executive officer" could be construed as supporting a more expansive interpretation. As TURN notes, the Rule 3b-7 definition is for an "executive officer" not an "officer."¹³⁵³ However, there is often not a clear distinction drawn between the terms "executive officer" and "officer." The Commission has noted that the terms "'[e]xecutive compensation' and 'officer compensation' are frequently used interchangeably in GRC testimony and decisions."¹³⁵⁴ SCE also notes that the

¹³⁵³ The Public Utilities Code does define the term "executive officer," which is similar to the definition provided in Rule 3b-7. Section 451.5(c) states: "For purposes of this section, 'executive officer' means any person who performs policy making functions and is employed by the public utility subject to the approval of the board of directors, and includes the president, secretary, treasurer, and any vice president in charge of a principal business unit, division, or function of the public utility."

¹³⁵⁴ Resolution E-4963 at 3, fn. 4.

SEC uses essentially the same definition for “officer” under Rule 16a-1(f)¹³⁵⁵ and “executive officer” under Rule 3b-7. SCE states that the only practical difference between the “officers” and “executive officers” SCE designates pursuant to the SEC’s rules is that SCE’s Controller is considered an “officer” but not an “executive officer.”¹³⁵⁶

We do not find that TURN provides a reasoned basis for its proposed definition. TURN acknowledges that many of the VPs lead units that are below the overarching units overseen by SVPs but argues that VPs are still in charge of large portions of SCE’s business, perhaps what Rule 3b-7 may designate as a “division.”¹³⁵⁷ TURN’s position is contradictory in that TURN asserts that the Commission should not rely on the Rule 3b-7 definition but at the same time appears to argue that VPs should be considered an officer under Section 706 because they might qualify as an officer under Rule 3b-7.

We do not find TURN’s analysis to be persuasive. A VP in charge of a “division” is not defined as an executive officer under Rule 3b-7. Rather, only VPs that are in charge of a “principal business unit, division or function” or who perform a policy making function are executive officers under Rule 3b-7. The adjective “principal” is a modifier for all of the nouns that follow in the list. By

¹³⁵⁵ Rule 16a-1-f of the Securities Exchange Act provides, in part:

The term “officer” shall mean an issuer's president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer.

(17 CFR 240.16a-1(f).)

¹³⁵⁶ SCE OB at 265.

¹³⁵⁷ TURN OB at 197-198.

setting forth conditions under which a VP will be considered a Rule 3b-7 officer, it is clear that the Rule did not intend for all VPs to be considered Rule 3b-7 officers. Moreover, there is no evidence to suggest that SCE has failed to accurately report its Rule 3b-7 officers to the SEC.

We find there is a reasonable basis for drawing a distinction between treatment of compensation for Rule 3b-7 officers and other executives and employees. Rule 3b-7 officers are senior-level management, responsible for policy decisions of the company, and directly answerable to SCE's Board of Directors because their hiring and firing are determined by the Board.¹³⁵⁸ As noted by TURN, executives whose employment is dependent on annual vote of the Board of Directors are different from other employees and may be more incentivized to make decisions based on stock and financial performance.¹³⁵⁹ In the absence of a clear definition of "officer" in the statute, a clear statement of legislative intent with respect to the statute, or a reasoned basis for an alternative definition presented in this proceeding, we find it reasonable to continue to apply the definition of "officer" adopted in Resolution E-4963.

With respect to the issue of shared officers, these employees are also employees of SCE for part of the year. Of the five shared officers, SCE allocates 99 percent of the position to SCE for four shared officers and 70 percent of the position to SCE for one shared officer.¹³⁶⁰ Consistent with our treatment of full-time SCE officers, we exclude all compensation, as defined by Section 706, for shared officers who are Rule 3b-7 officers of SCE from rates. According to

¹³⁵⁸ SCE OB at 267-268.

¹³⁵⁹ Ex. TURN-04 at 33-34.

¹³⁶⁰ *Id.* at 39, Figure 4.

SCE's 2019 Annual Report, one of the shared officers included in SCE's request, the SVP of Human Resources, is a Rule 3b-7 officer.¹³⁶¹

TURN also recommends that compensation for EIX executives that is allocated to SCE should also be excluded from rates. SCE argues that it is clear that SB 901 does not apply to EIX executives since it only applies to "an officer of an electric corporation."¹³⁶² SCE correctly notes that EIX is not an electric corporation and that SB 901 does not apply to EIX. In Resolution E-4963, we rejected the recommendations of SCE and the Utility Consumers' Action Network to include EIX executives in the definition of "officer" for purposes of SB 901.¹³⁶³ Since SB 901 does not require these costs to be excluded from rates, we decline to adopt TURN's recommendation.

SCE is directed to submit a Tier 1 advice letter updating its Officer Compensation Memorandum Account consistent with the directives of this decision.

30.2. Executive Benefits

SCE's Executive Benefits forecast includes costs for the Executive Retirement Plan.¹³⁶⁴ The Executive Retirement Plan is a non-qualified pension plan that provides benefits that executives cannot receive in the qualified SCE Retirement Plan due to compensation and payout limits imposed by the Internal Revenue Code on that plan. SCE forecasts \$15.542 million of TY expenses for

¹³⁶¹ Ex. SCE-06, Vol. 3, Pt. 1 at 52-53; Ex. SCE-42 at p. 138.

¹³⁶² SCE OB at 269.

¹³⁶³ Resolution E-4963 at 6.

¹³⁶⁴ Ex. SCE-06, Vol. 3, Pt. 1 at 134.

Executive Benefits.¹³⁶⁵ To develop its forecast, SCE multiplies the average executive benefit cost per employee in 2018 by the projected number of employees in 2021 with no escalation factor applied. SCE's forecast excludes the cost of the seven named SCE officers listed above to comply with SB 901.

Based on the same arguments TURN makes with respect to Executive Compensation, TURN recommends that the Commission disallow Executive Benefits for employees in positions of Vice President or above. TURN's recommendation would reduce SCE's forecast by \$2.376 million resulting in a forecast of \$13.166 million.¹³⁶⁶

Cal Advocates argues that the Commission has consistently ordered ratepayers and shareholders to equally share Executive Benefits expense, and therefore, recommends ratepayer funding of no more than 50 percent of SCE's forecast.¹³⁶⁷

For the reasons discussed above in the Executive Compensation section, SCE is directed to exclude all costs for SCE executives and shared officers who are Rule 3b-7 officers of SCE from the Executive Benefits forecast. Furthermore, since SCE's 2009 GRC, the Commission has consistently allowed rate recovery of 50 percent of SCE's Executive Benefits forecast.¹³⁶⁸ The Commission adopted this approach in past GRCs because Executive Benefits are based, in part, on

¹³⁶⁵ *Id.* at 136. The parties' forecasts presented in the joint comparison exhibit differ slightly from the forecasts presented in their testimony due to changes in labor. (Ex. SCE-54 at 216.) The final Executive Benefits forecast will depend on the adopted labor forecast.

¹³⁶⁶ TURN OB at 195. TURN's initial recommendation was to disallow all funding for Executive Benefits. However, TURN modified its recommendation based on information from SCE that not all of the costs forecast were for Vice Presidents and above.

¹³⁶⁷ Ex. PAO-11 at 21 citing D.14-08-032, D.15-11-021, and D.19-05-020.

¹³⁶⁸ D.19-05-020 at 193; D.15-11-021 at 275; D.12-11-051 at 477; D.09-03-025 at 146.

executive bonuses, not all of which are recoverable in rates.¹³⁶⁹ The Commission has also found that these costs should be equally shared between ratepayers and shareholders because both receive benefits from the retention of executives and managers.¹³⁷⁰ These rationale continue to apply in this case. Therefore, consistent with past Commission precedent, we approve 50% of the remainder of the Executives Benefits forecast (after deducting the costs for the Rule 3b-7 officers) for inclusion in rates.

30.3. Long-Term Incentives

SCE offers Long-Term Incentive compensation (LTI) to executives in the form of stock options, restricted stock units, and performance shares. SCE forecasts TY expenses of \$11.602 million for LTI.¹³⁷¹ SCE acknowledges that the Commission has not viewed SCE's past requests for rate recovery of its LTI program favorably and has admonished SCE for continuing to do so.¹³⁷² However, SCE argues that LTI should be recoverable as a cost of service because it is an integral part of the total compensation package for executives and is essential to SCE's efforts to attract and retain high-performing leaders. SCE notes that nearly every IOU and comparable business enterprise includes LTI in the total compensation package for executives.¹³⁷³ SCE also notes that AB 1054 recognizes the importance of long-term incentives by directing electrical corporations to establish a compensation structure for executives based on a

¹³⁶⁹ D.19-05-020 at 193.

¹³⁷⁰ D.14-08-032 at 533-535.

¹³⁷¹ Ex. SCE-06, Vol. 3, Pt. 1 at 61.

¹³⁷² *Id.* at 62.

¹³⁷³ *Ibid.*

“long-term structure that provides a significant portion of compensation, which may take the form of grants of the electrical corporation’s stock.”¹³⁷⁴

Cal Advocates and TURN argue that the Commission should deny SCE’s request to have ratepayers fund any portion of the LTI program. Both parties argue that LTI is intended to reward SCE employees for promoting the company’s financial performance and shareholder interests rather than ratepayer interests. Both parties also argue that SCE does not raise any arguments that would warrant a departure from the Commission’s longstanding policy of excluding these costs from rates.¹³⁷⁵

Going back to at least the 2009 GRC, the Commission has excluded SCE’s LTI costs from rates because LTI does not align executives’ interests with ratepayer interests.¹³⁷⁶ SCE does not present any new arguments that would warrant a departure from this longstanding policy. We continue to find that LTI is primarily designed to reward SCE employees for promoting shareholder interests. SCE explains that “LTI awards and payouts depend on multiple years of continuous employment, strong executive performance, and thriving SCE financial health.”¹³⁷⁷ Moreover, LTI is closely tied to the stock performance of EIX since LTI awards take the form of equity in EIX.¹³⁷⁸

SCE’s arguments that reconsideration of this issue is merited in light of AB 1054 are not convincing. Although AB 1054 requires electrical corporations to establish a compensation structure which provides a significant portion of

¹³⁷⁴ Ex. SCE-06, Vol. 3, Pt. 1 at 62 quoting Pub. Util. Code § 8389(e)(6)(A)(iii).

¹³⁷⁵ Cal Advocates OB at 235-237; TURN OB at 209-211.

¹³⁷⁶ D.19-05-020 at 188; D.15-11-021 at 266; D.12-11-051 at 451-452; D.09-03-025 at 134-135.

¹³⁷⁷ Ex. SCE-06, Vol. 3, Pt. 1 at 65.

¹³⁷⁸ *Id.* at 66.

executive officer compensation based on performance, we agree with Cal Advocates that nowhere does AB 1054 indicate that ratepayers should fund LTI.¹³⁷⁹ In fact, AB 1054 did not amend the provision in Section 706, which prohibits compensation for officers, which would include LTI, from being recovered from ratepayers.

Based on the foregoing, we see no reason to discontinue our longstanding policy of denying ratepayer recovery for LTI. Therefore, SCE's request to include these costs in rates is denied.

30.4. Short-Term Incentive Program

SCE's annual Short-Term Incentive Program (STIP) is an annual variable pay program that gives employees an opportunity to earn a cash award based on achieving Company goals. SCE's STIP includes the following plans: (1) the Short-Term Incentive Plan for non-executives, (2) the Key Contributor Incentive Plan (KCIP) for limited non-executives, and (3) the Executive Incentive Compensation Plan (EIC) for those executives who are not officers (less than one percent of the employee population).¹³⁸⁰

30.4.1. Party Positions

SCE argues that variable pay represents an important element of an overall total compensation package and is a legitimate business expense that should be recovered in cost-of-service based rates.¹³⁸¹ According to SCE, the Total Compensation Study (TCS) shows that STIP is part of an employee's at-market compensation package.¹³⁸² SCE argues that variable pay benefits customers by

¹³⁷⁹ Cal Advocates OB at 236.

¹³⁸⁰ Ex. SCE-06, Vol. 3, Pt. 1 at 40-41.

¹³⁸¹ *Id.* at 44-45.

¹³⁸² SCE OB at 260.

adding to reasonable employee compensation in a fashion that avoids the increased costs in pension and benefit costs associated with base pay.¹³⁸³

SCE also argues that the Company goals for the program are tied to matters benefiting customers.¹³⁸⁴ The STIP goals change from year to year, as do the weightings of each metric. SCE's STIP and EIC goals for 2019 are: Financial Performance, as measured by Core Earnings (weighted at 30 percent); Wildfire Resiliency (weighted at 20 percent); Operational and Service Excellence (weighted at 25 percent); Policy, Growth and Innovation (weighted at 15 percent); and Diversity, People and Culture (weighted at 10 percent).¹³⁸⁵ SCE contends that financially-based metrics do not only benefit shareholders because ratepayers bear additional costs when a company is not financially healthy, such as increased costs of debt financing for SCE's operations and capital projects.¹³⁸⁶ SCE also contends that its regulatory goals are based on advocating for its customers and complying with established State policies.¹³⁸⁷

SCE's TY forecast for the total of its STIP programs is \$180.907 million.¹³⁸⁸ SCE's forecast is based on an itemized forecast methodology, which incorporates

¹³⁸³ Ex. SCE-06, Vol. 3, Pt. 1 at 45-46.

¹³⁸⁴ *Id.* at 45.

¹³⁸⁵ *Id.* at 43, Table III-7.

¹³⁸⁶ SCE OB at 270-271.

¹³⁸⁷ *Id.* at 272-274.

¹³⁸⁸ Ex. SCE-06, Vol. 3, Pt. 1 at 41. SCE subsequently updated its STIP forecast to \$178.296 million based on its updated labor forecast presented in its Update Testimony. (Ex. SCE-54 at 218.) Cal Advocates and TURN both address SCE's forecast as initially presented in SCE's direct testimony and their recommendations are based on SCE's initial forecast. For ease in comparing and understanding the parties' positions, we discuss SCE's forecast as initially presented. The final STIP forecast will ultimately depend on the final adopted labor forecast.

SCE's labor forecast.¹³⁸⁹ SCE determines a program expense ratio by dividing 2018 plan costs by 2018 recorded non-capital labor expense. SCE then applies this expense ratio to the projected non-capital labor forecast for 2019-2021. SCE also makes further adjustments to reflect anticipated incremental costs arising from job classification changes tied to the Compensation Design Project.

Cal Advocates recommends STIP funding of \$63.317 million based on: (1) removing ratepayer funding for incentives for the Financial Performance goal because the goal provides no benefit to ratepayers, and (2) sharing the remaining STIP costs between ratepayers and shareholders.¹³⁹⁰ Cal Advocates notes that SCE weighted financial goals at 40 percent in the 2018 GRC but weights these goals at 30 percent in the current GRC. Cal Advocates argues that SCE's attempt to adjust the metrics by reducing the weight of the one goal the Commission has consistently disallowed is a transparent attempt to increase ratepayer funding for the program. Cal Advocates argues that shareholders also benefit from STIP and should contribute a more significant portion to the program, regardless of the metrics. Therefore, Cal Advocates recommends that ratepayers fund no more than half of the STIP program costs after the removal of the costs for the Financial Performance goal metric.¹³⁹¹

TURN recommends STIP funding of \$51.759 million based on two primary recommendations: (1) reducing STIP funding to 12.11 percent of labor expense (\$77.388 million reduction), and (2) removing funding for incentives related to

¹³⁸⁹ SCE describes its forecast methodology in Ex. SCE-06, Vol. 3, Pt. 1 at 46-47.

¹³⁹⁰ Cal Advocates OB at 238-239.

¹³⁹¹ *Id.* at 239.

goals that primarily benefit shareholders rather than ratepayers (\$51.760 million reduction).¹³⁹²

TURN believes that increases in STIP levels should not exceed increases in SCE's labor costs. TURN notes that SCE's requested STIP funding would total 21.2 percent of labor, which is 70 percent above the 12.11 percent ratio adopted in SCE's previous two GRC decisions.¹³⁹³ TURN also notes that the impacts of the STIP increases would be uneven among employee groups and be mainly attributed to higher salary levels.¹³⁹⁴ TURN argues that SCE fails to demonstrate that such increases would be necessary to compete in the labor market and that the TCS shows that the company's compensation is already at market.

TURN also argues that ratepayers should not pay for the following metrics and goals that primarily benefit shareholders: (1) the Financial Performance goal of "Maintain Core Earnings;" (2) goals to shape legislation and regulatory policy within the Policy, Growth, and Innovation Goal Category; and (3) policy goals within the Wildfire Resiliency goal category.¹³⁹⁵ TURN recommends that the Commission also consider a formal policy of sharing STIP costs between shareholders and ratepayers for measures that benefit them both.¹³⁹⁶

In addition, TURN recommends that the Commission deny ratepayer funding for costs related to the KCIP program. According to SCE, KCIP awards are not based on the STIP goals but are awarded based on manager discretion

¹³⁹² TURN OB at 224, Table 28-2.

¹³⁹³ *Id.* at 212.

¹³⁹⁴ *Ibid.*

¹³⁹⁵ *Id.* at 216-222.

¹³⁹⁶ *Id.* at 225.

with no specific metrics set for the awards.¹³⁹⁷ TURN argues that there is no evidence that KCIP spending is necessary for employee retention or that the program encourages behavior that benefits ratepayers.

30.4.2. Discussion

SCE argues that variable pay is an important element of an overall total compensation package and should be recovered in cost-of-service based rates if the total compensation package is at market. The Commission has previously found that “offering employee compensation in the form of incentive payments is useful for recruiting and retaining skilled professionals and improving work performance” and “is a generally accepted compensation practice.”¹³⁹⁸ However, the Commission has repeatedly rejected arguments that cost-of-service ratemaking principles require ratepayers to fully fund incentive compensation where elements of the program essentially benefit shareholders without a clear demonstrable benefit to ratepayers, including in cases where the utility has argued that the total compensation package was at market.¹³⁹⁹ The Commission has explained that “the sharing of cost responsibility promotes a reasonable matching of costs with benefits experienced both by ratepayers and shareholders.”¹⁴⁰⁰ The Commission has also noted that it is within SCE management’s discretion to target incentive compensation to achieve ratepayer benefits.¹⁴⁰¹

¹³⁹⁷ RT, Vol. 8 at 916.

¹³⁹⁸ D.14-08-032 at 520.

¹³⁹⁹ D.19-05-020 at 186; D.15-11-021 at 255-257, 264-265; D.14-08-032 at 521, 522; D.12-11-051 at 458.

¹⁴⁰⁰ D.14-08-032 at 522.

¹⁴⁰¹ D.15-11-021 at 257.

In SCE's 2015 and 2018 GRCs, the Commission determined STIP funding levels by first applying the historical ratio of STIP to total labor expense, and then excluding costs associated with goals that primarily benefit shareholders. We find it reasonable to continue to use this methodology to determine the level of ratepayer funding for the STIP program. In addition, we find it reasonable to exclude ratepayer funding for the KCIP program, and therefore, exclude recorded costs for KCIP and its predecessor, the Augment Plan, when calculating the historical STIP to labor ratio.

The Commission has previously expressed concerns about the rapid growth in discretionary STI costs, which were rising much faster than the employee population, and the fact that STI funds were distributed in a way that favors executives and managers.¹⁴⁰² We continue to have these concerns. SCE's STIP request in this GRC would total 21.2 percent of labor expense, 70 percent above the 12.11 percent adopted in the 2015 and 2018 GRCs.¹⁴⁰³ We do not find that SCE has justified an increase beyond historical levels. Consistent with the 2015 and 2018 GRCs, we find it reasonable to limit ratepayer funding of STIP based on the historical ratio of STIP to total labor expenses.

TURN proposes a historical ratio of 12.11 percent based on the ratio adopted in the 2015 and 2018 GRCs. The 12.11 percent ratio is based on the six-year average for 2008-2013.¹⁴⁰⁴ SCE is opposed to the application of a historical STIP to labor ratio but argues that if the Commission decides to adopt a

¹⁴⁰² D.12-11-051 at 457.

¹⁴⁰³ TURN OB at 212.

¹⁴⁰⁴ Ex. SCE-17, Vol. 3 at 31, Table III-11.

ratio, the ratio should be updated to 18.18 percent based on a more current six-year (2014-2019) average.¹⁴⁰⁵

We agree with SCE that the 12.11 percent initially adopted in 2015 is based on outdated data. Given the findings in the TCS that SCE's total compensation, which includes STIP, is at market,¹⁴⁰⁶ we find it appropriate to update the ratio based on more recent data. However, rather than the six-year average proposed by SCE, we find it reasonable to adopt a ratio of 16.10 percent based on a five-year (2014-2018) average, which excludes costs for the KCIP plan and the Augment Plan.¹⁴⁰⁷

We find it reasonable to exclude the 2019 data when calculating the average because SCE indicates it is based on preliminary unadjusted data.¹⁴⁰⁸ Furthermore, the TCS is based on 2018 recorded costs and does not provide any analysis as to whether the 2019 costs are at market.¹⁴⁰⁹

We also find it reasonable to exclude the recorded costs for KCIP and the Augment Plan when calculating the average because we find that SCE has failed to demonstrate the reasonableness of ratepayer funding for its KCIP program. As discussed above, the Commission has generally found that ratepayer recovery of incentive compensation program costs is reasonable where there is a demonstration of ratepayer benefits. SCE explains that KCIP payouts are based

¹⁴⁰⁵ *Id.* at 32, Table III-12.

¹⁴⁰⁶ Ex. SCE-06, Vol. 3, Pt. 1 at 44; Ex. SCE-06, Vol. 3, Pt. 2 at 4 (The TCS estimates that SCE total compensation levels are below market by 3.0 percent with a degree of accuracy of plus or minus 5 percent).

¹⁴⁰⁷ Ex. SCE-17, Vol. 3 at 32, Table III-12 and Appendix A at A-85.

¹⁴⁰⁸ *Id.* at 32, Table III-12.

¹⁴⁰⁹ Ex. SCE-6, Vol. 3, Pt. 2 at 4, fns. 1-3; Ex. SCE-17, Vol. 3 at 27.

on manager discretion and not based on any specific metrics.¹⁴¹⁰ Based on the information provided by SCE, we are unable to determine whether the program aligns with ratepayer interests, and therefore, do not find it reasonable for ratepayers to fund the costs related to the program.

In addition, we find it reasonable to continue to exclude costs associated with the STIP/EIC goals that primarily benefit shareholders. Our review of the STIP/EIC goals is based on SCE's 2019 goals, which SCE presented in its direct testimony in support of its funding request and which intervenors had the opportunity to analyze and address in their testimony. SCE notes that it subsequently revised its goals for 2020.¹⁴¹¹ Because management has the discretion to change the goals and weightings each year, it is unclear that the 2020 goals would necessarily be more representative of the goals for 2021-2023. Moreover, since SCE presented these revised goals in rebuttal testimony, other parties did not have the opportunity to present testimony on the revised goals and there is a lack of detail in the record regarding the 2020 goals compared to the 2019 goals.

SCE has the burden of demonstrating that the costs related to the program criteria are reasonable.¹⁴¹² We find that SCE has failed to demonstrate that costs related to the Financial Performance goal category are reasonable, and therefore, adopt Cal Advocates' and TURN's recommendations to exclude ratepayer funding for this goal (30 percent weight). Ratepayers can receive certain benefits from a financially healthy company. However, as in past GRCs, we continue to

¹⁴¹⁰ RT, Vol. 8 at 916.

¹⁴¹¹ SCE Proposed Decision (PD) Opening Comments at 11.

¹⁴¹² D.15-11-021 at 264-265.

find that this goal is primarily intended to benefit shareholders.¹⁴¹³ The goal may or may not result in secondary benefits to ratepayers since a goal of “achieving core earnings” does not always align shareholder and ratepayer interests. For example, the Commission has found that incentives to increase earnings do not always align with incentives to address safety or reliability issues.¹⁴¹⁴

We also adopt TURN’s recommendation to exclude ratepayer funding for costs associated with policy shaping goals. TURN estimates that approximately 20 percent of the STIP goals are related to policy shaping goals.¹⁴¹⁵

- The Policy, Growth and Innovation goal category (15 percent weight) includes the following goal: “Shape California legislative and regulatory policies to align with SCE’s strategy.” In 2019, the policy shaping goal constituted approximately 63 percent of the goal category, or over 9 percent of the total STIP target.
- The Wildfire Resiliency goal category (20 percent weight) includes the goal of “Policy Reform, Wildfire.” In 2019, the policy reform goal constituted approximately 53 percent of the goal category, or approximately 11 percent of the total STIP target.

We find unpersuasive SCE’s arguments that its policy and regulatory goals are primarily intended to benefit customers.¹⁴¹⁶ As previously explained by the Commission, payout criteria that are based on “achieving decisions in CPUC proceedings (GRC, cost of capital) with certain outcomes and achieving specified policy objectives” are “directly related to shareholder benefits” and “may or may

¹⁴¹³ See D.19-05-020 at 186; D.14-08-032 at 521.

¹⁴¹⁴ D.14-08-032 at 521.

¹⁴¹⁵ Ex. TURN-05 at 17-18; Ex. TURN-05-Atch.1 at 87.

¹⁴¹⁶ SCE OB at 272-274.

not provide secondary benefits to ratepayers.”¹⁴¹⁷ In fact, some of these policy efforts, such as efforts to “improve cost recovery certainty and reasonable allocation of liability,”¹⁴¹⁸ may be directly at odds with ratepayer interests.

TURN and Cal Advocates also recommend that shareholders and ratepayers equally share costs for the remainder of the STIP goals. As discussed above, we limit STIP funding based on historical STIP to labor ratios and exclude ratepayer funding for 50 percent of the STIP program goals, which we find primarily benefit shareholders. We find that this results in an equitable sharing of STIP program costs between shareholders and ratepayers and do not find additional reductions to be justified. Shareholders may receive some benefits from the STIP goals that primarily benefit ratepayers and are fully ratepayer funded. By the same token, ratepayers may receive some benefits from the STIP goals that primarily benefit shareholders and are fully shareholder funded.

Therefore, we approve ratepayer funding for STIP based on the following methodology: (1) we apply a 16.10 percent ratio to SCE’s adopted labor forecast; and (2) we reduce the resulting forecast by 50 percent to remove costs associated with financial and policy shaping goals.¹⁴¹⁹ The final STIP forecast will depend on the adopted labor forecast and be calculated in the Results of Operations model.

¹⁴¹⁷ D.15-11-021 at 264.

¹⁴¹⁸ TURN OB at 220 citing TURN DR 10-05a; Ex. TURN-05-Atch.1 at 61.

¹⁴¹⁹ Because EIC and STIP share the same goals and weights, any EIC costs included in the executive compensation forecast that are not otherwise disallowed based on the discussion in Section 30.1.3, above, should also be reduced by 50 percent.

30.5. Recognition

According to SCE, its recognition programs are “low-cost tools that reward individual and team achievements.”¹⁴²⁰ The program includes cash awards, called Spot Awards, and non-cash awards in the form of points redeemable for merchandise through the Encore program. Spot Awards recognize an individual or team for delivering exceptional, measurable results such as making significant contributions to public or employee safety, significantly improving efficiency across one or more Operating Units (OUs), and leading a Company-wide team or major project that notably exceeds expectations within scheduled time frames and under budget.¹⁴²¹ Encore Awards recognize workers for their achievements to help transform the company’s safety culture.¹⁴²²

SCE forecasts TY expenses of \$2.096 million for its recognition programs.¹⁴²³ SCE’s TY forecast is based on each OU having a budget of 0.15 percent of its individual labor budget to spend on employee recognition. The forecast costs are included within the OU in which the 2018 awards were recorded. SCE also forecasts TY expenses of \$0.074 million for SCE’s vendor to administer the recognition programs.¹⁴²⁴

Cal Advocates recommends a 50 percent disallowance of SCE’s TY forecast of \$0.074 million for program administration costs.¹⁴²⁵ Cal Advocates argues that ratepayers and shareholders should equally share the expense for the program

¹⁴²⁰ Ex. SCE-06, Vol. 3, Pt. 1E2 at 68.

¹⁴²¹ *Id.* at 69.

¹⁴²² *Ibid.*

¹⁴²³ *Id.* at 68.

¹⁴²⁴ Ex. SCE-17, Vol. 3 at 59, Table III-18.

¹⁴²⁵ Cal Advocates OB at 245.

due to at least one job category being over market and SCE's significant overspending on this program in recent years.¹⁴²⁶

As in the 2015 and 2018 GRCs, we continue to find that "the types of behaviors (e.g., a focus on safety) that [SCE's recognition] programs reward further the provision of safe and reliable service at just and reasonable rates, and that the program costs appear reasonable relative to the benefits."¹⁴²⁷ We find reasonable and approve SCE's forecasts for this program. SCE presents evidence that companies commonly use recognition programs and that SCE's budget is in line with those used by the majority of organizations for such programs.¹⁴²⁸

Although Cal Advocates raises concerns regarding historical overspending for the program, SCE's forecast is not based on SCE's prior recorded costs.

Moreover, given that SCE's budget for these programs is 0.15 percent of labor, we do not find that inclusion of these program costs would have a material impact on SCE's total compensation levels, which the TCS estimates are below market by 3.0 percent with a degree of accuracy of plus or minus 5 percent.¹⁴²⁹

31. Employee Training and Support

The Employee Training BPE is composed of the company's enterprise-wide training and development programs, which are intended to ensure that employees are equipped with the knowledge and skills to do their jobs

¹⁴²⁶ *Ibid.*

¹⁴²⁷ D.19-05-020 at 188 citing D.15-11-021.

¹⁴²⁸ Ex. SCE-06, Vol. 3, Pt. 1 at 70.

¹⁴²⁹ Ex. SCE-06, Vol. 3, Pt. 2 at 4. Recognition programs are excluded from the TCS study. (Ex. SCE-17, Vol. 3 at 61.)

effectively and safely. SCE forecasts Employee Training TY expenses of \$63.475 million for the following activities:¹⁴³⁰

Activity	TY Forecast (\$000)
Employee Training and Development	19,103
Training Delivery and Development for T&D	17,908
Training Seat-Time for T&D	26,463
Total	63,475

Cal Advocates has reviewed SCE's historical expenses and TY forecasts for these activities and does not oppose SCE's forecasts.¹⁴³¹ SCE's forecasts are generally consistent with historical expenses (either last year recorded or multi-year average) with incremental expenses forecast for T&D training for new initiatives related to wildfire mitigation and Grid Modernization.¹⁴³² We find reasonable and adopt SCE's unopposed Employee Training forecasts.

The Employee Support BPE is composed of OU Support Services and Talent Solutions work activities. The responsibilities of OU Support Services include supporting the OUs as a whole, such as Business Partner Support and Organizational Development/Organizational Effectiveness Support, and other employee specific activities, such as, Employee Relations, Labor Relations, Internal Communications, and Administrative Support.¹⁴³³ The Talent Solutions department provides governance, consultation, guidance, and assistance with attracting, assessing, and managing organizational talent.¹⁴³⁴

¹⁴³⁰ Ex. SCE-06, Vol. 3, Pt. 1 at 152, Table IV-20; Ex. SCE-06, Vol. 3 Pt. 1E at 138, 142-143.

¹⁴³¹ Ex. PAO-11 at 22-27.

¹⁴³² Ex. SCE-06, Vol. 3, Pt. 1 at 151, 153-155, 159-162.

¹⁴³³ *Id.* at 9-12.

¹⁴³⁴ *Id.* at 16.

SCE's TY forecast for Employee Support is \$40.347 million, consisting of \$29.212 million for OU Support Services and \$11.135 million for Talent Solutions.¹⁴³⁵ SCE's forecasts are based on last year recorded (2018) costs with adjustments.¹⁴³⁶ SCE's OU Support Services forecast incorporates the following reductions recommended by TURN: (1) a \$1.289 million reduction to the labor forecast based on removing the 2.9 percent labor escalation rate SCE initially applied to the 2018 base year forecast, and (2) a \$2.204 million reduction to the non-labor forecast because costs anticipated for union-negotiated benefit changes did not materialize.¹⁴³⁷

SCE's forecasts for Employee Support, as modified based on TURN's recommendations, are uncontested. Cal Advocates also reviewed SCE's historical expenses and initial TY forecasts for these activities and does not oppose SCE's forecasts.¹⁴³⁸ We find reasonable and approve SCE's uncontested total Employee Support TY forecast of \$40.347 million.

32. Environmental Services

SCE's Environmental Services Department (ESD) develops and manages environmental programs to support SCE's compliance with laws and regulations established by state and local governments.

32.1. Environmental Services O&M

SCE forecasts total TY O&M expenses of \$27.683 million for Environmental Services.¹⁴³⁹ SCE's forecast includes: (1) \$9.745 million for Environmental

¹⁴³⁵ Ex. SCE-17, Vol. 3 at 6, Table II-3; Ex. SCE-52A2E2, Appendix C at C9. The OU Support Services forecast reflects SCE's AB 560 adjustments made in update testimony.

¹⁴³⁶ Ex. SCE-06, Vol. 3, Pt. 1 at 15-16, 23.

¹⁴³⁷ Ex. SCE-17, Vol. 3 at 7-8.

¹⁴³⁸ Ex. PAO-11 at 3-6.

¹⁴³⁹ Ex. SCE-06, Vol. 4 at 5.

Management and Development, which involve the administrative and general activities for ESD to support and maintain SCE's environmental responsibilities, and (2) \$17.937 million for Environmental Programs, which involve activities performed by ESD to comply with environmental requirements such as storm water management, air quality permitting, environmental clearance, hazardous waste management, spill prevention control and countermeasures, hazardous materials management, and marine mitigation programs.¹⁴⁴⁰ SCE's forecast is based on last year recorded (2018) costs less adjustments based on anticipated departmental efficiencies and other cost savings.¹⁴⁴¹ We find reasonable and approve SCE's uncontested TY O&M forecast.

32.2. Environmental Services Capital

SCE requests that the Commission authorize the following 2019 recorded and 2020-2021 forecast capital expenditures (nominal, \$000) for Environmental Services:¹⁴⁴²

Capital Expenditures	2019	2020	2021
Well Decommissioning	680	530	541
Avian Retrofits	-	-	1,250
Programmatic Permits	-	-	1,140
Total	680	530	2,931

SCE's capital expenditure forecast is uncontested. We find reasonable and approve SCE's uncontested 2019-2021 capital expenditures for Well

¹⁴⁴⁰ *Id.* at 12-14, 17-21. The marine mitigation costs reflect SCE's share (78.21 percent) of the project's costs. (*Id.* at 23.)

¹⁴⁴¹ *Id.* at 16-17, 23-25.

¹⁴⁴² *Id.* at 25, Table II-3; Ex. SCE-17, Vol. 4 at 4. SCE's rebuttal testimony appears to miscalculate the 2019 recorded expenditures as \$1.460 million. (*See* Ex. SCE-17, Vol. 4 at 4.) SCE indicates that its recorded 2019 expenditures exceeded its 2019 forecast of \$560,000 by \$120,000, which would result in 2019 recorded expenditures of \$680,000.

Decommissioning and Programmatic Permits.¹⁴⁴³ However, we find that SCE has failed to provide adequate justification for its new proposed Avian Retrofits program. SCE states that the new program will fund work necessary to upgrade deficient poles to SCE's avian safe construction standards, including proactive and reactive retrofits, which will reduce impacts to birds, improve reliability, and help with fire prevention.¹⁴⁴⁴ Given the significant capital expenditures we approve in this decision for pole maintenance, repair, and replacement via programs such as the Pole Loading Program, Deteriorated Pole Program, and Aerial Inspection Maintenance Program, SCE fails to adequately justify the need for this additional funding for pole retrofits to ensure safety and reliability. Therefore, we deny SCE's requested funding for this new program.

33. Audit Services

SCE's Audit Services Department (Audits) helps ensure that business risks are appropriately identified, compliance with regulatory requirements occurs, and senior management and the board of directors receive information and advice about mitigating risks to enable effective management response.

SCE forecasts TY O&M expenses of \$9.710 million for Audits, consisting of \$4.730 million for labor and \$4.980 million for non-labor.¹⁴⁴⁵ SCE's forecast is based on last year recorded (2018) costs plus incremental increases of:

(1) \$450,000 in labor costs primarily driven by filling existing auditor vacancies and hiring one data scientist, and (2) \$1.712 million in non-labor costs based on approximately 5,000 contract/co-sourced resource audit hours to respond to a

¹⁴⁴³ Ex. SCE-06, Vol. 4 at 26-27, 29-30.

¹⁴⁴⁴ *Id.* at 28.

¹⁴⁴⁵ Ex. SCE-06, Vol. 4 at 39, Figure III-12.

greater workload, such as the increased need to respond to wildfire mitigation- and critical business records-related work.¹⁴⁴⁶

Cal Advocates does not oppose SCE's non-labor forecast but recommends a \$781,708 reduction to SCE's labor forecast. As discussed in Section 49, below, Cal Advocates conducted a financial examination of SCE's financial data to determine whether recorded costs should be included for GRC forecasting purposes. As part of its examination of Audit costs, Cal Advocates requested that SCE provide a list of audits conducted by its Internal Auditor between 2016 and 2019 so that Cal Advocates could review a selection of its internal audit reports. In response, SCE provided a list of "privileged" audits, which SCE claimed was protected from disclosure by attorney-client privilege and/or the attorney work product doctrine, and a non-privileged list.¹⁴⁴⁷ Although Cal Advocates does not challenge SCE's assertion of legal privilege, Cal Advocates states that without access to the privileged reports, Cal Advocates could not determine whether the costs to perform the audits were justifiably assigned to ratepayers.¹⁴⁴⁸ Cal Advocates, therefore, recommends removing the costs of the privileged audits for 2018 (14 reports totaling \$781,708) from SCE's 2018 recorded expenses for purposes of determining the TY forecast.¹⁴⁴⁹

¹⁴⁴⁶ *Id.* at 41-42.

¹⁴⁴⁷ Ex. PAO-18-WP at 1-17.

¹⁴⁴⁸ Cal Advocates OB at 320.

¹⁴⁴⁹ *Id.* at 249, 320. Cal Advocates' statements that its recommendation results in a reduction of \$784,000 to SCE's forecast appear to be in error since the costs of the audits it seeks to remove from SCE's 2018 recorded expenses total \$781,708. (*Id.* at 249, 320.) Moreover, as noted below, SCE's privilege log lists only 13 (not 14) privileged audits for 2018.

Cal Advocates does not oppose SCE's incremental labor forecast of \$450,000 to fill existing vacancies and hire a data scientist.¹⁴⁵⁰

SCE provided a privilege log of its privileged audits, which included: (1) the audit title; (2) the project number; (3) the audit group that performed the audit work; (4) a brief description of scope; (5) the date of issuance of the audit report; (6) the designated Law Department counsel for the audit; and (7) the sender and all of the named recipients of the reports.¹⁴⁵¹ The privilege log lists 13 privileged audits for 2018 totaling \$730,521.¹⁴⁵² Based on our review of the privilege log, we find that the expenses for conducting the audits appear to be reasonable business expenses¹⁴⁵³ with the exception of the audit for "Third Party Review," and find it reasonable to include the expenses for these 12 privileged audit reports for purposes of determining the TY forecast.¹⁴⁵⁴ The information provided regarding the Third Party Review audit is too vague and general for the Commission to determine whether the expenses are reasonably assigned to ratepayers, and therefore, we exclude the expenses for this audit in determining the TY forecast.

¹⁴⁵⁰ *Id.* at 249-250.

¹⁴⁵¹ A copy of the privilege log with estimated audit hours and costs for each audit can be found at Ex. PAO-18-WP at 18-24.

¹⁴⁵² Ex. PAO-18-WP at 20-23.

¹⁴⁵³ The audits cover topics such as: Payroll Process and Controls, Critical Business Records and Program Review - Vegetation Management, Federal Aviation Administration Compliance, Diverse Business Enterprise Annual Report - Goal and Program Expense, and General Order 165 Inspection and Maintenance Activities.

¹⁴⁵⁴ This is consistent with our determination in the recent Sempra Utilities' GRC, where we found that privileged audits that are necessary are a legitimate expense and should not be excluded for purposes of determining the TY forecast. (D.19-09-051 at 717-718.)

Therefore, we reduce SCE's labor forecast by the costs for the Third Party Review audit (\$150,863)¹⁴⁵⁵ for a total labor forecast of \$4.579 million. We find reasonable and approve SCE's uncontested non-labor forecast of \$4.980 million.

34. Ethics and Compliance

Ethics and Compliance (E&C) provides the framework for an ethical and compliant work environment. E&C's work includes Compliance Oversight, Assessment, and Assurance, including Information Governance; Codes of Conduct, Certification, and Policy Management; Training, Communication, and Outreach; and HelpLine and Investigation.

SCE forecasts TY O&M expenses of \$14.224 million for E&C.¹⁴⁵⁶ SCE's forecast is based on last year recorded (2018) costs with an additional \$2.312 million net increase in labor and non-labor expenses to provide resources to support the ramp-up of wildfire mitigation compliance activities and to help implement the Critical Business Records Management Program.¹⁴⁵⁷ We find reasonable and approve SCE's uncontested forecast.

35. Safety Programs

The Edison Safety organization provides guidance, governance, and oversight of the company's safety programs and activities focused on public, contractor, and worker safety to accomplish the common goal of creating an injury-free workplace.

SCE forecasts TY O&M expenses of \$24.025 million to manage the Safety Programs BPE, which includes \$4.291 million for Employee and Contractor Safety, \$0.603 million for Public Safety, \$2.276 million for Safety Culture

¹⁴⁵⁵ Ex. PAO-18-WP at 22.

¹⁴⁵⁶ Ex. SCE-06, Vol. 4 at 46, Figure III-13.

¹⁴⁵⁷ *Id.* at 47-48.

Transformation, and \$16.856 million for Safety Activities – T&D.¹⁴⁵⁸ SCE’s forecasts except for the forecast for Public Safety are based on last year recorded (2018) costs with adjustments. Public Safety is a newly created group that was not officially established until late 2018, and therefore, the forecast is based on anticipated work activities, such as developing and implementing metric trees, which will be issued to evaluate public safety risks and make informed decisions; collaborating with Enterprise Risk Management; and benchmarking of industry wide public safety best practices.¹⁴⁵⁹

We find reasonable and approve SCE’s uncontested TY O&M forecast for the Safety Programs BPE.

36. Enterprise Operations

Enterprise Operations comprises the Facility and Land Operations BPE and the Transportation Services BPE. Facilities and Land Operations BPE activities involve the stewardship, acquisition, disposition, administration, and management of SCE’s electric and non-electric real estate assets across SCE’s service territory. Transportation Services BPE activities involve the management of SCE’s vehicle and equipment fleet.¹⁴⁶⁰

SCE requests \$59.277 million in 2021 TY O&M expenses and combined 2019-2023 capital expenditures of \$665.673 million for Enterprise Operations.¹⁴⁶¹

SCE’s TY O&M forecast is uncontested. TURN recommends an overall reduction of \$129.651 million to SCE’s capital expenditure forecast.

¹⁴⁵⁸ *Id.* at 60, 65, 69; Ex. SCE-06, Vol. 4E at 49, 53, 77.

¹⁴⁵⁹ Ex. SCE-06, Vol. 4 at 63-66.

¹⁴⁶⁰ SCE OB at 280-281.

¹⁴⁶¹ Includes 2019 recorded capital expenditures of \$113.384 million. SCE’s combined 2019-2021 capital expenditure forecast is \$364.981 million. (Ex. SCE-17, Vol. 5E2 at 3, Table I-3; SCE-18, Vol. 1 Appendix A at A-94.)

36.1. Enterprise Operations O&M

SCE's 2021 TY O&M forecast for the Facility and Land Operations BPE is \$59.277 million.¹⁴⁶² The forecast covers the management of building and ground conditions of SCE owned and leased properties, the planning and delivery of large facility projects, and the administration of land rights.¹⁴⁶³ SCE's forecast is based on 2018 recorded labor costs, itemized non-labor costs, and other costs based on actual payment terms of leases. Compared to 2018 recorded expenses, SCE's 2021 TY O&M request represents a \$7.582 million increase, which SCE attributes to a combination of non-labor increases and rent escalations.¹⁴⁶⁴

We find reasonable and adopt SCE's uncontested TY O&M forecast of \$59.277 million for Enterprise Operations.¹⁴⁶⁵

36.2. Enterprise Operations Capital

SCE's 2019-2023 capital expenditure request for Enterprise Operations is comprised of \$642.008 million for Facility and Land Operations and \$23.665 million for Transportation Services.¹⁴⁶⁶

The Facility and Land Operations BPE capital expenditures cover the following five programs:

¹⁴⁶² Ex. SCE-17, Vol. 5 at 2, Table I-1.

¹⁴⁶³ Ex. SCE-06, Vol. 1 at 1.

¹⁴⁶⁴ *Id.* at 23-24.

¹⁴⁶⁵ Operating costs associated with the Transportation Services BPE are embedded in the O&M and capital forecasts detailed in other volumes covering the BPEs whose activities incur those costs (including the T&D BPEs, Customer Service BPEs, and Generation and Energy Procurement BPEs), and are not separately requested as part of Enterprise Operations. (Ex. SCE-06, Vol. 5 at 108, fn. 136; SCE OB at 281, fn. 1664.)

¹⁴⁶⁶ Includes recorded 2019 capital expenditures of \$107.721 million and \$4.997 million for Facility and Land Operations and Transportation Services, respectively. (Ex. SCE-12, Vol. 1 Appendix A at A4; Ex. SCE-17, Vol. 5E2 at 2; Ex. SCE-18, Vol. 1 Appendix A at A-94.) For the 2020-2021 period, SCE forecasts \$243.317 million for Facility and Land Operations and \$8.947 million for Transportation Services. (Ex. SCE-17, Vol. 5E2 at 3, Table I-3.)

- Infrastructure Upgrades: Capital projects addressing poor facility conditions, systems that have reached the end of their life cycle or present safety or reliability risks, and facility upgrades concurrent with ongoing seismic mitigation activities. During the GRC period, includes the following infrastructure upgrades and IT infrastructure/equipment projects: Blythe Service Center; Santa Barbara Service Center; T&D Training Center; Camp Edison Buildings; Vehicle Maintenance Facilities; General Office 1 (GO1) and GO4 Workplace Upgrades; GO1 Electrical Upgrades; Fleet Charging Program; Employee Charging Infrastructure Program; Materials Supply Warehouse; Covina Customer Service Automated System Building Remodel; and CSRP training rooms.¹⁴⁶⁷
- Facility Repurpose Programs: Capital projects focusing on facilities whose conditions no longer support current business operations, due to changes in SCE equipment or operations. During the GRC period, includes renovations to the Alhambra Regional Operations Facility and Westminster Combined Facility, as well as ongoing furniture modifications and ergonomic equipment.¹⁴⁶⁸
- Substation Reliability Upgrades: Capital projects addressing aging and poor facility conditions at substation maintenance and test buildings. During the GRC period, includes improvements to the Devers and Rector Maintenance and Test Buildings.
- Facility Management Capital Programs: Addresses ongoing expenditures of updates to building systems that are either past their useful life (*e.g.*, HVAC, roof) or modifications due to regulatory or compliance requirements (*e.g.*, fire systems). During the GRC period, includes the Arc Flash Compliance Upgrade Program; Non-Electric Facilities Capital Maintenance Program; Substation Facilities Capital Maintenance Program; Energy

¹⁴⁶⁷ Ex. SCE-06, Vol. 5 at 25-64.

¹⁴⁶⁸ *Id.* at 66-73.

Efficiency Program; Safety, Compliance, Operational and Reliability Program; and seventeen various other projects that are less than \$3 million each.¹⁴⁶⁹

- Land Operations: Capital work activities associated with renewing land rights from governmental agencies. For the GRC period, includes costs to secure Master Permits with the Bureau of Land Management (BLM).¹⁴⁷⁰

SCE engaged with Cumming Construction Management, Inc. (CCMI), an international project management and construction cost consulting firm, to create independent planning estimates for each capital project. In preparing the cost estimates, CCMI used a variety of sources, including: proprietary data, industry standard data, third-party construction data and experience, current local market rates, and data provided by SCE.¹⁴⁷¹ Between 2019-2021, SCE estimates \$99.030 million for Infrastructure Upgrades; \$54.543 million for Facility Repurpose Projects; \$10.781 million for Substation Reliability Upgrades; \$165.732 million for Facility Management Capital Programs (including \$15.561 million for projects less than \$3 million each); and \$4.389 million for Land Operations.¹⁴⁷²

The Transportation Services BPE covers the management of the vehicle and equipment fleet employed for SCE's operations. The 2019-2021 capital forecast is divided into three categories: Aircraft Operations, Fleet Asset Management, and Fleet Operations and Maintenance. SCE forecasts

¹⁴⁶⁹ *Id.* at 78-79.

¹⁴⁷⁰ SCE states the transition from O&M expense to capital expenditures of government land renewal agreements began in 2017 as government agencies began requesting detailed land surveys and GIS data. (*Id.* at 106-107.)

¹⁴⁷¹ *Id.* at 25-33.

¹⁴⁷² Ex. SCE-17, Vol. 5E at 4, Table I-4.

\$13.944 million of capital expenditures from 2019-2021 for this BPE.¹⁴⁷³ Of this total, SCE forecasts \$3.418 million for the 2021 TY, which is a \$2.623 million decrease from 2018 recorded expenditures. SCE indicates the decrease is primarily driven by the absence of helicopter lease buy outs (based on the helicopter lease schedule, there are no lease buy out options in 2021), and fewer vehicle leasehold capital improvements.¹⁴⁷⁴

36.2.1. Intervenor Comments

Cal Advocates reviewed SCE's testimony and workpapers and does not oppose SCE's 2019-2021 capital forecasts for Enterprise Operations.¹⁴⁷⁵

TURN recommends a reduction of \$85.108 million in connection with four Infrastructure Upgrade Projects: (1) Blythe Service Center; (2) Santa Barbara Service Center; (3) T&D Training Center; and (4) Vehicle Maintenance Facilities. In addition, TURN recommends complete disallowance of SCE's forecast for Substation Reliability Upgrades (\$15.005 million).¹⁴⁷⁶

TURN observes that SCE is requesting \$13.213 million in the current GRC to complete the Blythe Service Center. Although SCE projected the \$13.213 million to occur in 2019, SCE only spent \$11.159 million in that period, while the Blythe Service Center has been used and useful since December 13, 2019. TURN recommends the Commission authorize no more than what was actually spent, which would reduce SCE's request by \$2.054 million.¹⁴⁷⁷

¹⁴⁷³ Including 2019 recorded costs of \$4.997 million. (Ex. SCE-17, Vol. 5E2 at 3, Table I-3; Ex. SCE-12, Vol. 1 Appendix A at A4.)

¹⁴⁷⁴ Ex. SCE-06, Vol. 5 at 109.

¹⁴⁷⁵ Ex. PAO-12 at 9.

¹⁴⁷⁶ Ex. TURN-10 at 8.

¹⁴⁷⁷ *Id.* at 8-9.

The Santa Barbara Service Center project consists of relocating the existing service center from its present location to a new location south of the city.¹⁴⁷⁸ TURN recommends the disallowance of all costs related to the Santa Barbara Service Center (\$15.123 million) for two reasons: First, TURN asserts that SCE's request is improper as the project will not be completed during this GRC period. SCE's specific request for this project is for "the acquisition of land and related costs during 2022-2023,"¹⁴⁷⁹ and TURN states that SCE has not yet purchased the land, or demonstrated it is likely it will purchase the land. Second, TURN asserts that SCE has a history of not spending authorized amounts on new service centers, including \$48.6 million that was authorized for the Santa Barbara relocation project in SCE's 2018 GRC.¹⁴⁸⁰

Similar to the Santa Barbara Center, TURN asserts that SCE's history of underspending for the T&D Training Center,¹⁴⁸¹ Vehicle Maintenance Facilities,¹⁴⁸² and the two Substation Reliability Upgrade projects (*i.e.*, Devers and Rector Maintenance and Test Buildings)¹⁴⁸³ should be considered. In the 2018 GRC, the Commission authorized \$92 million for the T&D Training Center,

¹⁴⁷⁸ Ex. SCE-06, Vol. 5 at 36-37.

¹⁴⁷⁹ Ex. TURN-49 at 3.

¹⁴⁸⁰ Ex. TURN-10 at 9-12.

¹⁴⁸¹ The T&D Training Center would provide sufficient classroom and outdoor space for training resources that mirror field conditions, leverage current technology, and meet demand for training. Completing the relocation of these training facilities would also eliminate weekend and swing shift classes arising from existing space and equipment constraints. (Ex. SCE-06, Vol. 5 at 39.)

¹⁴⁸² The Vehicle Maintenance Facilities project involves the renovation of the vehicles maintenance facilities at the Orange Coast, Montebello, and Ventura service centers, which are over 30 years old and remain the most heavily used at SCE. (*Id.* at 43-44.)

¹⁴⁸³ The Substation Maintenance and Test Building program is designed to replace temporary and outdated facilities which house electricians that perform T&D maintenance and inspections on compliance assets. (*Id.* at 78.)

\$22.646 million for Vehicle Maintenance Facilities, \$5.005 million for the Devers Maintenance and Test Building, and \$11.035 million for the Rector Maintenance and Test Building. TURN states that as of 2019 SCE had only spent \$2.132 million on the T&D Training Center, \$1.541 million on the Devers Maintenance and Test Building, \$5.195 million on the Rector Maintenance and Test Building, and had no recorded expenditures for Vehicle Maintenance Facilities.¹⁴⁸⁴

TURN also asserts that SCE failed to meet its burden to justify the cost of each project: in response to a request for additional supporting documentation, SCE provided a single page cost summary from CCMI without any specific bids, contracts, invoices, or other supporting documentation.¹⁴⁸⁵

Based on these arguments, TURN recommends complete rejection of SCE's forecasts for the T&D Training Center (\$45.258 million), Vehicle Maintenance Facilities (\$22.646 million), and Devers and Rector Maintenance and Test Buildings (\$15.005 million). Lastly, should the Commission decline TURN's recommendations for these projects, TURN recommends SCE's rebuttal position be adopted, which utilizes 2019 recorded costs which are lower than SCE's forecast.¹⁴⁸⁶

In response, SCE states that while the Blythe Service Center was in service by the end of 2019, certain invoices for construction work and municipal requirements will not be paid until 2020. To be consistent with historical practice in the GRC, SCE agrees to reduce its forecast for the Blythe Service Center to

¹⁴⁸⁴ *Id.* at 12-19; TURN OB at 233-238.

¹⁴⁸⁵ *Ibid.*

¹⁴⁸⁶ TURN OB at 229 and 236-237.

\$11.159 million; however, SCE requests it be allowed to seek recovery for remaining 2020 expenditures in the next GRC.¹⁴⁸⁷

SCE admits that there have been significant challenges in locating a suitable parcel for the Santa Barbara Service Center, but indicates it is currently working with the municipality to address zoning and permitting issues with two parcels, and continues to project completion of the acquisition and related environmental studies by 2023 as forecast. SCE also asserts that FERC and Commission authorities provide that land purchased in anticipation of future requirements be included in rates, including when land is purchased in advance of the construction of utility assets thereupon; that the Commission found the relocation of the Santa Barbara Service Center to be justified in SCE's 2018 GRC decision; and that during the delay SCE prioritized expenditures for other Facility and Land Operations BPE projects that emerged in 2018 to address safety and compliance issues.¹⁴⁸⁸

SCE states the prior iteration of the T&D Training Center approved in the 2018 GRC was to purchase new land for the project. After determining the selected sites were too costly or unworkable, SCE is now planning to utilize SCE-owned land in Rancho Vista. SCE asserts that planning and engineering activities for this project are on track based on the updated scope and forecast presented in this GRC; that during the delay SCE prudently applied funds to perform other emerging and beneficial projects; and that SCE provided reasonable cost justification, including a detailed breakdown of CCMI's planning

¹⁴⁸⁷ Ex. SCE-17, Vol. 5 at 6-7.

¹⁴⁸⁸ *Id.* at 8-11; SCE OB at 283-284.

estimate containing line-by-line division activity, quantity, unit of measure, unit cost, and activity cost total.¹⁴⁸⁹

SCE indicates the Vehicle Maintenance Facilities project was delayed following benchmarking analyses with other utilities, while the Devers and Rector Maintenance and Test Buildings were delayed resulting from bids far exceeding the forecast. SCE also cites to scope modifications, site studies, and local public use permitting requirements as being the causes for delay of the Devers Maintenance and Test Buildings. SCE asserts it supplied adequate supporting detail for all these projects, including a detailed breakdown of CCMi's planning estimate containing line-by-line division activity, quantity, unit of measure, unit cost, and activity cost total. Lastly, SCE states that construction is well underway for the Devers and Rector Maintenance and Test Buildings and both are on track for completion in 2020.¹⁴⁹⁰

36.2.2. Discussion

With the acceptance of TURN's proposed \$2.054 million reduction, SCE's revised forecast of \$11.159 million for the Blythe Service Center is uncontested.¹⁴⁹¹ We find SCE's revised forecast for this project to be reasonable and confirm that the adoption of this revised forecast does not preclude SCE from seeking recovery of the final construction and municipal invoice payments for the project, which were delayed in being provided to SCE.

As discussed in Section 40.1, while the Commission has on numerous occasions reduced or disallowed costs of activities that were requested and

¹⁴⁸⁹ Ex. SCE-17, Vol. 5 at 11-15.

¹⁴⁹⁰ *Id.* at 15-24.

¹⁴⁹¹ TURN RB at 105.

included in prior GRC authorizations,¹⁴⁹² the question of whether to approve a renewed funding request is fact-specific and must be evaluated on a case-by-case basis. Therefore, we consider each funding request individually. As the applicant, SCE bears the burden to establish the reasonableness of its decision to reprioritize or divert funding, and of its renewed request for funding.

In SCE's 2018 GRC, the Commission found that SCE justified its proposal to relocate its Santa Barbara Service Center on the basis that the reduction in employee travel time would result in the dual benefits of shorter outages in the Santa Barbara area, as well as higher retention rates for SCE's employees.

However, the Commission also stated:

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.¹⁴⁹³

SCE states that it identified 40 parcels of appropriate size to consider for this project, narrowed the list down to three sites near Carpinteria, California, before determining the locations were unworkable due to zoning, environmental conditions, or endangered species restrictions. SCE subsequently identified a different potential site before determining the site could not be re-zoned for industrial or commercial use.¹⁴⁹⁴ SCE provides adequate support to demonstrate it has been actively engaged in finding a site to relocate the Santa Barbara Service Center, while many of the project delays appear to be outside of SCE's control;

¹⁴⁹² D.15-11-021 at 346; D.07-03-044 at 94-95.

¹⁴⁹³ D.19-05-020 at 222.

¹⁴⁹⁴ Ex. SCE-06, Vol. 5 at 36-37.

therefore, we do not find it necessary at this time to place the financial responsibility for this project on SCE's shareholders.

However, we are also not convinced that SCE is in a better position to secure a new site for the Santa Barbara Service Center than it was in the last GRC. SCE does not provide any assurances that it is any closer to securing a site, and merely states that it "continues to work with a local broker to identify a parcel suitable for sustaining service center operations."¹⁴⁹⁵ While SCE is investigating two potential sites for the new service center, neither have been determined to be acceptable.¹⁴⁹⁶ Given the unique challenges in locating a suitable parcel for this project,¹⁴⁹⁷ we will not provide further funding for this project until a site has been secured.

The need for the T&D Training Center is undisputed. We find SCE has provided sufficient justification to support the need for upgraded training facilities, which include sufficient classroom and outdoor space to eliminate existing weekend and swing shift classes arising from space and equipment constraints. Further, we find that SCE reasonably considered all alternatives.¹⁴⁹⁸ There also does not appear to be any reason to suspect this project will continue to be delayed, since SCE has now secured a site for the new training center and has commenced planning and engineering work for the project.¹⁴⁹⁹ Finally, we have reviewed the cost information provided by CCMI, which is broken down

¹⁴⁹⁵ *Id.* at 37.

¹⁴⁹⁶ Ex. TURN-10 at 11-12.

¹⁴⁹⁷ Ex. SCE-17, Vol. 5 at 9.

¹⁴⁹⁸ Including the acquisition of new land, continuing to address new training requirements in an ad hoc manner, or retain third-party providers for training. (See Ex. SCE-06, Vol. 5 at 39-40.)

¹⁴⁹⁹ Ex. SCE-17, Vol. 5 at 13.

by construction costs, furniture, fixtures and equipment costs, and pre-construction activities,¹⁵⁰⁰ and find the estimate both sufficiently detailed and the overall cost levels reasonable. Therefore, we approve SCE's 2019 recorded and 2020-2021 capital expenditure forecast for the T&D Training Center, and expect the project to move forward as planned.

The need for SCE's proposed Vehicle Maintenance Facilities project is similarly undisputed. We find SCE's justifications for the project, including that the three vehicle maintenance facilities are heavily used, over 30 years old, and do not accommodate the size and weight of the newer T&D trucks,¹⁵⁰¹ to be compelling. However, we are not convinced that SCE will move forward with this project within the timeline presented. The delays associated with this project have been entirely within SCE's control, while SCE did not record any expenditures for the project as of the end of 2019. Beyond stating that it has focused on long-term solutions and continues to move this project forward,¹⁵⁰² SCE provides no actual evidence to support its assertions, and we will not authorize additional funding for this project without some showing that progress has been made. Therefore, SCE's funding request for the Vehicle Maintenance Facilities project is denied.

Lastly, the need for the Devers and Rector Maintenance and Test Buildings is similarly undisputed. The Devers and Rector substations account for two of the three substations with the highest Facility Condition Index Score (FCI),¹⁵⁰³

¹⁵⁰⁰ *Id.*, Appendix A at A32-A33.

¹⁵⁰¹ Ex. SCE-06, Vol. 5 at 43-44.

¹⁵⁰² Ex. SCE-17, Vol. 5 at 16-17.

¹⁵⁰³ FCI is a standard facility management benchmark used to assess the current and projected condition of a building asset, and is expressed as a ratio of current year renewable cost to current building replacement value. (Ex. SCE-06, Vol. 5 at 4-5 and 78.)

and we agree that the age and condition of the facilities support the requested improvements. Further, SCE has demonstrated continual progress on both projects, including recorded expenditures from 2016 through the present and significant project construction.¹⁵⁰⁴ Lastly, we have reviewed the breakdown of CCMI's planning estimate for the Devers and Rector Maintenance and Test Buildings and find the estimate sufficiently detailed and supported, and the estimated level of costs reasonable. Therefore, we approve SCE's 2019 recorded and 2020-2021 capital expenditure forecast for the Devers and Rector Maintenance and Test Buildings.

We find reasonable and adopt SCE's remaining uncontested forecasts for Facility and Land Operations and Transportation Services. Accounting for the removal of SCE's forecasts for the Santa Barbara Service Center and Vehicle Maintenance Facilities projects results in an approved 2019-2021 capital expenditure amount of \$351.038 million for Facility and Land Operations. The approved 2019-2021 capital expenditure budget for the Transportation Services BPE is \$13.944 million.

37. Policy and External Engagement

SCE's Policy and External Engagement BPE is comprised of the activities that support and implement energy, environmental, and wildfire mitigation policies, as well as other policies instituted by state, federal, and local agencies. These activities include case management of all proceedings before state and federal regulatory agencies; submission of regulatory filings; participation in joint actions of state agencies; and educating government officials, staff, and local community stakeholders on policy initiatives and programs.

¹⁵⁰⁴ Ex. SCE-17, Vol. 5 at 20-23.

SCE forecasts \$24.816 million in TY O&M expenses for the Policy & External Engagement BPE. This forecast includes work for the following activities:¹⁵⁰⁵

Activity	TY Forecast (\$000)
Develop and Manage Policy and Initiatives	15,822
Education, Safety, and Operations	7,114
Professional Development and Education	1,880
Total	24,816

SCE's TY forecast of \$7.114 million for the Education, Safety, and Operations activity is uncontested. This GRC activity consists of work performed within the Local Public Affairs organization, which is responsible for managing and directing external engagement with government officials, staff, business, and local community stakeholders. SCE's forecast is based on 2018 recorded costs with increases of \$143,000 in labor expense to account for the filling of vacancies that were left unfilled in 2018¹⁵⁰⁶ and \$204,000 in non-labor expense to account for increased work expected related to stakeholder engagement on public safety, emergency response, and clean energy initiatives.¹⁵⁰⁷ We find reasonable and approve the uncontested forecast.

Cal Advocates proposes reductions for the other two activity forecasts, which are discussed below.

¹⁵⁰⁵ Ex. SCE-17, Vol. 6 at 2, Table I-1.

¹⁵⁰⁶ SCE applies a 75 percent/25 percent ratepayer/shareholder allocation to derive the labor forecast based on a time tracking study. (Ex. SCE-06, Vol. 6 at 18.)

¹⁵⁰⁷ *Id.* at 12-13, 18.

37.1. Develop and Manage Policy and Initiatives

The Develop and Manage Policy and Initiatives GRC activity consists of work performed within the Regulatory Affairs organization. This work is organized into seven functions: (1) Case Management, which is responsible for managing regulatory proceedings; (2) Case Administration, which provides administration support to Case Management; (3) CPUC Engagement; (4) CAISO/FERC/CEC Engagement; (5) Clean Energy Engagement Coordination; (6) Environmental Affairs – State, Local, Federal; and (7) Pricing Design and Research.¹⁵⁰⁸

SCE forecasts \$15.822 million in TY O&M expenses for Develop and Manage Policy and Initiative activities, consisting of \$14.653 million in labor and \$1.169 million in non-labor.¹⁵⁰⁹ SCE's labor forecast is based on 2018 recorded expenses with an upward adjustment of \$358,000 to account for an anticipated increase in regulatory activities in 2021 and for filling vacancies that were left unfilled in 2018 and 2019. SCE's non-labor forecast is based on 2018 recorded expenses with an upward adjustment of \$118,000 to account for the expected increase in regulatory activities in 2021. According to SCE, its non-labor forecast of \$1.169 million reflects SCE's removal of \$92,262 from its 2018 non-labor recorded expenses based on Cal Advocates' recommendations.¹⁵¹⁰

Cal Advocates does not oppose SCE's forecast labor expenses but recommends a reduction to SCE's forecast non-labor expenses. Based on the results of its financial examination, discussed in Section 49, Cal Advocates recommends reducing SCE's 2018 recorded non-labor expenses by \$181,524 for

¹⁵⁰⁸ *Id.* at 6-9.

¹⁵⁰⁹ Ex. SCE-17, Vol. 6E at 4, Table II-2.

¹⁵¹⁰ *Id.* at 6.

the following costs that were identified as one-time or could not be independently verified due to SCE's assertion of legal privilege:¹⁵¹¹

Item #	Transaction	Amount	Reason for Adjustment
1	Fees paid for Solar Energy Conference and CA Air Quality Board's 50 th Technology Symposium and Showcase	\$7,500	One-time cost
2	Research study on solar energy and messaging	\$124,524	One-time cost
3	Study on Disadvantaged Community Activities	\$22,500	One-time cost
4	Analysis Group	\$27,000	SCE objects to providing invoice on grounds that document is attorney work product. Cal Advocates is unable to determine if work performed benefits ratepayers.
	Total Adjustment	\$181,524	

In rebuttal, SCE agreed to remove the costs for item numbers 1 and 3 from its 2018 recorded costs because each is a one-time or non-recurring cost.¹⁵¹² SCE also agreed to remove half the costs of item number 2. SCE argues that removal of half the amount is appropriate because the total expense was originally allocated 50 percent to customers and 50 percent to shareholders, and therefore, only half the costs were included in the 2018 recorded expenses.¹⁵¹³ SCE opposes the removal of the expense for item number 4 from the 2018 recorded costs. Although SCE declined to provide a copy of the invoice based on its assertion of

¹⁵¹¹ Ex. PAO-18 at 8, Table 18-3.

¹⁵¹² Ex. SCE-17, Vol. 6 at 5.

¹⁵¹³ *Ibid.*

legal privilege, SCE explains that the cost represents payment for service related to the examination of regulatory and legislative issues associated with the growth of CCA and its impacts on the utilities and utility customers, which helped SCE identify potential solution sets concerning the appropriate and equitable cost allocation for above-market generation portfolio costs.¹⁵¹⁴ SCE argues that these costs are appropriately included in recorded expense for the GRC activity, and that removal of the historical costs would deny SCE the full rights of the privilege.¹⁵¹⁵

We agree with Cal Advocates and SCE that the costs for items 1 and 3 (totaling \$30,000) should be excluded from 2018 recorded costs. We agree with SCE that half of the costs for item 2 (\$62,262) should be excluded because only half of the costs of the study were allocated to ratepayers and included in SCE's recorded expenses. With respect to item 4, there is no dispute that the invoice contains privileged material. Based on SCE's description and purpose of the services provided, we agree that it is reasonable to include these costs in the 2018 recorded costs for purposes of forecasting the TY forecast.¹⁵¹⁶ Based on the foregoing, we find that the recorded 2018 expenses of \$1.143 million should be adjusted downward by \$92,262 resulting in adjusted 2018 recorded expenses of \$1.051 million.

SCE's labor and non-labor forecasts are based on last year recorded costs plus adjustments. Although the adjustments are uncontested, we find that SCE has failed to provide adequate justification for an increase above last year recorded costs. SCE asserts that the upward adjustments are justified because it

¹⁵¹⁴ Ex. SCE-17, Vol. 6, Appendix A at A-5.

¹⁵¹⁵ Ex. SCE-17, Vol. 6E at 6.

¹⁵¹⁶ See also discussion in Audit Services (Section 33).

anticipates an increase in regulatory activities but provides no details regarding this anticipated work. SCE's aggregate O&M expenses for this activity have declined by 29 percent between 2014-2018 and have declined each year for the past 3 recorded years.¹⁵¹⁷ In 2018, SCE's O&M expenditures were \$1.958 million lower than authorized.¹⁵¹⁸ Given these considerations, we find it reasonable to approve a TY forecast of \$15.346 million based on last year recorded costs, consisting of \$14.295 million in labor and \$1.051 million in non-labor.

37.2. Professional Development and Education

The Professional Development and Education GRC activity consists of customer-funded dues and memberships, which help SCE stay current on industry trends and best practices. SCE forecasts TY expenses of \$1.880 million for this activity.¹⁵¹⁹ SCE's forecast is based on an itemized list of anticipated corporate membership dues. SCE contends that it excluded the portions of those dues attributable to lobbying and non-allowable expenses.¹⁵²⁰

Cal Advocates recommends a reduction of \$1.669 million to SCE's forecast based on the removal of dues for SCE's Edison Electric Institute (EEI) membership. In SCE's 2018 GRC, the Commission denied ratepayer funding of SCE's EEI membership because it found that SCE had not provided sufficient evidence to meet its burden to establish that EEI dues should be recovered from

¹⁵¹⁷ Ex. SCE-06, Vol. 6 at 10.

¹⁵¹⁸ *Id.* at 9.

¹⁵¹⁹ *Id.* at 29-30.

¹⁵²⁰ SCE's forecast includes membership dues for: Edison Electric Institute, California Utilities Emergency Association, Center for Energy Workforce Development, The Center for Economic Development/Southern California Leadership Council, The Conference Board, and Western Energy Institute. (*Id.* at 19-27.)

ratepayers.¹⁵²¹ Cal Advocates argues that SCE has similarly failed to meet its burden in this proceeding.¹⁵²²

EEI is an association of U.S. investor-owned electric companies, international affiliates, and industry associates. SCE contends that access to EEI's networks, data, expertise, conferences, and workshops allows SCE to streamline, improve, and reduce costs of internal processes to provide better and safer service.¹⁵²³ SCE presents examples of the benefits that customers receive from this membership, including: (1) disaster preparedness through mutual assistance agreements and programs, which brings quick power and safety restoration to customers during an emergency; (2) grid resiliency, leading to safe and reliable electric service for customers; (3) customer savings, resulting from EEI workshops and resources that help SCE keep rates affordable; (4) information exchange, such as forums which cut down SCE's coordination, compliance, and consulting costs, which result in customer savings; and (5) miscellaneous activities that benefit SCE customers through improved quality, safety, and rates.¹⁵²⁴ SCE states that its requested funding for its EEI membership does not include the portion of fees attributable to lobbying and non-allowable expenses, which SCE bases on information provided on the EEI invoice.¹⁵²⁵

It has generally been the Commission's policy to deny ratepayer funding of EEI dues unless a utility provides sufficient evidence to establish clear

¹⁵²¹ D.19-05-020 at 250.

¹⁵²² Cal Advocates OB at 255.

¹⁵²³ Ex. SCE-06, Vol. 6 at 19.

¹⁵²⁴ *Id.* at 19-25.

¹⁵²⁵ Ex. SCE-17, Vol. 6 at 9 and Appendix B at B-3.

ratepayer benefits.¹⁵²⁶ The Commission has specifically barred ratepayer funding of membership activities such as: legislative advocacy, legislative policy research, regulatory advocacy, advertising, marketing, and public relations.¹⁵²⁷

In this case, SCE has presented sufficient evidence demonstrating that ratepayers receive some benefits from the EEI membership. However, SCE does not provide a breakdown of EEI's membership activities or dues that would enable the Commission to determine how much of the dues are attributable to activities the Commission has previously deemed improper for ratepayer recovery. SCE relies on information presented in the EEI invoice to exclude costs related to "influencing legislation," but the invoice does not present an itemized breakdown of other activities that the Commission has excluded from ratepayer funding. The Commission has previously found that "the EEI invoice ... is insufficient evidence to establish the portion of the invoice which should be recovered from ratepayers."¹⁵²⁸

Given SCE's demonstration that there are some ratepayer benefits, we find it reasonable to approve some ratepayer funding for SCE's EEI membership dues. Based on the EEI invoice provided by SCE, we find it reasonable to approve the dues designated for Restoration, Operations, and Crisis Management Program (\$0.015 million).¹⁵²⁹ In line with amounts we have previously found to be reasonable,¹⁵³⁰ we find it reasonable to approve ratepayer

¹⁵²⁶ See D.20-07-038 at 6.

¹⁵²⁷ D.15-11-021 at 365-366; D.14-08-032 at 261-262.

¹⁵²⁸ D.19-05-020 at 25; *see also* D.20-07-038 at 7.

¹⁵²⁹ Ex. SCE-17, Vol. 6, Appendix B at B-3.

¹⁵³⁰ See, e.g., D.20-07-038 at 7 (approving 50 percent of base year costs plus incremental costs); D.15-11-021 at 363, 366 (approving approximately 52 percent of total dues); D.14-08-032 at 261-262 (approving approximately 56.7 percent of total dues).

funding for 50 percent of the remainder of the dues (\$0.968 million).¹⁵³¹

Therefore, we approve a total of \$0.983 million for EEI dues. We also find reasonable and approve the remainder of SCE's uncontested forecast (\$0.211 million) for the Professional Development and GRC activity.

38. Pricing and Ratemaking

The Pricing and Ratemaking BPE includes work performed in the Regulatory Affairs organization that manages the recovery of SCE's revenue requirement authorized by the Commission and FERC. This BPE's work activities include calculating all the CPUC- and FERC-jurisdictional revenue requirements, managing memo and balancing accounts, preparing advice letters and tariffs that govern cost recovery and terms of service for SCE's customers, and sponsoring testimony on behalf of SCE.

SCE forecasts TY O&M expenses of \$5.120 million for Pricing and Ratemaking, consisting of \$4.111 million in labor expense and \$1.009 million in non-labor expense.¹⁵³² SCE's forecast is based on last year recorded (2018) costs with upward adjustments of \$59,000 in labor expense to reflect the net effect of staffing changes and \$67,000 in non-labor expense to account for anticipated levels of activities such as the use of outside contract services.¹⁵³³

SCE's forecast is uncontested. SCE does not provide a detailed explanation for its proposed adjustments to last year recorded costs. However, SCE's expenses for this BPE have varied between 2014-2018¹⁵³⁴ and we find SCE's

¹⁵³¹ These dues are for the Regular Activities of Edison Electric Institute (\$1.760 million) and Industry Issues (\$0.176 million). (Ex. SCE-17, Vol. 6, Appendix B at B-3.)

¹⁵³² Ex. SCE-06, Vol. 6 at 34.

¹⁵³³ *Id.* at 35.

¹⁵³⁴ *Id.* at 34, Figure III-11.

forecast to be within a reasonable range in consideration of the historical costs for this period. Therefore, we approve SCE's uncontested forecast.

39. GRC-Related Balancing and Memorandum Account Proposals

39.1. Contested Proposals

SCE proposes to establish three new balancing accounts in this proceeding: (1) the Wildfire Risk Mitigation Balancing Account (WRMBA) to record costs for wildfire mitigation-related activities; (2) the Vegetation Management Balancing Account (VMBA) to record costs for routine and wildfire-related vegetation management activities; and (3) the Risk Management Balancing Account (RMBA) to record insurance premium expenses for wildfire liability coverage. The proposed WRMBA is addressed in Section 17.13, the VMBA is addressed in Section 16.5, and the RMBA is addressed in Section 29.1.4.

39.2. Uncontested Proposals

The following SCE proposals to establish, eliminate, continue, or recover balances from various memorandum and balancing accounts are uncontested.¹⁵³⁵

39.2.1. Emergency Customer Protections Memorandum Account (ECPMA)

The ECPMA tracks costs related to providing emergency customer protections for customers affected by disasters declared a state of emergency by the Governor. SCE requests to transfer the December 31, 2020 balance in the ECPMA to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels. SCE has recorded \$54,000 in the ECPMA through June 2019 and as of the date of SCE's update testimony, there

¹⁵³⁵ SCE's proposals are set forth in Ex. SCE-07, Vol. 1A2.

has been negligible activity in the account.¹⁵³⁶ We approve SCE's unopposed request.

**39.2.2. Integrated Distributed Energy Resources
Administrative Costs Memorandum Account
(IDERACMA) and Distribution Deferral
Administration Costs Memorandum Account
(DDACMA)**

The IDERACMA tracks costs incurred for the IDER Incentive Pilot approved in D.16-12-036. The DDACMA tracks incremental administrative costs associated with the Distribution Investment Deferral Framework Request for Offers related procurement activities. SCE requests to transfer the ending December 31, 2020 IDERACMA and DDACMA balances, including accrued interest, to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels. SCE estimates it will record a total of \$0.616 million (excluding interest) in these two memorandum accounts over the January 1, 2018 through December 31, 2020 period.¹⁵³⁷ We approve SCE's unopposed request.

39.2.3. Rule 20A Balancing Account

The Rule 20A Balancing Account tracks the annual capital and expense costs for Rule 20A undergrounding projects. SCE proposes to maintain the balancing account and in rebuttal testimony, agreed with TURN's proposal to reduce the forecast Rule 20A capital expenditures by the estimated balance in the balancing account. The Rule 20A Balancing Account is addressed in Rule 20A Conversions (Section 14.2.2).

¹⁵³⁶ Ex. SCE-18, Vol. 1 at 20; Ex. SCE-52A2E2 at 13, fn. 11.

¹⁵³⁷ Ex. SCE-52A2E2 at 14.

39.2.4. Aliso Canyon Energy Storage Balancing Account (ACESBA)

The ACESBA tracks costs associated with the procurement of energy storage due to a moratorium of gas injections into the Aliso Canyon Natural Gas Storage Facility. SCE has procured energy storage systems from Tesla Motors and General Electric. In this GRC, SCE included the capital and O&M expenses associated with these systems in its forecasts for 2021-2023 and no longer needs to record the revenue requirement for these projects in the ACESBA.¹⁵³⁸ We approve SCE's uncontested proposal to eliminate the ACESBA.

39.2.5. Residential Rate Implementation Memorandum Account (RRIMA)

D.15-07-001 authorized SCE to establish the RRIMA to track incremental costs associated with time-of-use (TOU) pilots, TOU studies, community outreach programs, and other expenditures associated with implementing D.15-07-001 requirements. In D.19-07-004, the Commission extended the RRIMA through 2023. SCE requests that the RRIMA be extended through 2024 to align the closing of RRIMA with the end of the 2021 GRC cycle.¹⁵³⁹ We approve SCE's unopposed request to continue the RRIMA until the end of the 2021 GRC cycle.

39.2.6. Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA)

The two-way PLDPBA records the difference between: (1) recorded capital-related revenue requirements for the Pole Loading Program and Deteriorated Pole Program; (2) O&M expenses for the Pole Loading Program; and (3) the authorized Pole Programs revenue requirement as adopted in D.19-05-020. The level of cost recovery for this BA was capped at 15 percent

¹⁵³⁸ Ex. SCE-07, Vol. 1A2 at 41.

¹⁵³⁹ Ex. SCE-18, Vol. 1 at 23.

above authorized levels in both SCE's 2015 and 2018 GRCs.¹⁵⁴⁰ SCE proposes to continue the PLDPBA over the 2021 GRC cycle. SCE's proposal is addressed in Distribution and Transmission Pole Replacements (Section 15.2.1).

39.2.7. 2018 Tax Accounting Memorandum Account (TAMA)

The two-way 2018 TAMA records revenue differences resulting from the income tax expenses forecasted in the 2018 GRC and the income tax expenses incurred during the 2018 GRC period. SCE proposes to extend all applicable provisions of the 2018 TAMA for years 2021 through 2024. This proposal is addressed in Taxes (Section 44).

39.2.8. CARE Balancing Account

In D.16-11-022 the Commission directed utilities to include cooling center costs in their next GRC proceedings rather than recover these costs via low-income program dollars.¹⁵⁴¹ Consistent with this direction, SCE has included the costs associated with cooling center activities in its O&M expense forecasts and proposes to no longer record the cooling center costs in the CARE balancing account.¹⁵⁴² SCE's uncontested proposal to remove recovery of cooling center costs from Preliminary Statement Part AA, CARE, is approved.

39.2.9. Z-Factor Memorandum Account (ZFMA)

SCE proposes to add a Z-Factor memorandum account to its authorized Post Test-Year Ratemaking (PTYR) mechanism to allow it to track costs associated with potential Z-Factor events and protect against retroactive ratemaking. As discussed in PTYR (Section 46), we approve SCE's request to

¹⁵⁴⁰ Ex. SCE-07, Vol. 1A2 at 42-43.

¹⁵⁴¹ D.16-11-022 at 333.

¹⁵⁴² Ex. SCE-07, Vol. 1A2 at 46.

continue the Z-Factor mechanism. We also approve SCE's uncontested request to establish the ZFMA to track costs associated with Z-Factor events.

39.2.10. Post-Retirement Benefit Other Than Pensions Balancing Account (PBOPBA)

SCE proposes to continue the two-way PBOPBA through the 2021 GRC cycle to record the difference between authorized and actual PBOP expenses. No parties contested SCE's proposal while Cal Advocates supports it.¹⁵⁴³ We approve SCE's unopposed request.

39.2.11. Pension Cost Balancing Account (PCBA)

SCE proposes to continue the two-way PCBA through the 2021 GRC cycle to record the difference between authorized and actual pension expenses. No parties contested this proposal while Cal Advocates supports it.¹⁵⁴⁴ We approve SCE's unopposed request.

39.2.12. Medical Programs Balancing Account (MPBA)

SCE requests to continue the two-way MPBA through the 2021 GRC cycle to record the difference between authorized and actual medical, dental, and vision expenses. No parties contested this proposal while Cal Advocates supports it.¹⁵⁴⁵ We approve SCE's unopposed request.

39.2.13. Short-Term Incentive Program Memorandum Account (STIPMA)

SCE proposes to continue the one-way STIPMA through the 2021 GRC cycle to record the difference between authorized and actual STIP expenses. Any over-collections in the STIPMA are returned to customers while

¹⁵⁴³ Ex. PAO-11 at 10.

¹⁵⁴⁴ *Ibid.*

¹⁵⁴⁵ *Id.* at 10-11.

under-collections are not recoverable. SCE's uncontested request to continue the one-way STIPMA is approved.

40. Other Ratemaking Proposals

40.1. Renewed Requests for Project Funding

Cal Advocates and TURN recommend that the Commission reduce or deny SCE's funding requests for a number of capital projects that were previously requested and authorized in prior GRCs.¹⁵⁴⁶ SCE argues that it did not initiate or complete these projects for various reasons and that it would be inequitable to require shareholders to fund these projects merely because they were previously authorized.¹⁵⁴⁷ SCE argues that such a result would be a departure from established ratemaking principles and strip utility management of the necessary discretion to reprioritize spending when responding to realities and changed circumstances that cannot be perfectly forecast in a test year.¹⁵⁴⁸

In the past, the Commission has affirmed the utility management's prerogative and responsibility to provide safe and reliable service by reprioritizing and deferring activities as necessary but has also found that this management flexibility is not absolute and that the Commission must be assured that the process is reasonable.¹⁵⁴⁹ The Commission has on numerous occasions reduced or disallowed costs of activities that were requested and included in prior GRC authorizations, deferred, and re-requested in another GRC.¹⁵⁵⁰

¹⁵⁴⁶ Examples of these capital projects include grid modernization investments, the San Gorgonio decommissioning project, and various Facility and Land Operations projects.

¹⁵⁴⁷ SCE OB at 306.

¹⁵⁴⁸ *Id.* at 306-307.

¹⁵⁴⁹ *See, e.g.*, D.12-11-051 at 12; D.11-05-018 at 29.

¹⁵⁵⁰ *See, e.g.*, D.15-11-021 at 346; D.07-03-044 at 94-95.

The question of whether to approve a renewed funding request is highly fact-specific and something that the Commission evaluates on a case-by-case basis. Rather than impose a blanket rule, we evaluate each renewed funding request to determine whether there is adequate justification for the deferral and for the additional funding request. As with all other aspects of its application, SCE, as the applicant, bears the burden to establish the reasonableness of its decision to defer projects and reprioritize funding, and of its renewed request for funding.

40.2. Review of Mobilehome Park Costs

In D.14-03-021, the Commission authorized a three-year pilot program (the Mobilehome Park Utility Upgrade Program) to convert mobilehome parks and manufacturing housing communities (collectively, MHPs) with master-metered natural gas and electricity service to direct utility service. In Resolutions E-4878 and E-4958, the Commission authorized participating utilities to extend the pilot with modifications, authorized the utilities to record program costs in a balancing account, and directed that the reasonableness review of the costs would occur in a GRC.

From inception of the pilot through December 31, 2018, SCE incurred approximately \$136.0 million in costs consisting of approximately \$133.6 million in capital expenditures and \$2.4 million in O&M expense.¹⁵⁵¹ During this period, SCE converted a total of 9,050 spaces within 171 MHPs at an average cost of \$14,800 per space (excluding O&M expense) compared to the projected cost of \$22,319 per space.¹⁵⁵² SCE's cost recovery proposal is unopposed. Cal Advocates

¹⁵⁵¹ Ex. SCE-07, Vol. 1A2 at 62, Table V-14.

¹⁵⁵² *Id.* at 60.

reviewed invoices and other supporting documentation for a selection of SCE's MHP Pilot Program costs and does not oppose SCE's total recorded costs.¹⁵⁵³ We find reasonable and approve SCE's recorded costs.

41. Other Operating Revenue

Other Operating Revenue (OOR) are revenues received by SCE from transactions not directly associated with the sale of electric energy and are recorded in FERC Accounts 450 through 456. OOR reduces the revenue that must be collected through customer rates, and therefore, is subtracted from total operating costs to determine the TY revenue requirement.

SCE forecasts total OOR of \$217.749 million for the TY.¹⁵⁵⁴ SCE's TY forecast is itemized as follows:

¹⁵⁵³ Cal Advocates OB at 257-259.

¹⁵⁵⁴ Ex. SCE-54 at 277.

FERC Account		TY Forecast (Nominal \$000)
450.000 - Forfeited Discounts	Customer Service Operations OOR	11,430
451.000 - Miscellaneous Service Revenues	Customer Service Operations OOR	9,294
	T&D OOR	586
453.000 - Sales of Water and Water Power	Financial and Other Miscellaneous Revenues	0
454.000 - Rent from Electric Property	T&D OOR	63,169
	Financial and Other Miscellaneous Revenues	0
456.000 - Other Electric Revenue	Customer Service Operations OOR	3
	Customer Service and Information (CS&I) Tariffed Products and Services OOR	4,018
	T&D OOR	81,855
	Financial and Other Miscellaneous Revenues	29,688
Gains/Losses on Sale of Property		1,034
Gross Revenue Sharing Mechanism Authorized Threshold		16,672
Total		217,749

SCE's Customer Service Operations and CS&I Tariffed Products and Services OOR forecasts are addressed in Customer Interactions (Section 19.3), above and Settlements (Section 52), below.

With the exception of its forecast revenues for Added/Interconnection Facilities, SCE's forecasts for T&D OOR are addressed in T&D Other Costs and OOR (Section 18.2). SCE's forecasts for Added/Interconnection Facilities are addressed below.

SCE's forecast of \$29.688 million for Financial and Other Miscellaneous Revenue in Account 456 is uncontested. These revenues include revenues associated with the tax gross-up on Contributions in Aid of Construction and

Solar Grant Amortization.¹⁵⁵⁵ We find reasonable and approve SCE's uncontested forecast.

SCE's forecast of \$1.034 million in revenues for gains and losses on sale of property is uncontested. SCE allocates gains and losses on minor sales of property between customers and shareholders pursuant to Commission policy.¹⁵⁵⁶ SCE uses a three-year recorded (2016-2018) average for its forecast of annual customer gains/losses.¹⁵⁵⁷ We find reasonable and approve this uncontested forecast.

41.1. Non-Tariffed Products and Services

Non-tariffed products and services (NTP&S) are products and services, other than traditional electric utility services, provided by SCE that make secondary or complementary use of available capacity in utility assets and personnel. SCE shares gross revenues from NTP&S between customers and shareholders based upon pre-established sharing percentages after an initial \$16.672 million annual revenue threshold has been met, referred to as the gross revenue sharing mechanism (GRSM).¹⁵⁵⁸ Under the GRSM and Affiliate Transaction Rules, all incremental costs for NTP&S are the sole responsibility of

¹⁵⁵⁵ Ex. SCE-07, Vol. 1A2 at 98; Ex. SCE-07, Vol. 2A at 48-49.

¹⁵⁵⁶ Ex. SCE-07, Vol. 2A at 18-19.

¹⁵⁵⁷ *Id.* at 19.

¹⁵⁵⁸ The initial \$16.672 million threshold is credited back to customers on an annual basis as a revenue requirement and is not shared with shareholders. After the \$16.672 million threshold has been met, Incremental Gross Revenues from NTP&S categories designated as "Active" are shared between shareholders and customers on a 90/10 percentage basis. For NTP&S categories designated as "Passive," the Incremental Gross Revenues are shared between shareholders and customers on a 70/30 percentage basis. (Ex. SCE-18, Vol. 1 at 44-45.)

SCE's shareholders.¹⁵⁵⁹ SCE did not propose any changes to its NTP&S offerings or the GRSM in its direct testimony.¹⁵⁶⁰

Although TURN raises various arguments regarding NTP&S, reconsideration of the authorized GRSM threshold is not within the scope of this proceeding.¹⁵⁶¹ Therefore, we approve SCE's inclusion of the previously authorized \$16.672 million threshold in the OOR forecast. TURN's arguments regarding NTP&S are addressed below.

41.1.1. TURN

TURN makes several allegations against Edison Carrier Solutions (ECS), a department within SCE's Customer Service organization unit that offers telecommunications services on a non-tariffed basis. While TURN's analysis and recommendations focus largely on ECS, TURN states the issues it identifies apply to most, if not all, of SCE's NTP&S offerings.¹⁵⁶²

TURN provides the following arguments: first, TURN asserts that ECS has never compensated ratepayers or the utility for use of SCE resources, which has resulted in ECS realizing significant profit margins at levels unheard of in the telecommunications sector. TURN equates these profit levels to ECS's use of ratepayer funded human resources (HR), IT, legal/regulatory, and office-related resources. TURN further asserts that SCE has not provided examples or

¹⁵⁵⁹ See D.97-12-088, as modified by D.06-12-029.

¹⁵⁶⁰ *Ibid.*; SCE OB at 309-310.

¹⁵⁶¹ See Assigned ALJs' E-mail Ruling Granting in Part, and Denying in Part, Southern California Edison Company's Motion to Strike Portions of Opening Testimony of The Utility Reform Network, dated July 17, 2020.

¹⁵⁶² Ex. TURN-06R at 22.

documentation demonstrating where ratepayer funded NTP&S costs have been removed from SCE's GRC request.¹⁵⁶³

Second, TURN asserts the unequitable sharing of revenues creates inappropriate conflicts of interest between shareholders and ratepayers. Because ECS utilizes resources that are funded by ratepayers, TURN questions how SCE resolves instances of competing requests from ECS and other parts of the utility. TURN argues this potential conflict of interest is even more concerning since: (1) SCE alone conducts the "but for" test that determines which costs are incremental and should therefore be charged to shareholders;¹⁵⁶⁴ (2) SCE does not have a record of the "but for" tests, which renders an audit of these tests impossible; (3) SCE does not keep a record or time log of ECS's use of utility resources.¹⁵⁶⁵

Based on these assertions, TURN recommends SCE be directed to keep a record of each of the "but for" tests that it conducts for its NTP&S offerings, as well as time logs and other appropriate records concerning NTP&S offerings' use of ratepayer funded utility resources, to be presented for review in SCE's next GRC. TURN also recommends the Commission make clear that it will consider modification of the revenue sharing mechanism in SCE's next GRC.¹⁵⁶⁶

41.1.2. SCE Response to TURN

In response, SCE asserts that ECS operates in compliance with the Commission's Affiliate Transaction Rules, and that TURN's conflict of interest

¹⁵⁶³ TURN OB at 256-260.

¹⁵⁶⁴ Under SCE's "but for" test, if SCE would not have incurred the cost "but for" the offering of any NTP&S, the cost is deemed incremental and allocated to shareholders. (Ex. SCE-18, Vol. 1 at 59.)

¹⁵⁶⁵ TURN OB at 260-263.

¹⁵⁶⁶ *Id.* at 263-264.

allegations are theoretical and not supported by actual evidence. In contrast, SCE states it has presented substantial evidence that: (1) utility needs always take the priority if there are competing demands for support; (2) SCE's established accounting procedures and mechanisms for NTP&S comply with the Affiliate Transactions Rules; (3) SCE has implemented a number of controls and processes to ensure incremental costs are properly identified and paid for by shareholders; and (4) SCE is properly accounting for ECS's temporary use of utility resources, including temporary use of SCE's IT, HR, legal, and regulatory support.¹⁵⁶⁷ Finally, SCE asserts that TURN's recommendations are improper and prejudicial to SCE.¹⁵⁶⁸ Each of these arguments are detailed below.

First, SCE states that, since its inception, ECS has relied primarily on its own dedicated staff to perform day-to-day work; this staff, which is augmented by consultants, is 100 percent funded by shareholders. While ECS does utilize available SCE employees on a temporary basis, SCE asserts the time used is minimal and does not interfere with utility operations work. When work is determined to add up to one or more FTE, labor costs are deemed incremental and charged to shareholders. SCE asserts that when ECS utilizes the temporarily available capacity of utility assets or resources, ratepayers always have priority if there are competing demands for support. If capacity is unavailable, ECS will utilize outside resources (paid for by shareholders).¹⁵⁶⁹

Second, SCE asserts it has established accounting procedures and mechanisms to identify and record the incremental costs associated with NTP&S, as required by Affiliate Transaction Rule VII.D.1. This includes: (1) annual

¹⁵⁶⁷ SCE OB at 315.

¹⁵⁶⁸ SCE RB at 164-166.

¹⁵⁶⁹ Ex. SCE-50 at 5.

training with shared service partners that support ECS to ensure employees understand their obligation to identify costs that would not be incurred “but for” ECS; (2) annual training/certification of ECS employees to ensure adherence to allocation and tracking incremental/non-incremental rules; (3) the provision of separate accounting for ECS-related costs, for each shared service partner to charge when performing work that would not be incurred “but for” ECS; and (4) as part of CPUC-mandated reporting related to ECS’s Certificate of Public Convenience and Necessity, the submission of annual work orders. Further, SCE highlights that the Commission, via the biennial Affiliate Transaction Rules audit, has the opportunity to review and identify errors with SCE’s incremental costs and operation of NTP&S.¹⁵⁷⁰

Third, SCE states that ECS’s incremental costs are charged directly to shareholders, while the Affiliate Transaction Rules permit ECS to make use of non-incremental utility resources without reimbursing the utility. Therefore, and contrary to TURN’s assertion, SCE states there is no need for shareholders to “reimburse” the utility for these non-incremental costs as part of the GRC forecast since, by definition, SCE would have incurred these costs regardless of the existence of NTP&S offerings.¹⁵⁷¹

Fourth, SCE asserts it properly accounts for ECS’s temporary use of office space as well as SCE IT, HR, legal, and regulatory resources. As office space occupied by ECS employees becomes needed for SCE electric operations, SCE states that utility employees take priority, and ECS employees are relocated to a different building. SCE indicates this is exemplified by the fact that ECS has had

¹⁵⁷⁰ *Id.* at 1-2; SCE OB at 311-312.

¹⁵⁷¹ Ex. SCE-18, Vol. 1 at 60; SCE OB at 312-313.

to move three times in the last ten years. SCE also states that ECS pays (*i.e.*, shareholders pay) for all its own IT equipment, licenses, telecommunications services, hosting, maintenance, and other costs; that ECS has its own IT project manager; and that ECS has hired IT FTEs in the past. For other IT needs, such as the help desk or other IT services, SCE asserts that ECS's small size has no impact on SCE's IT staffing plan or IT costs (ECS employees represent 0.54 percent of the total population of full-time SCE employees). Similarly, SCE asserts the small number of ECS employees, as compared to the overall SCE population, does not drive a need for additional headcount in the HR organization or otherwise impact SCE's HR costs. SCE states that ECS also pays for one full-time regulatory employee, and uses outside counsel and consulting services for most telecommunications regulatory matters, new telecommunications services contracts, and all non-disclosure agreements. While ECS does use temporary SCE legal employees on occasion, SCE indicates this limited use does not interfere with the work those employees do for utility operations.¹⁵⁷²

Lastly, SCE highlights that TURN's prepared testimony did not ask that SCE be ordered to keep records of each of the "but for" tests that it conducts and create time logs for each instance ECS utilizes temporarily available utility employees. By making this request for the first time in its opening brief, SCE asserts that TURN has provided no opportunity to directly address the requested relief in rebuttal testimony or through cross-examination of TURN's witnesses. Further, SCE asserts that creating and keeping the records and time logs requested by TURN would be impractical and administratively burdensome.¹⁵⁷³

¹⁵⁷² Ex. SCE-50 at 5-6; Ex. SCE-18, Vol. 1 at 60.

¹⁵⁷³ SCE RB at 162-167.

41.1.3. Discussion

We do not adopt any of TURN's NTP&S recommendations at this time; however, SCE is directed to include supporting testimony in its next GRC application addressing the following issues/questions:

- (1) Assuming TURN's "but for" and time log tracking recommendations were implemented for ECS, provide an estimate of the level/number of utility resources that would be impacted, an associated cost estimate, as well as the supporting calculations.
- (2) Are there alternatives to TURN's "but for" and time log tracking recommendations that would achieve similar objectives at a lower cost?
- (3) Concerning the HR services provided to ECS, provide a description of how ECS employee questions are assigned to, and addressed by, HR personnel (*i.e.*, do ECS employees have an assigned HR specialist, and if so, does that HR specialist also oversee utility employees?).
- (4) Discuss whether ECS pays for office-related expenses (including utilities), why/why not, and how SCE's current approach is consistent with the requirement that all incremental costs for NTP&S be the sole responsibility of shareholders.

As noted by SCE, TURN's recommendations that SCE keep a record of each of the "but for" tests it conducts for its NTP&S offerings, and that SCE keep time logs and other appropriate records concerning NTP&S offerings' use of ratepayer funded utility resources, were presented for the first time in TURN's opening brief. SCE was not afforded the opportunity to address in testimony or hearings the potential cost and resource impacts necessary to implement TURN's recommendations. Therefore, there is a limited record on these issues and SCE raises legitimate concerns regarding whether TURN's recommendations would be unduly costly and administratively burdensome. For example, it is unclear

how many shared SCE employees would need to be equipped with, and trained to use, the time tracking software to be able to implement TURN's recommendations, what this overall effort would cost, and how long it would take SCE to implement.

In addition, while TURN broadly states the issues surrounding ECS "apply to most, if not all of SCE's NTP&S offerings,"¹⁵⁷⁴ TURN fails to provide any actual evidence concerning the type and level of SCE resources used by other NTP&S offerings. Absent further showing, TURN's recommendations are more aptly limited to ECS.

Overall, we find that SCE has made a *prima facie* showing. Based on the record before us, SCE has provided sufficient evidentiary basis to support its claim that SCE has established accounting procedures and processes to identify and record incremental costs associated with NTP&S. We also find it reasonable to expect these processes, which include annual trainings with shared service partners to ensure employees understand their obligations to identify incremental costs that would be incurred "but for" ECS,¹⁵⁷⁵ to help limit instances where incremental costs are not properly identified. While TURN raises questions regarding the potential for inappropriate conflicts of interest and opportunities for incremental ECS costs to be borne by ratepayers, there is no evidence in this proceeding that costs have been improperly allocated. Therefore, we do not find TURN's proposed recordkeeping recommendations to be warranted at this time.

¹⁵⁷⁴ Ex. TURN-06R at 22.

¹⁵⁷⁵ Ex. SCE-50 at 2.

However, as provided above, we direct SCE to provide additional information regarding TURN's proposed recordkeeping recommendations, as well as the treatment of certain utility resources used to support ECS, as part of SCE's next GRC application. This information is intended to further inform our evaluation of both the likelihood that ECS is resulting in incremental ratepayer costs, as well as the costs and administrative impacts that would result from more rigorous reporting standards. SCE attempts to argue that it is not required to create records of its "but for" tests, and that the CPUC already conducts audits of SCE's NTP&S accounting,¹⁵⁷⁶ but these facts do not preclude the Commission from making ongoing improvements to SCE's established accounting procedures.

Lastly, we reject TURN's recommendation that the Commission consider modification of the NTP&S revenue sharing mechanism in the next GRC. As provided in the Assigned ALJs' June 17, 2020 email ruling in this proceeding,¹⁵⁷⁷ and in past Commission decisions,¹⁵⁷⁸ a rulemaking is the appropriate venue for reviewing SCE's NTP&S revenue sharing mechanism.

41.2. Added Facilities

Customers may request that SCE install facilities that are in addition to, or in substitution for, the standard facilities that SCE would normally install. These facilities are referred to as "Added Facilities."¹⁵⁷⁹ Customers who request these

¹⁵⁷⁶ SCE OB at 165.

¹⁵⁷⁷ See Assigned ALJs' E-mail Ruling Granting in Part, and Denying in Part, Southern California Edison Company's Motion to Strike Portions of Opening Testimony of the Small Business Utility Advocates, dated June 17, 2020, at 3.

¹⁵⁷⁸ See D.09-03-025 at 301-302; D.12-11-051 at 657; and D.18-09-009 at 5.

¹⁵⁷⁹ Consistent with parties' submissions, Added Facilities, as discussed with respect to EPUC's proposals, are inclusive of Interconnection Facilities. (SCE OB at 316, fn. 1837; Ex. EPUC-01-E

facilities are charged Added Facilities rates, which reflect SCE's costs of owning, operating, and maintaining the Added Facilities (*i.e.*, both capital-related and O&M-related costs). The revenue generated from Added Facilities is included in OOR and acts as an offset to the Added Facilities' costs included in the revenue requirement.

Added Facilities rates are provided under several tariff provisions depending on the facilities.¹⁵⁸⁰ SCE may either finance Added Facilities or require the customer to finance the Added Facilities. SCE currently offers the following rate options: (1) SCE-financed with replacement at additional cost; (2) SCE-financed with limited replacement for 20-year term at no additional cost; (3) SCE-financed with perpetual replacement at no additional cost; (4) Customer-financed with replacement at additional cost; (5) Customer-financed with limited replacement for a 20-year term at no additional cost; and (6) Customer-financed with perpetual replacement at no additional cost.¹⁵⁸¹ The cost of Added Facilities is recovered through a monthly charge equal to the Added Facilities investment base (*i.e.*, the non-depreciated cost basis) times the monthly Added Facilities rate applicable to the financing and replacement option.¹⁵⁸²

SCE forecasts TY OOR of \$49.299 million for SCE-Financed Added/Interconnection Facilities and \$23.439 million for Customer-Financed

at 2.) Interconnection Facilities refer to equipment installed to connect a producer's or customer's generator to SCE's system as defined in Tariff Rule 21 and various FERC tariffs. (Ex. SCE-02, Vol. 7 at 42.)

¹⁵⁸⁰ See SCE Tariff Rule 2, Section H.

¹⁵⁸¹ Ex. SCE-07, Vol. 1A2 at 101.

¹⁵⁸² Ex. SCE-18, Vol. 1 at 64.

Added/Interconnection Facilities.¹⁵⁸³ SCE uses a five-year average (2014-2018) to forecast revenues for SCE-financed facilities and last-year recorded (2018) costs to forecast revenues for Customer-financed facilities.¹⁵⁸⁴

41.2.1. EPUC Proposals

EPUC argues that SCE improperly over-collects certain Added Facilities costs from customers who elect to have SCE finance the facilities. EPUC does not oppose SCE collecting all levelized carrying costs and depreciation charges, including costs for removal, on a given Added Facility.¹⁵⁸⁵ EPUC argues, however, that SCE continues to collect capital-related costs even after all depreciation charges associated with the facility, including removal costs, have been fully recovered.

EPUC proposes the following changes to SCE's Added Facilities rates where the customer has elected an SCE-financed rate option: (1) SCE should cease charging return on investment for all pre-1988 and 1988 facilities, as well as for any subsequent years' investments where rate base becomes negative prior to the Commission issuing a decision in this proceeding; and (2) SCE should cease charging depreciation on a vintage when the accumulated depreciation equals the initial investment plus estimated removal costs.¹⁵⁸⁶ EPUC also recommends that SCE be required to monitor future accumulations of depreciation consistent with its proposals and that SCE also offer Added Facilities customers another rate option of paying off the facilities over a specified number of years.¹⁵⁸⁷

¹⁵⁸³ Ex. SCE-13, Vol. 7E2 at 2, Table I-2.

¹⁵⁸⁴ Ex. SCE-02, Vol. 7 at 45; Ex. SCE-02, Vol. 7E at 43-44.

¹⁵⁸⁵ EPUC OB at 1.

¹⁵⁸⁶ Ex. EPUC-01-E at 3.

¹⁵⁸⁷ *Id.* at 3-4.

SCE argues that EPUC's proposals are not appropriately considered in a utility-specific GRC proceeding because they seek to revise SCE's Added Facilities tariff, which would effectively change the law applicable to all utilities and all utility customers within the context of SCE's GRC.¹⁵⁸⁸ In addressing the merits of EPUC's proposals, SCE argues that EPUC's proposals should be rejected, as they are inconsistent with cost-of-service ratemaking and overlook key cost components accounted for in SCE's Added Facilities rates.¹⁵⁸⁹

We find that changes to SCE's Added Facilities tariff are appropriate for consideration in this GRC. EPUC's proposals only impact SCE's tariff, not the tariffs of other electric utilities. As discussed further below, SCE itself proposes modifications to its Added Facilities rate options. In considering the merits of EPUC's proposals, we do not find that changes to SCE's methodology for calculating Added Facilities rates are warranted.

We find that SCE's methodology for calculating Added Facilities rates is consistent with cost-of-service ratemaking. SCE's longstanding methodology for calculating Added Facilities rates is based on portfolio-derived levelized rates.¹⁵⁹⁰ SCE models the revenue requirement stream for a portfolio of its transmission and distribution facilities over their average service lives. SCE then converts this declining revenue stream into a levelized rate, which produces a levelized revenue stream equal to the net present value. As described in the Depreciation and Decommissioning Section (Section 43), this methodology is consistent with how SCE depreciates all of its gross plant accounts (*i.e.*, broad group, average life procedure). Under this methodology, an asset will be included in the gross plant

¹⁵⁸⁸ SCE OB at 319-320.

¹⁵⁸⁹ *Id.* at 317-319.

¹⁵⁹⁰ Ex. SCE-18, Vol. 1 at 64.

account (to which a depreciation rate is applied) as long as the asset is in service. Some assets in the group plant account will fail prior to the average service life and some will survive beyond the average service life. SCE's portfolio-derived levelized rate ensures that SCE can recover the return of its portfolio of Added Facilities investments.

EPUC presents various schedules listing gross and net Added Facility investments and current annual charges for SCE-financed Added Facilities.¹⁵⁹¹ EPUC contends that these schedules demonstrate that SCE improperly over-collects capital-related costs for certain investments where the accumulated depreciation exceeds the initial investment.¹⁵⁹²

We do not find EPUC's arguments based on these schedules to be persuasive. As an initial matter, SCE's depreciation accruals include costs of removal.¹⁵⁹³ Therefore, the fact that the accumulated depreciation may exceed the investment base does not demonstrate that SCE has over-collected costs.

In addition, these schedules reflect incomplete data. EPUC obtained the figures in these schedules from data request responses by SCE. SCE explains that the figures are estimates and do not reflect actual depreciation accruals because SCE does not individually account for facilities.¹⁵⁹⁴ The figures also do not include any assets that were retired prior to December 31, 2018, which means that assets for which SCE has under-recovered are not represented.¹⁵⁹⁵ SCE states that the actual depreciation accruals would differ from the figures shown

¹⁵⁹¹ Schedules MEB 1-3 attached to Ex. EPUC-01-E.

¹⁵⁹² Ex. EPUC-01-E at 6-9.

¹⁵⁹³ Ex. SCE-18, Vol. 1 at 66.

¹⁵⁹⁴ *Ibid.*

¹⁵⁹⁵ Ex. SCE-53 at 3.

on the schedules based on: (1) the actual mix of assets, both currently installed and already retired, that comprise the Added Facilities portfolio, and (2) the underlying assumptions for depreciation and cost of removal rates that vary based on the Commission's decisions in each of SCE's GRCs over that period.¹⁵⁹⁶

The revenues generated from Added Facilities rates are included in OOR and offset costs included in the revenue requirement.¹⁵⁹⁷ Because SCE's Added Facilities rates are based on portfolio-derived levelized rates, ceasing cost recovery after an individual asset rather than the portfolio has reached full cost recovery, as proposed by EPUC, would result in shortfalls that would need to be subsidized by other customers.¹⁵⁹⁸

Furthermore, since SCE does not separately track accumulated depreciation for each Added Facility asset, it is likely infeasible to determine the specific accruals for each asset, which would be required to implement EPUC's proposals. We also do not find cause to require SCE to deviate from traditional group accounting practices to undertake the burdensome task of separately tracking such depreciation accruals in the future or developing individualized rate options for each of its approximately 900 active SCE-financed Added Facility customers.¹⁵⁹⁹ As acknowledged by EPUC, Added Facility customers have the option to choose the customer-financed option if the SCE-financed options are not agreeable to them.¹⁶⁰⁰ EPUC also agrees that EPUC members "have the wherewithal to analyze and weigh the financial impact of choosing the SCE-

¹⁵⁹⁶ Ex. SCE-18, Vol. 1 at 66.

¹⁵⁹⁷ *Id.* at 62.

¹⁵⁹⁸ Ex. SCE-53 at 4-5.

¹⁵⁹⁹ *Id.* at 5.

¹⁶⁰⁰ EPUC RB at 3.

financed option over the customer-financed option with full knowledge of SCE's Added Facilities rates."¹⁶⁰¹ Although EPUC cites to the added convenience of the SCE-financed option, there is no evidence that there are barriers that would restrict these customers from obtaining their own competitively priced financing.

Because we do not find that changes to SCE's methodology for calculating Added Facilities rates are warranted, we find reasonable and approve SCE's TY OOR forecast of \$49.299 million for SCE-Financed Added/Interconnection Facilities and uncontested TY OOR forecast of \$23.439 million for Customer-Financed Added/Interconnection Facilities.

41.2.2. SCE Proposals

In D.96-01-011, the decision that approved SCE's 1995 GRC, the Commission approved SCE's proposal to create a 20-year replacement rate option for Added Facilities. The contractual agreement between SCE and Added Facilities customers who choose the 20-year replacement coverage option terminates at the end of the 20-year term and customers must enter into a new contractual agreement to continue to receive Added Facilities service.

SCE proposes that once the 20-year coverage term expires, the customer can: (1) terminate its Added Facilities service and SCE will provide the customer with the otherwise applicable standard service without assessing any costs to remove the Added Facilities equipment or terminate the contract; (2) extend its Added Facilities service with no replacement coverage; or (3) extend its Added Facilities service with replacement coverage in perpetuity with the customer also paying a "make-whole payment" to account for the difference between what SCE collected from the customer based on the 20-year replacement rate versus

¹⁶⁰¹ *Ibid.*

replacement coverage in perpetuity.¹⁶⁰² SCE requests an additional 90 days after the issuance of a decision in this GRC to allow SCE and affected Added Facilities customers to negotiate the new Added Facilities contracts. We find reasonable and approve SCE's uncontested proposals for addressing terminated or terminating contracts with 20-year terms.

42. Rate Base

Rate base is the net investment value on which SCE's return is determined. Rate base represents the depreciated value of assets in service. The major components of rate base include: net plant-in-service (gross capital minus accumulated book depreciation), working capital, and accumulated deferred taxes. SCE's rate base forecast for 2021 is \$35.907 billion.¹⁶⁰³ Issues impacting rate base, such as SCE's forecasted capital expenditures and forecasted depreciation expense, are addressed in other sections of this decision. Additional contested issues concerning rate base components are discussed below.

42.1. Aged Poles

In 2013, SCE initiated an aged pole program that replaced poles over a certain age regardless of their condition. In the 2015 GRC, the Commission found that SCE failed to demonstrate that the aged pole replacements were prudent at the level requested and disallowed a substantial portion of the costs associated with the program, permitting SCE to add to rate base the costs of the pole replacements for 2013, a portion of those for 2014, and none for 2015.¹⁶⁰⁴ In the 2018 GRC, the Commission continued to disallow recovery for the 2014 and

¹⁶⁰² Ex. SCE-07, Vol. 1A2 at 103-104.

¹⁶⁰³ Ex. SCE-07, Vol. 2A at 2, Table I-1.

¹⁶⁰⁴ D.15-11-021 at 113-114.

2015 pole replacements given the lack of evidence supporting the prudence of the expenditures.¹⁶⁰⁵

SCE argues that it is reasonable to begin cost recovery for the disallowed poles in 2021 because the costs customers will begin paying in 2021 are less than what they would have paid for replacement poles had SCE never undertaken the aged pole program. According to SCE, the present value revenue requirement (PVRR)¹⁶⁰⁶ of SCE's proposal is \$38 million, whereas the PVRR of the replacement poles absent the aged pole program is \$60.3 million. SCE argues that its proposal is reasonable because the goal is to make customers indifferent to SCE's actions, not to put them in a better position. SCE's proposal would add approximately \$14.6 million to the TY revenue requirement.¹⁶⁰⁷

TURN argues that the aged pole disallowance should remain in effect through this GRC cycle. TURN argues that SCE has failed to establish the prudence of its investment decision, which the Commission's prior decisions made clear was a precondition to rate recovery.¹⁶⁰⁸ TURN notes that SCE's aged pole remaining life analysis calculated a 10-year remaining life for the poles and other equipment replaced in 2014-2015. Although TURN argues that a 12-year remaining life is more reasonable, TURN states that even if the Commission were to accept SCE's estimated remaining life, the poles replaced in 2014 and 2015 would otherwise have been replaced in 2024 and 2025, on average.¹⁶⁰⁹

¹⁶⁰⁵ D.19-05-020 at 329.

¹⁶⁰⁶ "A PVRR analysis takes the revenue requirement of a stream of an investment and re-states it at a single point in time, allowing one to compare the revenue requirement of the investment at different points in time on equivalent terms." (Ex. SCE-18, Vol. 2 at 5.)

¹⁶⁰⁷ Ex. TURN-11 at 2.

¹⁶⁰⁸ TURN OB at 266-268 citing D.15-11-021 and D.19-05-020.

¹⁶⁰⁹ TURN OB at 269.

In both the 2015 and 2018 GRCs, the Commission made clear that the question of whether the Commission would allow recovery in rates for the expenditures to purchase and install the poles “turns on the prudence of the investment decision.”¹⁶¹⁰ In the 2018 GRC, the Commission recognized “that at some point in time it would become prudent to replace these aged poles” and did not preclude SCE from establishing the prudence of replacing the poles by a certain date or dates in its next GRC.¹⁶¹¹

We again affirm that the question of recovery turns on the prudence of the investment decision. As in the 2015 and 2018 GRCs, SCE has not presented evidence that supports a finding that it would have been prudent to replace the poles during this GRC cycle. The evidence supports a finding that the poles would have continued to be useful at least through 2024-2025, on average, or longer.¹⁶¹²

SCE’s PVRR analysis does not demonstrate the prudence of the investment or the reasonableness of including the poles in rates for this GRC cycle. SCE does not cite to any precedent that supports using a PVRR showing or customer indifference standard to determine the duration of a disallowance.¹⁶¹³ Rather, as explained above, the Commission has consistently held that the duration of the disallowance depends on the prudence of the investment.

SCE argues that the Commission has relied on a PVRR analysis in an analogous context for the pole loading program in the 2018 GRC to evaluate

¹⁶¹⁰ D.15-11-021 at 112; D.19-05-020 at 328-329.

¹⁶¹¹ D.19-05-020 at 329.

¹⁶¹² Ex. TURN-11 at 5-9.

¹⁶¹³ In any event, contrary to SCE’s claims that customers would be indifferent, customers would pay more during this GRC cycle under SCE’s proposal than if the original poles had retired naturally.

“potential disallowance based on various timing scenarios and other factors.”¹⁶¹⁴ However, the purpose of the PVRR calculations with regard to the pole loading program was not to determine prudence or the appropriate duration of the disallowance. In fact, the Commission found that the premature replacement of poles that continued to be useful was imprudent and used the anticipated lifespan of the poles to determine the appropriate duration of the disallowance.¹⁶¹⁵ The Commission then used the PVRR calculations to determine the corresponding disallowance figure for a single-GRC cycle based on TURN and SCE’s agreement that the disallowance should be amortized over the 2018 GRC cycle rather than for the anticipated lifespan of the poles.

Because SCE has failed to make the required showing, we continue to disallow recovery for the 2014 and 2015 pole replacements through this GRC cycle. SCE argues that if the Commission continues the disallowance, it is likely that SCE would write-off its investment completely, which would result in the immediate unwinding of \$38 million in associated tax benefits previously realized by ratepayers.¹⁶¹⁶ The Commission will review the impacts of any such write-off and tax benefit unwinding proposal in its review of the recorded operation of the Tax Accounting Memorandum Account.

42.2. Working Capital

For ratemaking purposes, working capital is the average additional expenditures required of investors on a continuing basis beyond the capital expenditures in plant-in-service. For SCE, these components include: materials and supplies inventory, Mountainview emissions credits inventory, working

¹⁶¹⁴ Ex. SCE-18, Vol. 2 at 8 quoting D.19-05-020 at 337.

¹⁶¹⁵ D.19-05-020 at 340.

¹⁶¹⁶ SCE OB at 326.

cash, and working capital adjustments.¹⁶¹⁷ Working cash is the capital supplied by investors to meet day-to-day utility operational requirements and consists of lead-lag and operational cash requirements. Working capital adjustments are offsets to rate base and include customer advances, customer deposits, and unfunded pension reserve.

42.2.1. Lead-Lag Study

SCE's lead-lag study determines the funds required from investors to cover the timing difference between when operating expenses are paid and when revenues are received. The lead-lag working cash requirement is calculated by multiplying the net lag days (difference between the revenue and expense lags) by average daily expense. SCE forecasts a lead-lag working cash requirement of \$844.24 million for 2021 based on an average revenue lag of 45.1 days, average expense lag of 20.0 days, and forecasted daily expense of \$33.66 million.¹⁶¹⁸

Cal Advocates recommends modifications to the working cash estimates for: (1) fuel and purchased power; (2) wildfire insurance premiums; and (3) taxes based on income. TURN recommends modifications to the working cash estimates for: (1) goods and services; (2) depreciation expense; and (3) taxes based on income.

42.2.1.1. Fuel and Purchased Power Lag Days

Fuel costs include natural gas, diesel, propane, and nuclear fuel used by SCE's generating stations. Purchased power costs include: (1) qualifying facilities (QF) and (2) non-QF bilateral and firm agreements and other energy related costs. SCE's fuel and purchased power lead-lag study is based on the

¹⁶¹⁷ Ex. SCE-07, Vol. 2A at 23.

¹⁶¹⁸ *Id.* at 32, Table III-15. The working cash portion of the lead-lag study changes based on the forecast O&M and capital expenditures.

dollar-weighted average payment lag days for each transaction type in 2018 and applied to the 2021 TY forecast.

Cal Advocates recommends an increase in lag days for fuel and purchased power using a “four-year simple moving average (SMA) to forecast the lag days for each fuel and purchased power line item.”¹⁶¹⁹ Cal Advocates argues that SCE’s method does not account for trends in lag day data nor does it buffer the lag day estimate for line items with high variability.

Given the variability in recorded lag days,¹⁶²⁰ we find it reasonable to base the forecast on four years of recorded data rather than relying solely on 2018 recorded data. However, we find merit to SCE’s arguments that Cal Advocates’ use of a SMA ignores the dollar impact in each year and distorts the weighting of the actual transactions. Therefore, we find it reasonable to adopt SCE’s alternative proposal to use a 4-year average based on dollar-weighted payment amounts¹⁶²¹ rather than Cal Advocates’ proposed 4-year SMA.

SCE accepts Cal Advocates’ recommendation to update SCE’s fuel and purchased power forecast from Spring 2019 to Fall 2019.¹⁶²² We find this recommendation to be reasonable and adopt it.

42.2.1.2. Wildfire Insurance Premiums

Wildfire Insurance Premiums are the amounts paid to insurance providers for wildfire insurance coverage. The majority of payments are paid on an annual

¹⁶¹⁹ Ex. PAO-15 at 10.

¹⁶²⁰ See Ex. PAO-15-WP-C at 2-4.

¹⁶²¹ Ex. SCE-18, Vol.2C at 17, fn. 38.

¹⁶²² Ex. SCE-18, Vol. 2 at 16.

basis and others on a quarterly basis.¹⁶²³ The expense lag is calculated based on the midpoint of the insurance coverage period and the payment date.¹⁶²⁴

SCE recommends -186.9 lag days for Wildfire Insurance Premiums based on using all available recorded data from 2017-2019 to determine the dollar-weighted average payment lag days.¹⁶²⁵

Cal Advocates recommends -171.7 lag days for Wildfire Insurance Premiums by taking a simple average of the weighted average lag day results from each year between 2017-2019.¹⁶²⁶ Over half of SCE's recorded payments are from 2019. Cal Advocates argues that SCE's lag day calculation places too much weight on 2019 payments and recommends a more conservative estimate given the lack of data spanning more years.¹⁶²⁷

We find merit to SCE's argument that Cal Advocates' methodology does not take into account the weighting of the actual transaction and underweights the more recently experienced data.¹⁶²⁸ We find SCE's methodology, which is based on all available recorded data and gives appropriate weight to each transaction, to be reasonable. Therefore, we adopt SCE's proposed -186.9 lag days.

42.2.1.3. Goods and Services

SCE's lead-lag proposal for Goods and Services is a composite total of 37.3 lag days based on the dollar-weighted average payment lag days for Purchase

¹⁶²³ Ex. SCE-07, Vol. 2A at 39.

¹⁶²⁴ *Ibid.*

¹⁶²⁵ Ex. SCE-54 at 232.

¹⁶²⁶ Ex. PAO-15 at 13.

¹⁶²⁷ *Ibid.*

¹⁶²⁸ SCE OB at 329.

Order (PO) (40.2 days) and Non-PO transactions (11.7 days).¹⁶²⁹ SCE's calculation is based on analyzing \$4 billion of recorded payments from 2018.¹⁶³⁰

TURN argues, based on external benchmarks and SCE's own best past performance, SCE should be targeting at least 45 lag days for its Goods and Services PO Payments, which would reduce SCE's working cash requirement by \$15.361 million.¹⁶³¹ TURN notes that PWC Consulting's most recent Working Capital Report indicates median lag days of 59 days for utilities globally and 55 days for North American corporations generally.¹⁶³² TURN also notes that 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, and that SCE's standard PO payment term is currently 60 days.¹⁶³³

Despite SCE's recent recorded data, we do not find SCE's proposed 40.2 lag days for PO orders to be reasonable. SCE explains that the declining trend in lag days (making payments faster) is due to: (1) accelerated payments to small business suppliers, including Diverse Business Enterprises (DBEs) to help with their cash flow; (2) savings from vendor discount programs; and (3) faster processing of payments due to suppliers switching from checks to electronic payments.¹⁶³⁴ We do not find that these explanations provide adequate justification for SCE's proposal.

¹⁶²⁹ Ex. SCE-18, Vol. 2 at 20, Table III-6.

¹⁶³⁰ *Id.* at 20.

¹⁶³¹ Ex. SCE-54 at 233.

¹⁶³² TURN OB at 272-273.

¹⁶³³ *Id.* at 273.

¹⁶³⁴ SCE OB at 331-332.

SCE fails to explain why expedited payments to DBEs would justify lag days 7.7 to 11.7 days shorter than what SCE has been able to achieve in the past when payments to DBEs made up 47 percent of SCE's spending in 2018 and, on average, were only 3 days faster than payments to Non-DBEs.¹⁶³⁵

Moreover, SCE's recorded PO lag days and vendor discounts indicate that the level of vendor discounts is not necessarily negatively impacted by targeting higher PO payment lag days.¹⁶³⁶ The forecasted vendor discount level of \$11.2 million for 2021 is similar to vendor discount levels achieved in the past at PO lag days exceeding the 45 days proposed by TURN.

Finally, we are not persuaded by SCE's argument that suppliers switching from check to electronic payment justifies the shorter lag days proposed by SCE. We agree with TURN that the timing of these payments is within SCE's control. SCE fails to explain why it could not account for the faster processing time when determining the timing of these payments, particularly for payments that are not to DBE businesses or subject to the vendor discount program.

We do not find SCE's proposal to be consistent with best cash management practices. SCE should work to effectively manage working cash to minimize costs to ratepayers by fully utilizing vendor credit where possible. Therefore, we find reasonable and adopt TURN's proposal of 45 days for PO payments. SCE's proposal of 11.7 days for non-PO payments is uncontested and is approved.

42.2.1.4. Depreciation Expense

Depreciation expense is included in SCE's lead-lag study to compensate investors for the lag between when the expenses are accrued and when the

¹⁶³⁵ Ex. SCE-18, Vol. 2 at 21.

¹⁶³⁶ TURN OB at 275.

revenues are collected.¹⁶³⁷ SCE proposes a depreciation expense lag of zero days because depreciation expense accrual and its impact on rate base occur simultaneously.¹⁶³⁸ SCE argues that its proposal is also consistent with Standard Practice (SP) U-16 and Commission precedent.¹⁶³⁹

TURN recommends a depreciation expense lag of 15.2 days. TURN argues that because depreciation is accrued monthly as part of the accounting cycle, the midpoint is 15.2 days.¹⁶⁴⁰

SCE reduces rate base at the same time that depreciation expense is accrued at the midpoint of the service period.¹⁶⁴¹ It is undisputed that there is a 45.1 day revenue lag between when the depreciation expense is recorded (and rate base reduced) and when revenue is received from the customer.¹⁶⁴² TURN's proposal would result in a 15.2-day gap during which rate base has been lowered but the corresponding depreciation expense has not yet been received from the customer.¹⁶⁴³ We do not find such an approach to be consistent with SP U-16 or past Commission precedent¹⁶⁴⁴ nor do we find justification to deviate from SP U-16 or past precedent. We find it appropriate to continue the longstanding practice of compensating for this lag such that rate base is kept whole until

¹⁶³⁷ Ex. SCE-07, Vol 2A at 37.

¹⁶³⁸ Ex. SCE-18, Vol. 2 at 24.

¹⁶³⁹ *Ibid.* SP U-16 at paragraph 40 states: [s]ince book depreciation is occurring uniformly day by day and accumulated depreciation is deducted from the rate base, the practice is to include depreciation provisions at zero lag days." (Ex. SCE-18, Vol. 2, Appendix B at B-25.)

¹⁶⁴⁰ Ex. TURN-03-E at 36.

¹⁶⁴¹ Ex. SCE-18, Vol. 2 at 26.

¹⁶⁴² *Id.* at 25.

¹⁶⁴³ *Id.* at 25, Figure III-4.

¹⁶⁴⁴ D.19-05-020 at 310.

payment is received from the customer, and therefore, adopt SCE's proposed 0-day lag for depreciation expense.

42.2.1.5. Synchronized Interest Adjustments

TURN initially proposed that the Commission include interest expense on long-term debt in the calculation of lead-lag working cash. TURN subsequently withdrew this proposal after reviewing SCE's rebuttal testimony.¹⁶⁴⁵ Therefore, no further consideration of this proposal is necessary.

42.2.1.6. Taxes Based on Income

SCE's expense lag for income taxes represents the period from when the current tax expenses are accrued to the time they are due by statutory law.¹⁶⁴⁶ Under both federal and state law, a corporation is required to file estimated taxes in four installments throughout the year with any balance due upon the original due date of the tax return.¹⁶⁴⁷ SCE forecasts a federal income tax lag of 61.8 days and a state income tax lag of 55.4 days based on accrual midpoint dates of July 2, 2009 and July 2, 2016, respectively.¹⁶⁴⁸ Due to net operating loss and other tax credit carryovers, SCE has not had federal taxes due since 2009 and California taxes due since 2016.¹⁶⁴⁹ SCE, therefore, uses its five-year (2005-2009) tax payment history to forecast the federal income tax lag and its five-year (2011-2016) tax payment history to forecast the state income tax lag.¹⁶⁵⁰

¹⁶⁴⁵ TURN OB at 279.

¹⁶⁴⁶ Ex. SCE-07, Vol. 2A at 37.

¹⁶⁴⁷ *Id.* at 37-38.

¹⁶⁴⁸ SCE originally proposed accrual midpoint dates of July 13, 2009 and July 9, 2016 but agreed to revise the dates based on Cal Advocates' recommendation. (Ex. SCE-18, Vol. 2 at 32.)

¹⁶⁴⁹ Ex. SCE-07, Vol. 2A at 38.

¹⁶⁵⁰ *Ibid.*

TURN recommends 365 lag days for federal and state income taxes because SCE has not been a net taxpayer since before the 2018 GRC cycle and is unlikely to have any actual tax burden during the 2021 rate case cycle.¹⁶⁵¹ TURN argues that a tax burden is unlikely given: (1) the potential for net operating losses associated with wildfires, and (2) the liberalization of carry forward and carry back rules in the tax provisions of the CARES Act passed in March 2020.¹⁶⁵² Alternatively, TURN recommends 365 lag days for federal taxes and 190.2 lag days for state taxes based on the average lag days for SCE's taxes due and paid from 2011-2018.¹⁶⁵³

SCE argues that in D.84-05-036 ("OII 24"), the Commission made it clear that the tax impacts associated with disallowed expenses and events outside the utility operations should not be considered when setting rates and that the separate return method is the more reasonable basis for calculating test-year income tax expenses.¹⁶⁵⁴ SCE argues that TURN's arguments that SCE will not be a taxpayer during this rate cycle are impermissibly based on events outside this rate case.

The purpose of calculating income tax lag days is to make appropriate adjustments to the working cash requirement, which is intended to ensure that the utility has sufficient cash for day-to-day operational requirements. For SCE, going back to at least the 2012 GRC, the Commission has used the weighted

¹⁶⁵¹ TURN OB at 279.

¹⁶⁵² Ex. TURN-03-E at 41.

¹⁶⁵³ *Id.* at 42.

¹⁶⁵⁴ SCE OB at 339-340.

average of SCE's historical payment data to determine the income tax lag days that would be most representative for each respective test year.¹⁶⁵⁵

We do not find SCE's forecasted lag days for state and federal income taxes to be reasonable because SCE fails to demonstrate that they are likely to be representative of the lag days for the test year. SCE fails to justify going back to tax payment history for 2005-2009 and 2011-2016 to forecast lag days for 2021. We cannot ignore the reality that SCE last paid federal income taxes in 2009 and state income taxes in 2016. Moreover, SCE does not attempt to deny that its tax situation is unlikely to change in the upcoming GRC cycle. SCE generally agrees that it has incurred significant deductible tax costs over the past 10 years and that the deductibility of potential wildfire obligations could limit federal or state tax liabilities for the next few years.¹⁶⁵⁶

Given that SCE has not paid federal income taxes for several GRC cycles and state income taxes since before the last GRC cycle and given the lack of evidence that SCE's tax situation is likely to change for this GRC cycle, we find TURN's proposal to use 365 lag days for both state and federal taxes to be reasonable for purposes of calculating the appropriate expense lag adjustment to working cash.

We note that this outcome is not incompatible with OII 24. In OII 24, the Commission stated:

In this and other instances in this decision we address general principles and adopt methods that correspond with our policy judgments. We do not intend to foreclose consideration of extraordinary solutions to extraordinary problems and will

¹⁶⁵⁵ See D.19-05-020 at 307-308.

¹⁶⁵⁶ SCE OB at 339.

consider alternatives in appropriate circumstances. The Air California-Westgate situation might have been such a case.¹⁶⁵⁷

OII 24 describes the Air California-Westgate situation as an example where a consolidated group was in a permanent loss position.¹⁶⁵⁸ Therefore, OII 24 does not foreclose the possibility that under extraordinary circumstances, it would be appropriate for the Commission to consider tax impacts associated with events outside the rate case in forecasting income tax expenses for ratesetting purposes. Circumstances under which a utility has not paid federal taxes for over a decade and state taxes for over a GRC cycle constitute such extraordinary circumstances that would warrant an alternative method.

42.2.2. Customer Deposits

Customer Deposits (CDs) are funds collected from customers as a form of security deposit in the event of non-payment. In every GRC since 2003, the Commission has required SCE to offset rate base by the amount of its CDs as an adjustment for working cash.¹⁶⁵⁹ Beginning with SCE's 2012 GRC, the Commission has granted SCE permission to use up to 10 percent of its CDs to promote the Company's use of minority and community banks.¹⁶⁶⁰ The CDs housed in SCE's minority and community bank program are not included as an offset to rate base.

SCE requests that the Commission allow SCE to no longer reduce the working cash requirement due to interest-bearing CDs and consequently no

¹⁶⁵⁷ OII 24 at 26.

¹⁶⁵⁸ *Id.* at 19-20.

¹⁶⁵⁹ D.04-07-022 (SCE 2003 GRC) at 249-255; D.06-05-016 (SCE 2006 GRC) at 279-282; D.09-03-025 (SCE 2009 GRC) at 278-290; D.12-11-051 (SCE 2012 GRC) at 627-629; D.15-11-021 (SCE 2015 GRC) at 470-473; D.19-05-020 (SCE 2018 GRC) at 310-311.

¹⁶⁶⁰ D.12-11-051 at 628-630 and 877, COL 534.

longer reduce rate base by 90 percent of the amount of the CD balance. SCE argues that its request is consistent with SP U-16, which excludes interest-bearing accounts from working cash, and the treatment adopted for SDG&E and SoCalGas in D.19-09-051.¹⁶⁶¹

Consistent with the treatment adopted in recent PG&E GRCs, Cal Advocates recommends that SCE compensate CDs at the long-term cost of debt, with a resulting reduction to the GRC revenue requirement. Specifically, Cal Advocates recommends taking the difference of the utility's authorized return on long-term debt and the 3-month non-financial commercial paper rate and multiplying that amount by SCE's forecast of CDs in 2021. Cal Advocates' recommendation results in a revenue requirement reduction of \$8.46 million.¹⁶⁶²

TURN argues that in every GRC since 2003, the Commission has required SCE to use CDs to offset rate base on the grounds that the deposit balances should be treated like a source of permanent working capital. TURN recommends that the Commission continue this practice and continue to authorize SCE to use up to 10 percent of its CDs to promote its minority and community bank program.¹⁶⁶³

SCE fails to present a convincing argument as to why the Commission should discontinue the longstanding policy of treating CDs as a source of permanent working capital for SCE. In every GRC since the 2003 GRC, the Commission has considered and rejected arguments by SCE that CDs should not be an offset to rate base because CDs are not like accruals and other working cash

¹⁶⁶¹ SCE OB at 342-344.

¹⁶⁶² Cal Advocates OB at 273-274.

¹⁶⁶³ TURN OB at 282.

adjustments, and because such treatment is not consistent with SP U-16 or treatment adopted for other utilities.¹⁶⁶⁴

In the 2003 GRC decision in which the Commission instituted this policy, the Commission explained that the Commission has adopted deviations from SP U-16 in utility-specific rate cases and that deviation from SP U-16 was warranted with respect to SCE's CDs.¹⁶⁶⁵ The Commission found that: "Circumstances have changed since U-16 was developed, and it is not reasonable to assume that SCE's customer deposit amounts are relatively small and interest rates are relatively large compared to the rate of return on rate base."¹⁶⁶⁶

In conjunction with requiring SCE to use CDs as a rate base offset, the Commission has also authorized SCE to recover related interest costs through an O&M adjustment. SP U-16 provides that noninterest-bearing CDs should be deducted from the operational cash requirement. The Commission reasoned that providing for recovery of the related interest costs made the utility whole and made SCE's CDs comparable to noninterest-bearing CDs for ratemaking purposes.¹⁶⁶⁷

SCE presents no new arguments that would warrant a change to the longstanding policy, and therefore, we find it reasonable to continue the policy of requiring SCE to use CDs to offset rate base. The record supports that CDs have continued to act as a substantial source of permanent low-cost working capital for SCE. SCE states that it does not segregate the cash associated with CDs from all other sources of available operating funds or working cash other than the

¹⁶⁶⁴ See fn. 1668, *supra*.

¹⁶⁶⁵ D.04-07-022 at 252-254 and 344, FOFs 210 and 211.

¹⁶⁶⁶ *Id.* at 344, Finding of Fact (FOF) 210.

¹⁶⁶⁷ D.09-03-025 at 288.

10 percent of CDs in its minority and community bank program.¹⁶⁶⁸ Moreover, SCE's CDs have remained at a high, stable level with the 13-month rolling average increasing from \$195 million in 2012 to \$290 million at the end of 2018.¹⁶⁶⁹ The interest SCE has paid on CDs has ranged from 0.19 percent-1.84 percent annually over the 2011-2018 period.¹⁶⁷⁰

SCE anticipates a decline in CDs during this GRC cycle because, pursuant to the Commission's recent decision in D.20-06-003, SCE can no longer request deposits from residential customers seeking new or reconnected service.¹⁶⁷¹ Taking into account the anticipated decline in CD balances due to D.20-06-003, SCE still forecasts balances ranging from \$261.41 million in 2021 to \$221.89 million in 2023.¹⁶⁷²

Recognizing that balances will likely decline, we find it reasonable to adopt the lowest average forecast value of \$221.89 million for the TY forecast. We also continue to authorize SCE to use up to 10 percent of its CDs to promote its minority and community bank program. Therefore, we direct \$221.89 million, less 10 percent devoted to the minority and community bank program, to be used as a rate base offset. Consistent with past treatment, we also authorize an offsetting interest expense for the portion of CDs that are applied as a reduction to rate base at the three month- non-financial commercial paper interest rate.¹⁶⁷³

¹⁶⁶⁸ Ex. TURN-67, Response to DR TURN-SCE 114, Question 1.a.

¹⁶⁶⁹ *Id.* at Response to DR TURN-SCE-114, Question 1.c.

¹⁶⁷⁰ Ex. TURN-03-E at 47.

¹⁶⁷¹ SCE OB at 346-347 citing D.20-06-003 at 145, OP 9.

¹⁶⁷² Ex. TURN-67, Response to DR TURN-SCE 114, Question 1.c.

¹⁶⁷³ We find Cal Advocates' forecast of 1.51 percent based on the April 2020 interest rate to be reasonable. (Ex. PAO-15 at 15.)

42.3. Other Working Cash Issues

42.3.1. Palo Verde Material and Supplies

SCE initially proposed basing the forecast Materials and Supplies (M&S) inventory for Palo Verde on an average of 2016-2018 recorded data subject to non-labor escalation. TURN proposes to instead base the forecast on the Palo Verde budget. The budget inventory indicates a 4.65 percent reduction between 2018 and 2021. TURN proposes to apply the same reduction to SCE's recorded 2018 M&S inventory resulting in a forecast of \$32.296 million.¹⁶⁷⁴

SCE accepts TURN's recommendation to base the forecast on budget data. However, SCE states that the total reduction should be lowered by \$433,000 to account for the sales tax and unpaid inventory adjustments, which are applied to all M&S inventory.¹⁶⁷⁵ TURN accepts this additional adjustment.¹⁶⁷⁶

We find reasonable and adopt the M&S inventory forecast of \$31.863 million based on the budget data with adjustments for sales tax and unpaid inventory.

42.3.2. Long-Term Incentives

SCE's proposed customer funding of Long-Term Incentives (LTI) has a working cash impact that reduces rate base by \$7.9 million due to the timing difference between the receipt of cash from customers and the funding of the LTI.¹⁶⁷⁷ Since we deny customer funding of LTI, this results in the removal of the corresponding rate base reduction in working cash.

¹⁶⁷⁴ TURN OB at 286-287.

¹⁶⁷⁵ SCE OB at 347.

¹⁶⁷⁶ TURN OB at 287.

¹⁶⁷⁷ Ex. SCE-18, Vol. 2 at 31.

43. Depreciation and Decommissioning

The purpose of depreciation is to recover the original cost of fixed capital assets less the estimated net salvage over the useful life of the property.¹⁶⁷⁸

Depreciation accounting is intended to systematically and rationally allocate the service value over the life of the asset, in a manner that ensures that customers pay for the portion of the asset's cost from which they receive benefit.

Depreciation expense is a legitimate cost of service.

The depreciation system SCE uses is the straight-line remaining life method based on the Commission's SP U-4. This method is "designed to ratably recover the cost of plant, less net salvage and less depreciation reserve, over the remaining life of plant."¹⁶⁷⁹ The straight-line remaining life method can be represented by the following formula:¹⁶⁸⁰

$$\text{Annual Depreciation Accrual} = \frac{\text{Plant Balance} - \text{Gross Salvage} + \text{Cost of Removal} - \text{Depreciation Reserve}}{\text{Remaining Life of Asset(s)}}$$

SCE also uses the broad group, average life procedure to determine depreciation, which groups certain categories of plant and depreciates them as a single group.¹⁶⁸¹

SCE's currently authorized depreciation expense based on year end (YE) 2018 CPUC plant balances is \$1.604 billion.¹⁶⁸² Overall, SCE proposes to increase

¹⁶⁷⁸ Standard Practice (SP) U-4 (Determination of Straight-Line Remaining Life Depreciation Accruals), ch. 1 at 4. All citations to SP U-4 in this decision are to the version available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M042/K177/42177433.PDF>, last accessed June 30, 2021.

¹⁶⁷⁹ *Id.*, ch. 2 at 5.

¹⁶⁸⁰ *Id.*, ch. 4 at 11.

¹⁶⁸¹ Ex. SCE-07, Vol. 3 at 10.

¹⁶⁸² Ex. SCE-18, Vol. 3, at 1, Table I-1.

depreciation expense by \$227 million based on 2018 plant balances, which equates to a total proposed depreciation expense of \$1.830 billion.¹⁶⁸³ SCE's requested changes are summarized in the following table:¹⁶⁸⁴

Item	Proposed Change (in \$ millions)
T&D Net Salvage	199
T&D Life	(15)
Small Hydro Decommissioning	30
Other Generation (Decommissioning Escalation, Perris, Palo Verde, Fuel Cells)	2
General and Intangible	12
Total	227

TURN argues that the Commission should not adopt any increases 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 TY 2021 and in the following attrition years. TURN argues that depreciation does not affect the utility's ability to provide safe and reliable service. TURN also notes that denying the requested increases would mean that SCE continues to collect approximately \$1.6 billion in annual depreciation and decommissioning expense. If the Commission were to authorize increases, TURN argues that the increases should not exceed the amounts recommended by TURN, consistent with the Commission's commitment to gradualism in this area.

¹⁶⁸³ This amount understates SCE's proposed depreciation expense for 2021 because it is based on YE 2018 plant balances and does not account for subsequent plant growth.

¹⁶⁸⁴ Ex. SCE-18, Vol. 3, at 1, Table I-1. The dollar impacts are based on YE 2018 plant balances.

43.1. T&D Net Salvage

Net salvage is gross salvage less the cost to remove an asset from service at the end of its service life. Net salvage can be expressed either as a dollar amount or as a percent of the original plant cost (the net salvage rate (NSR)). Salvage and removal costs are based on current dollars (when the assets are removed from service), while retirements are based on historical dollars. Often, the net salvage for utility assets is a negative number (or percentage) because the cost of removing the assets from service exceeds any proceeds received from selling the assets.

SCE proposes annual net salvage accruals that would result in a \$199 million increase over currently authorized rates based on current YE 2018 plant balances. SCE's proposals for net salvage accruals are higher (more negative) for 11 accounts, and the same as authorized for 9 accounts. SCE explains that its proposals are based on an account-by-account analysis and are consistent with the straight-line remaining life methodology prescribed in SP U-4. SCE argues that net salvage rates have remained static for two GRC cycles resulting in an increasing gap between authorized and recorded net salvage rates. SCE also argues that failure to address this gap will result in future generations of customers bearing an increasingly higher share of costs to remove assets enjoyed by prior generations of customers.¹⁶⁸⁵

TURN and Cal Advocates argue that SCE's proposed increases do not reflect the principle of gradualism endorsed by the Commission in PG&E's 2014 GRC Decision, D.14-08-032.

¹⁶⁸⁵ SCE OB at 349.

TURN's primary recommendation is that the Commission adopt no change to existing net salvage rates as a step toward mitigating the impact of SCE's overall GRC request. In the alternative, TURN recommends limiting net salvage increases for the 11 accounts at issue to 25 percent of SCE's proposed increase, consistent with the gradualism approach used by the Commission in PG&E's 2014 GRC Decision.

Cal Advocates proposes to limit net salvage increases for FERC Accounts 365, 366, 367, and 368 based on application of the gradualism principle and offers various formulas as the basis of their recommendations. Regarding Accounts 365 and 366, Cal Advocates also notes that the potential for economies of scale or changes in future asset mix may result in declining rates in the future. Cal Advocates has reviewed and does not oppose SCE's net salvage proposals for the other FERC accounts within the Transmission Plant, Distribution Plant, and General Buildings categories.

The following table provides a summary of the currently authorized and parties' proposed accruals for the 11 contested accounts:¹⁶⁸⁶

¹⁶⁸⁶ Ex. SCE-18, Vol. 3 at 4, Table II-2.

FERC Acct No.	Description	Auth. NSR	SCE NSR	SCE Impact (\$M)	TURN NSR	Cal Adv NSR
Transmission Plant						
354	Towers and Fixtures	-60%	-80%	0.3	-65%	-80%
355	Poles and Fixtures	-72%	-90%	3.3	-77%	-90%
356	Overhead Conductors & Devices	-80%	-100%	1.4	-85%	-100%
358	Underground Conductors & Devices	-15%	-30%	1.3	-19%	-30%
Distribution Plant						
361	Structures and Improvements	-25%	-40%	2.2	-29%	-40%
362	Station Equipment	-25%	-40%	7.4	-29%	-40%
365	Overhead Conductors & Devices	-115%	-190%	29.8	-134%	-130%
366	Underground Conduit	-30%	-80%	25.8	-43%	-45%
367	Underground Conductors & Devices	-60%	-100%	68.1	-70%	-70%
368	Line Transformers	-20%	-50%	54.8	-28%	-25%
373	Street Lighting & Signal Systems	-30%	-50%	4.2	-35%	-50%
Total Impact (in millions)				\$199	\$50	\$60

SCE presents an account-by account analysis in support of its NSR proposals. TURN does not dispute SCE's underlying data, TURN's witness testifies that: "[t]he data provided by the Company indicate that the net salvage rates for the 11 accounts at issue should increase."¹⁶⁸⁷ With the exception of Accounts 365 and 366, Cal Advocates also does not dispute SCE's underlying data. However, Cal Advocates acknowledges that some increase to the net salvage rates for Accounts 365 and 366 is warranted. Therefore, the evidentiary record supports that the currently authorized net salvage rates for the identified 11 accounts are insufficient to recover future costs of removal.

¹⁶⁸⁷ Ex. TURN-08 at 42.

We find that some increase to net salvage for these 11 accounts during this GRC cycle is warranted. Although we are concerned about the overall rate impacts of SCE's requests for this GRC cycle, we are also mindful of the need to balance the equities of current and future ratepayers. SCE will ultimately need to recover the cost of removal associated with its capital expenditures. Given the evidence presented by SCE regarding increasingly negative net salvage rates, keeping the rates frozen for another GRC cycle would result in a disproportionate share of these removal costs being shifted to future ratepayers.

As noted by TURN and Cal Advocates, in PG&E's 2014 GRC, the Commission expressed concerns about the growing cost burdens associated with the increasing cost trends for negative net salvage and applied a principle of gradualism to these rates.¹⁶⁸⁸ The Commission explained that:

The principle of gradualism applies where there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase that would otherwise be warranted, all else being equal, and mitigates the short-term impact of large changes in depreciation parameters. Also, it is advisable to be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect.¹⁶⁸⁹

To balance the customers' respective cost burden between current and subsequent GRC cycles, the Commission found it reasonable in PG&E's 2014

¹⁶⁸⁸ D.14-08-032 at 597.

¹⁶⁸⁹ *Id.* at 598.

GRC to “adopt no more than 25 percent of the estimated net increase from current [net salvage] rates.”¹⁶⁹⁰

Citing PG&E’s 2014 GRC, the Commission also applied the gradualism principle in adopting net salvage rates in SCE’s 2015 GRC.¹⁶⁹¹ We continue to endorse the concept of gradualism with respect to net salvage rates for this rate case cycle given that the overall cost increases at issue in this GRC (for both Track 1 and Track 2) are substantial and ratepayers are facing a great deal of economic uncertainties associated with the global COVID-19 pandemic.¹⁶⁹² Even SCE recognizes that its requested net salvage rate increase is significant.¹⁶⁹³ In consideration of these factors and consistent with past Commission precedent, we find it reasonable to limit any net salvage increases to 25 percent of SCE’s requested increases.

Cal Advocates proposes NSRs for Accounts 365, 366, 367, and 368 based on application of the gradualism principle but bases each proposal on a different formula. Cal Advocates fails to justify the appropriateness of using different formulas for each of these accounts. We instead find reasonable the consistent approach set forth in TURN’s proposal.

43.2. T&D Average Service Life

SCE proposes to extend the average service lives (ASLs) for four of its T&D accounts: Accounts 361, 367, 373, and 390.¹⁶⁹⁴ SCE proposes to retain the ASL

¹⁶⁹⁰ *Id.* at 600.

¹⁶⁹¹ D.15-11-021 at 413, 421, and 425. The Commission did not apply the gradualism principle to SCE’s proposed NSRs in the 2018 GRC because it determined that no increases to NSRs were warranted.

¹⁶⁹² See TURN OB at 19-22; Cal Advocates OB at 281.

¹⁶⁹³ Ex. SCE-18, Vol. 3 at 3.

¹⁶⁹⁴ *Id.* at 15, Table III-6.

adopted in the prior GRC for the remainder of its T&D accounts. SCE's proposals result in a total of \$15.3 million less depreciation expense per year based on 2018 plant balances.¹⁶⁹⁵

TURN proposes service life adjustments to eight of SCE's T&D accounts, which would result in \$58.5 million less per year compared to present accruals based on 2018 plant balances.

The service lives and retirement frequency distributions authorized in the 2018 GRC and parties' proposed service lives and retirement frequency distributions are summarized in the following table:¹⁶⁹⁶

¹⁶⁹⁵ *Id.* at 15, Table III-6.

¹⁶⁹⁶ The first number in the last three columns is the average service life. The L, R, and SC classifications denote whether the mode of the retirement frequency curves to the left, right, or coincident with average service life, respectively. (Ex. TURN-09, Appendix B at 55.) The numbers following each letter represent the variation of life with a lower number indicating a relatively low mode, large variation, and large maximum life; and a higher number indicating a relatively high mode, small variation, and small maximum life. (*Id.* at 57.)

FERC Acct	Description	2018 GRC	SCE Proposal	TURN Proposal
TRANSMISSION PLANT				
352	Structures & Improvements	55 L 1.0	55 L 1.0	58 L 0.5
353	Station Equipment	45 R 0.5	45 L 0.5	
354	Towers & Fixtures	65 R 5.0	65 R 5.0	69 R 5.0
355	Poles & Fixtures	65 SC	65 SC	
356	Overhead Conductors & Devices	61 R 3.0	61 R 3.0	65 R 3.0
357	Underground Conduit	55 R 3.0	55 R 3.0	
358	Underground Conductors & Devices	45 S 1.0	45 S 1.0	
359	Roads & Trails	60 R 5.0	60 R 5.0	
DISTRIBUTION PLANT				
361	Structures & Improvements	50 L 0.5	55 L 0.5	58 L 0
362	Station Equipment	65 L 0.5	65 S -0.5	67 L 0
364	Poles, Towers & Fixtures	55 R 1.0	55 R 1.0	
365	Overhead Conductors & Devices	55 R 0.5	55 R 0.5	
366	Underground Conduit	59 R 3.0	59 R 3.0	64 R 2.5
367	Underground Conductors & Devices	43 R 1.5	47 L 1.0	
368	Line Transformers	33 S 1.5	33 S 1.5	
369	Services	55 R 1.5	55 R 1.5	60 R 1.5
370	Meters	20 R 3.0	20 R 3.0	30 R 3.0
371	Install on Customer Premises	55 R 1.5	55 R 1.5	
373	Street Lighting & Signal Systems	48 L 1.0	50 L 0.5	
GENERAL BUILDINGS				
390	Structures & Improvements	45 R 0.5	50 SC	

Both SCE and TURN rely on methodologies that are not readily verifiable or able to be replicated. Both SCE's and TURN's recommendations rely to a large degree on judgment that is not adequately explained or justified.

TURN's analysis relies on a "retirement rate method" and uses aged property data provided by SCE to develop an observed life table (OLT) curve for each T&D plant account, then engages in a curve fitting process to select the

Iowa curve that best fits the OLT curve.¹⁶⁹⁷ However, TURN does not always rely on the best fitting curves but in some instances relies on visual and mathematical techniques in combination with professional judgment, which is not adequately explained or justified. Moreover, to the extent that there is irregular or minimal retirement activity in an account, past retirement activity alone may not be a reliable indicator of future retirements.

On the other hand, there is merit to TURN's criticisms that SCE's study is overly complicated and is not explained with sufficient detail and clarity that would enable the Commissioners or their staff to achieve the necessary level of understanding or ability to replicate. SCE's method statistically estimates population parameters by drawing inferences and predictions based on an analysis of samples drawn from parent populations.¹⁶⁹⁸ Although SCE generally describes the methodology used, SCE does not provide sufficient information that would enable the Commission to replicate or verify the results. Furthermore, the statistical analyses were not conclusive for several accounts, and therefore, the final recommendations for those accounts do not appear to be based on the statistical analyses at all.

Given the above considerations, we do not endorse either methodology as the superior methodology. We evaluate SCE's and TURN's proposals for each contested account in light of observed retirement activity, composition of the

¹⁶⁹⁷ TURN's curve fitting process relies on Iowa curves, which are a set of commonly used survivor curves developed over several decades of extensive analysis of utility and industrial property. A survivor curve is a graph of the percent of units remaining in service expressed as a function of age. (Ex. TURN-08, Appendix B at 52.) TURN provides a detailed description of Iowa curves in Ex. TURN-08, Appendix B and the curve fitting process in Ex. TURN-08, Appendix C.

¹⁶⁹⁸ Ex. SCE-18, Vol. 3 at 19.

accounts, and other available information to determine the reasonableness of the proposals.

43.2.1. Account 352 (Structures and Improvements)

SCE recommends retaining an ASL of 55 years for Account 352, whereas TURN recommends extending the ASL to 58 years. We do not find evidence of any major factors that would change the appropriateness of the ASL adopted in the last GRC, and therefore, retain the previously authorized ASL of 55 years.

We do not find TURN's analysis based on past retirement activity in the account to be persuasive. The amount of weight to be given to past retirement activity is dependent on the extent to which that activity is likely to be descriptive of future retirements. 58.5 percent of total adjusted retirements in this account were associated with a single retirement of equipment at one substation (Sylmar). We agree with SCE that TURN's analysis over-weights what is likely anomalous retirement activity.¹⁶⁹⁹

43.2.2. Account 354 (Towers and Fixtures)

SCE recommends retaining an ASL of 65 years for Account 354, whereas TURN recommends extending the ASL to 69 years. We do not find evidence of any major factors that would change the appropriateness of the ASL adopted in the last GRC, and therefore, retain the previously authorized ASL of 65 years. We do not find TURN's analysis based on past retirement activity to be persuasive given the minimal retirement activity (0.3 percent of derived additions) recorded in this account.¹⁷⁰⁰

¹⁶⁹⁹ *Id.* at 25.

¹⁷⁰⁰ Ex. SCE-07, Vol. 3, Appendix A at A-14.

43.2.3. Account 356 (Overhead Conductors and Devices)

SCE recommends retaining an ASL of 61 years for Account 356, whereas TURN recommends extending the ASL to 65 years. We do not find evidence of any major factors that would change the appropriateness of the ASL adopted in the last GRC, and therefore, retain the previously authorized ASL of 61 years. We do not find TURN's analysis based on past retirement activity to be persuasive given the minimal retirement activity (1.9 percent of derived additions) recorded in this account.¹⁷⁰¹

43.2.4. Account 361 (Distribution Structures and Improvements)

SCE recommends extending the ASL for Account 361 from 50 to 55 years, whereas TURN recommends extending the ASL to 58 years. We adopt an ASL of 56 years based on evidence that the 56-L0 curve falls within the range of the parties' proposals and has the closest mathematical fit to the OLT.

This account contains adequate retirement history with a relatively smooth and well-shaped curve.¹⁷⁰² SCE's testimony supports the conclusion that future forces of retirement are not likely to significantly differ from those observed in the past.¹⁷⁰³ Therefore, we find it appropriate to use past retirement activity to predict the ASL for this account.

Given the lack of clarity regarding SCE's methodology, we find that SCE has failed to adequately justify its use of a 55-year ASL. TURN's proposed curve results in a better mathematical fit to the OLT compared to SCE's proposal. However, SCE presented evidence that the 56-L0 curve provides the best

¹⁷⁰¹ *Id.* at A-18.

¹⁷⁰² Ex. TURN-08 at 23-24.

¹⁷⁰³ Ex. SCE-07, Vol. 3, Appendix A at A-26.

mathematical fit to the OLT¹⁷⁰⁴ and TURN provides no justification as to why its proposed curve would be superior to the one with the best mathematical fit. Given this lack of justification, we find it reasonable to adopt the 56-L0 curve for this account.

43.2.5. Account 362 (Station Equipment)

SCE recommends retaining an ASL of 65 years for Account 362 but recommends a projection-life curve of 65-S-.5 as opposed to the currently authorized 65-L0.5 curve. TURN recommends an ASL of 67 years. TURN argues that the OLT curve for Account 362 is relatively smooth and complete, which makes selection of a close-fitting Iowa curve a straightforward process.¹⁷⁰⁵

This account contains adequate retirement history with a relatively smooth and well-shaped curve. SCE's testimony supports the conclusion that future forces of retirement are not likely to significantly differ from those observed in the past.¹⁷⁰⁶ Therefore, we find it appropriate to use past retirement activity to predict the ASL for this account.

Given the lack of clarity regarding SCE's methodology, we find that SCE has failed to adequately justify its recommendation of a projection-life curve of 65-S-.5. Therefore, we adopt TURN's proposed curve, which results in a better mathematical fit to the OLT compared to SCE's proposal.¹⁷⁰⁷

¹⁷⁰⁴ Ex. SCE-18, Vol. 3 at 23, Table III-8.

¹⁷⁰⁵ Ex. TURN-08 at 28.

¹⁷⁰⁶ Ex. SCE-07, Vol. 3, Appendix A at A-28.

¹⁷⁰⁷ SCE presents evidence that the curve with the best mathematical fit would be the 68-L0 curve. (Ex. SCE-18, Vol. 3 at 23, Table III-8.) However, we decline to adopt this curve given that it falls outside the range of both parties' recommendations.

43.2.6. Account 366 (Underground Conduit)

SCE recommends retaining a service life of 59 years for Account 366, whereas TURN recommends extending the service life to 64 years. Due to the minimal retirements recorded in this account (2.4 percent of derived additions) and the unreliable service-life indications, SCE's expert deferred to SCE staff in recommending retention of the currently approved service-life parameters.¹⁷⁰⁸ TURN argues that its recommended curve has a better visual and mathematical fit to the OLT curve. TURN also argues that an ASL in excess of 60 years is strongly indicated given that the OLT shows that over 70 percent of the assets in this account are surviving at age 60.

We do not find TURN's analysis to be persuasive given that it is based on minimal retirements recorded in this account and an OLT curve that does not appear well-suited to the curve fitting process.¹⁷⁰⁹

Although SCE's statistical study was not determinative, we find that SCE has adequately supported its proposal to retain the previously authorized service life of 59 years. This account is comprised of conduit (44 percent), pull and slab boxes (23 percent), vaults (21 percent), and other various equipment.¹⁷¹⁰ SCE presents an engineering survey that indicates an expected or design life of 45-60 years for conduit, 20 years for pull and slab boxes, and 50 years for vaults.¹⁷¹¹ The engineers state that retirement factors are largely related to deterioration-related factors, but that other factors will reduce the expected life of these assets, such as mechanical damage from excavation, drilling crews

¹⁷⁰⁸ Ex. SCE-07, Vol. 3, Appendix A at A-34.

¹⁷⁰⁹ See Ex. TURN-08 at 31.

¹⁷¹⁰ Ex. SCE-07, Vol. 3, Appendix A at A-33.

¹⁷¹¹ Ex. SCE-07, Vol. 3, WP Bk A at 224.

inadvertently digging into conduit, or conductor failure. In the absence of compelling statistical analyses from either party, we find that this uncontroverted evidence supports the reasonableness of retaining the 59-year ASL for this account.

43.2.7. Account 369 (Services)

SCE recommends retaining a service life of 55 years for Account 369, whereas TURN recommends extending the service life to 60 years. SCE argues that there is minimal retirement experience (2.6 percent of derived additions) from which to draw conclusions about the ASL for this account and that TURN's proposal, which goes beyond the industry average of 50 years, is unreasonable based on such limited data.

TURN notes that selecting an Iowa curve that provides a very close fit to the OLT curve would result in an ASL that is notably longer than those observed in the industry for this account.¹⁷¹² However, TURN argues that the OLT strongly indicates an ASL going forward of longer than 55 years and that its proposal is a better mathematical fit than SCE's proposal and represents a good balance between the current indications of ASL and the possibility that the ASL may decline going forward.¹⁷¹³

We do not find TURN's analysis based on curve fitting to the OLT to be persuasive. TURN acknowledges that the retirement history in this account is not ideal for conventional Iowa curve fitting techniques.¹⁷¹⁴ Moreover, TURN's proposed curve is not the curve with the best mathematical or visual fit,¹⁷¹⁵ and is

¹⁷¹² Ex. TURN-08 at 34.

¹⁷¹³ *Id.* at 35.

¹⁷¹⁴ *Id.* at 34.

¹⁷¹⁵ See Ex. SCE-18, Vol. 3 at 23, Table III-8.

based largely on the judgment of TURN's expert. The basis for the expert's judgment that TURN's proposed curve represents a good balance between current indications of ASL and the possibility that the ASL may decline going forward is not adequately explained or justified. Therefore, we find that there is a lack of justification for TURN's proposed ASL of 60 years.

We do not find evidence of any major factors that would change the appropriateness of the ASL adopted in the last GRC, and therefore, retain the previously authorized ASL of 55 years.

43.2.8. Account 370 (Meters)

SCE recommends retaining a service life of 20 years for Account 370, whereas TURN recommends extending the service life to 30 years. The evidentiary record does not support concluding that the previously adopted service life of 20 years should be modified, and therefore, we retain a 20-year service life for this account.

We do not find compelling justification for TURN's proposed 30-year ASL. TURN itself acknowledges that this account does not have adequate retirement history for conventional Iowa curve fitting techniques.¹⁷¹⁶ TURN argues that 99 percent of the assets in this account that have reached beyond 30 years are still surviving, which indicates that the ASL will be longer than SCE has proposed going forward. However, SCE notes that this portion of the account makes up only 1.8 percent of the account and that the vast majority of the account consists of recently deployed Advanced Metering Infrastructure (AMI) meters.¹⁷¹⁷

¹⁷¹⁶ Ex. TURN-08 at 37.

¹⁷¹⁷ Ex. SCE-07, Vol. 3, Appendix A at A-41; Ex. SCE-18, Vol. 3 at 27; Ex. TURN-08, Ex. DJG-14 at 30-32.

Evidence presented by SCE that TURN's proposal would place SCE above the industry average and the ASLs adopted for SDG&E and PG&E of 16 years and 20 years, respectively, for the same account further supports the reasonableness of retaining the 20-year ASL for this account.¹⁷¹⁸

43.2.9. Uncontested Accounts

SCE's proposals to extend the service lives for Accounts 367, 373, and 390 are not contested. We find that SCE has made a *prima facie* showing of the reasonableness of these proposals and approve the service life extensions.

SCE's proposals to retain the service lives for the remainder of the T&D accounts are uncontested and are approved. There is no evidence that there have been any major changes since the last GRC that would warrant changes to these previously adopted parameters.

43.3. Small Hydro Decommissioning

SCE requests \$27.4 million in annual accruals for future decommissioning of the 22 small hydro plants in its hydro portfolio.¹⁷¹⁹ SCE uses the U.S. Bureau of Reclamation's Risk Management Best Practices and Risk Methodology to assign each small hydro plant a decommissioning probability of 1 percent (for virtually impossible), 10 percent (for very unlikely), 50 percent (for equally likely), 90 percent (for very likely) or 99 percent (for virtually certain). SCE calculates the requested annual accrual by multiplying each facility's decommissioning cost estimate by its decommissioning probability, escalating the probability-adjusted estimate to the average year decommissioning activities

¹⁷¹⁸ Ex. SCE-18, Vol. 3 at 28-29; Ex. TURN-74.

¹⁷¹⁹ Ex. SCE-54 at 252. SCE's original request was for \$29.6 million. SCE subsequently adjusted the original request to \$27.4 by applying \$31 million of anticipated cash contributions from the Army Corps of Engineers (ACOE) as a reduction to the total cost of decommissioning.

are expected to take place, and then dividing the escalated estimate by the estimated remaining time to decommissioning.¹⁷²⁰

SCE argues that it is reasonable to begin collecting these costs in 2021 because the continued cost effectiveness of small hydro is uncertain and decommissioning costs will likely be significant. SCE argue that its proposal is designed to address intergenerational equity by collecting costs associated with an asset from the customers who benefit from the asset, and to avoid a rate shock effect associated with collecting high future costs within a compressed period.

The intervenor parties do not dispute the appropriateness of permitting SCE to begin accruing funds for the potential future decommissioning of some of its small hydro facilities. However, TURN and Cal Advocates both propose to limit SCE's requested increase to plants with the highest probability of decommissioning: Borel Powerhouse (99 percent probability) and Rush Creek (Agnew Lake and Rush Meadows, 90 percent probability). TURN recommends an annual accrual of \$10.1 million for these plants.¹⁷²¹ Cal Advocates recommends an annual accrual of \$6.1 million¹⁷²² for Borel and \$2.6 million for Agnew Lake and Rush Meadows dams.

TURN and Cal Advocates do not dispute SCE's probability-adjusted decommissioning cost estimates for Agnew Lake and Rush Meadows. Moreover, there is no longer a dispute regarding the decommissioning cost

¹⁷²⁰ Ex. SCE-07, Vol. 3 at 81 and 82, Table V-31.

¹⁷²¹ Ex. SCE-54 at 252.

¹⁷²² Cal Advocates initially recommended that the Commission reduce SCE's cost estimate for Borel by 50 percent and authorize an annual accrual of \$4.1 million given uncertainty regarding the ACOE's contributions to decommissioning. Based on more recent information that the ACOE's contributions will be \$31 million, Cal Advocates now recommends a \$31 million reduction to SCE's requested costs for Borel, which results in an annual accrual of \$6.1 million in present dollars. (Cal Advocates OB at 290.)

estimate for Borel because SCE, TURN, and Cal Advocates all agree that SCE's original cost estimate should be adjusted by \$31 million to account for anticipated contributions from the ACOE.¹⁷²³ The difference in TURN's and Cal Advocates' recommendations stem from the fact that TURN's calculations are based on the use of 2023 dollars whereas Cal Advocates' calculations are based on the use of present dollars.

We find it reasonable for SCE to begin recovery for the Borel Powerhouse, Agnew Lake Dam, and Rush Meadows Dam given the high probability that decommissioning of these plants will take place within the next 10 years and the significant costs of decommissioning. SCE estimates a 99 percent probability that it will initiate decommissioning of Borel within the next 5 years and a 90 percent probability that it will initiate decommissioning of Rush Meadows and Agnew Lake within the next 5-10 years. We approve the undisputed probability-adjusted decommissioning cost estimates of \$85.2 million (\$2018)¹⁷²⁴ for Borel and \$41.7 million (\$2018) for Agnew Lake and Rush Meadows.¹⁷²⁵ For the reasons discussed below, we adopt an escalation rate of 4 percent through 2024 for these costs. We do not find any basis for Cal Advocates' recommendation that present dollars be used to calculate these costs. SCE shall also continue to use the broad group depreciation procedure for the removal costs.

¹⁷²³ SCE OB at 373; TURN OB at 310; Cal Advocates OB at 290.

¹⁷²⁴ This figure accounts for the \$31 million contribution from ACOE. (Original cost estimate of \$117.1 million - \$31 million = \$86.1 million. \$86.1 million x decommissioning probability of 99 percent = \$85.2 million.)

¹⁷²⁵ Ex. SCE-05 at 117, Table II-38.

SCE estimates a 50 percent probability of decommissioning for 3 plants (Gem Lake, Kaweah 3, and Tule) and a 10 percent probability of decommissioning for the remainder of its small hydro plants.¹⁷²⁶ With regard to the plants assigned a 50 percent probability, SCE explains that the financial and economic analyses of the costs to decommission versus the costs to continue operations do not point strongly in either direction.¹⁷²⁷ With regard to the plants assigned a 10 percent probability, “SCE generally anticipates that relicensing will be economically preferable to decommissioning.”¹⁷²⁸ Given the degree of uncertainty regarding when SCE may initiate decommissioning of these plants, the Commission finds that SCE does not present sufficient justification to begin recovery of decommissioning costs for these plants at this time.

43.4. Decommissioning Escalation

SCE proposes to escalate generation decommissioning estimates to the estimated end of the service life using Handy-Whitman escalation factors for both historical and future periods. SCE argues that its proposal is consistent with SP U-4, which recognizes that straight-line recovery assumes that accruals are pinned to the date of retirement. SCE recognizes that the Commission reached a different conclusion about escalation in the last GRC decision, D.19-05-020, but argues that the last GRC’s outcome is not consistent with SP U-4 and was a departure from prior Commission precedent.

TURN argues that, consistent with the treatment adopted in D.19-05-020, the Commission should calculate future generation decommissioning expense in

¹⁷²⁶ *Ibid.*

¹⁷²⁷ *Id.* at 119-120.

¹⁷²⁸ *Id.* at 120.

2023 dollars, the original end of the GRC cycle.¹⁷²⁹ Alternatively, should the Commission choose not to follow the approach adopted in D.19-05-020, TURN argues that the Handy-Whitman escalation rate is not appropriate for purposes of escalating plant demolition and removal costs because it was developed as a construction cost index for gas turbine peaker plants and historically is much higher than general inflation. TURN instead recommends that the Commission use a 4 percent rate for the 2003-2019 escalation.

We agree with TURN that the approach adopted in D.19-05-020 for calculating generation decommissioning costs should be retained. Given that the rate case cycle is now extended through 2024, we find it appropriate to calculate future generation decommissioning expense in 2024 dollars. In contrast to SCE's proposal, the approach adopted in D.19-05-020 appropriately accounts for the time value of money and avoids the result of current ratepayers paying on a vastly overinflated expense.

SCE's arguments that this approach would result in exponential growth and excessive deferral to future customers are not persuasive. In its rebuttal testimony, SCE provides an illustrative example of what it claims is its straight-line proposal versus TURN's inflation-deferred proposal.¹⁷³⁰ Although the example may be an accurate representation of SCE's straight-line proposal, it is not an accurate representation of TURN's inflation-deferred proposal.

In SCE's example, costs totaling \$100,000 are collected over a 20-year period. Under SCE's straight-line proposal, these costs are equally spread over the 20-year period with customers in each year paying \$5,000. However, since

¹⁷²⁹ In D.20-01-002, the Commission extended the GRC cycle for large energy utilities from 3 to 4 years.

¹⁷³⁰ Ex. SCE-18 at 36, Table V-11.

each year's costs are in nominal dollars, the value of the \$5,000 paid by customers in Year 1 would be much higher than the value of the \$5,000 paid in Year 20 with cheaper nominal dollars.

In providing an illustration of TURN's proposal, SCE assumes that the utility will also collect costs totaling \$100,000 over a 20-year period. SCE then presents a calculation in which \$2,373 is collected in Year 1 with the amount continuing to grow each year until \$14,081 is collected in Year 20. SCE incorrectly assumes that the total amount to be collected over a 20-year period under TURN's method would be the same as under the straight-line method. The \$100,000 is an overinflated figure because it is based on escalating costs through to Year 20 whereas under TURN's proposal, costs would only be escalated through the end of the GRC cycle. SCE's illustration of TURN's proposal also does not account for the fact that the Commission recalculates the accrual every GRC cycle.

Accounting for the time value of money over the course of the 20-year period would result in costs totaling significantly less than \$100,000. Therefore, although we would expect to see increased deferrals to future customers under TURN's proposal, we would expect these increases to be much more modest than presented in SCE's example. It is reasonable to require future ratepayers who will be paying in cheaper nominal dollars to pay more than current ratepayers paying in 2021-2024 dollars in order to account for the time value of money. For example, TURN's testimony notes that for Mountainview, a dollar in the expected retirement year of 2040 is worth about 68 cents in 2021 dollars.¹⁷³¹

¹⁷³¹ Ex. TURN-09 at 34.

TURN recommends that the Commission use a 4 percent rate of escalation only if the Commission rejects the approach adopted in D.19-05-020. Although we retain the approach adopted in D.19-05-020, we adopt a 4 percent rate of escalation because we find that SCE has not justified use of the Handy-Whitman escalation rate for decommissioning costs. TURN's testimony notes that the Handy-Whitman index includes escalation for the cost of materials in addition to costs for labor and other ancillary construction equipment required for demolition.¹⁷³² The Commission finds TURN's recommendation of 4 percent escalation, which is based on data regarding national construction wages, to be more appropriate for escalation of decommissioning costs. This escalation rate shall apply to historical escalation, except for SCE's small hydro assets,¹⁷³³ as well as for future escalation through 2024.

TURN also recommends that SCE conduct fresh decommissioning studies for Mountainview, a representative peaker, and a representative solar plant for its next GRC given that it has been 10-18 years since the most recent studies. SCE agrees to undertake these additional studies.¹⁷³⁴

43.5. Perris Decommissioning

SCE owns and operates 25 solar generating plants with a total capacity of 91.4 MW DC as part of the Solar Photovoltaic Program (SPVP) authorized in D.09-06-049.¹⁷³⁵ The largest project in the SPVP is the Perris solar project (10.2 MW DC), which was installed by SCE in 2012 at an investment of

¹⁷³² *Id.* at 35.

¹⁷³³ Parties did not address historical escalation for SCE's small hydro assets because SCE provided its decommissioning estimates in 2018 dollars.

¹⁷³⁴ SCE OB at 375, fn. 2114.

¹⁷³⁵ Ex. SCE-05, Vol. 1 at 164-165.

\$39.8 million. SCE negotiated a 20-year lease for the project but decommissioned the facility after seven years because SCE determined that it was uneconomic to reinstall the assets after the building owner decided to replace the rooftop. In past GRCs, the Commission has authorized SCE's use of group accounting for the 25 solar projects in the SPVP.

SCE proposes to continue group accounting treatment for all 25 SPVP assets consistent with SP U-4 and to recover the decommissioning costs and undepreciated costs of the Perris investment, plus a full rate of return, over the 10.7-year remaining life of the overall group of solar assets.¹⁷³⁶

TURN argues that SCE's proposed ratemaking treatment of Perris unreasonably assigns the full costs of the prematurely retired facility to ratepayers. TURN argues that it was uncertain whether the rooftop was expected to last 20 years without replacement or major repair and that it was unreasonable for SCE to execute a 20-year lease that gave the building owner the right to unilaterally require removal of the project at SCE's sole expense if the building owner desired repairs or replacement of the roof. TURN recommends that the Commission: (1) limit the recovery of decommissioning costs to those incurred to date (\$3.81 million as opposed to the \$6.5 million forecasted by SCE); (2) deny mass property treatment to Perris and authorize recovery of the remaining net plant over six years with no return on equity or debt, and (3) direct SCE to pursue any legitimate damage claims against the building owner with 95 percent of the proceeds credited to ratepayers.

Based on SCE's requested decommissioning costs of \$6.5 million, SCE's proposal would result in a total annual revenue requirement of \$5.081 million

¹⁷³⁶ Ex. SCE-18, Vol. 3 at 39.

consisting of \$2.537 million proposed depreciation expense and \$2.544 million pre-tax return on rate base. TURN's proposal would result in a total annual revenue requirement of \$4.507 million for proposed depreciation expense with no return on tax base.¹⁷³⁷

43.5.1. Decommissioning Costs

TURN argues that SCE's forecasted decommissioning cost of \$6.5 million for the Perris facility appears to be well in excess of the expected cost of decommissioning. TURN notes that project decommissioning was complete at the end of June 2020, and SCE had incurred \$3.81 million in decommissioning costs. TURN argues that it is unclear what additional work will be required and that SCE has failed to provide an estimate of remaining costs.

SCE bears the burden of establishing that its requested costs are justified. Here, SCE has failed to provide justification for the \$6.5 million forecast. The latest information in the record regarding the decommissioning costs indicates that SCE recorded \$3.81 million in costs through June 24, 2020.¹⁷³⁸ In data request responses to TURN in May and June 2020, SCE stated that it had completed physical decommissioning of the Perris facility but that the recorded costs are not final because SCE is addressing building restoration issues with the lessor.¹⁷³⁹ In the responses, SCE was unable to identify what additional work would be required or any estimates for the remaining work.¹⁷⁴⁰ During hearings, SCE's witnesses testified that the decommissioning work was essentially

¹⁷³⁷ *Id.* at 40, Table VI-12.

¹⁷³⁸ Ex. TURN-46, SCE response to data request TURN-SCE 91, Q14.

¹⁷³⁹ Ex. TURN-46, SCE responses to data requests TURN-SCE 75, Q3 and TURN-SCE 91, Q14.

¹⁷⁴⁰ *Ibid.*

complete and that they were unaware of any additional restoration work that would be required.¹⁷⁴¹

Because SCE has failed to provide an estimate of what additional decommissioning costs will be incurred, we find that SCE has failed to justify its requested decommissioning costs of \$6.5 million. Therefore, we authorize recovery of the recorded decommissioning costs of \$3.81 million. If SCE incurs additional costs, it may present updated decommissioning costs in its next GRC.

43.5.2. Ratemaking Treatment

We agree with TURN that it is inappropriate for SCE to continue to receive a return on the Perris investment because it has been decommissioned and is no longer used and useful. It is a “longstanding regulatory principle that shareholders should earn a return only on used and useful plant.”¹⁷⁴² TURN cites to a long line of Commission precedent in which we have denied any return on unrecovered capital of prematurely retired plant.¹⁷⁴³ The Commission has explained:

[I]n 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.¹⁷⁴⁴

The Commission has on occasion made exceptions to this general policy. In making such exceptions, the Commission has emphasized that the specific

¹⁷⁴¹ RT, Vol. 5 at 713: 11-14, 18-24; RT, Vol 9 at 988: 21-23.

¹⁷⁴² D.92-12-057, 1992 Cal. PUC LEXIS 971 at *83.

¹⁷⁴³ TURN OB at 323-324.

¹⁷⁴⁴ D.85-08-046, 1985 Cal. PUC LEXIS 687 at *22.

circumstances of each situation must be evaluated.¹⁷⁴⁵ As explained by the Commission: “It would be poor public policy to include large amounts of plant that is not used and useful in rate base without a full analysis and consideration of the specific facts and circumstances.”¹⁷⁴⁶

SCE argues that Perris has always been part of a larger depreciable group and that it is inconsistent with group depreciation principles to disallow earlier than average retirement and otherwise leave the group intact. SP U-4 states that under group accounting, “A deficiency due to early retirement of a particular unit is made up through greater accruals on a unit which outlives the average.”¹⁷⁴⁷ SCE argues that midstream changes would change the way group depreciation works.

We reject the notion that prior group accounting treatment of plant is alone sufficient to justify an exception to the general policy that utilities should only earn a return on plant that is used and useful, particularly in cases involving a large standalone project or large amounts of plant. Such a notion is not consistent with Commission precedent. The Commission has stated that the specific circumstances must be evaluated and that it is appropriate for the Commission to “critically review the use of group accounting and its alternatives” in instances where it appears that the undepreciated balances of premature plant retirements would not be offset to a large degree by plant assets that exceed their expected lives.¹⁷⁴⁸ TURN cites to Commission precedent in which the Commission endorsed the used and useful principle over the

¹⁷⁴⁵ D.11-05-018 at 55.

¹⁷⁴⁶ *Id.* at 66-67.

¹⁷⁴⁷ SP U-4, ch. 3 at 8.

¹⁷⁴⁸ D.11-05-018 at 64.

importance of maintaining group depreciation.¹⁷⁴⁹ Therefore, the fact that Perris was previously afforded group accounting treatment is not controlling.

With respect to the Perris facility, SCE fails to justify an exception from the general policy that only used and useful plant should earn a return. In prior decisions, the Commission considered factors such as the causes of the premature retirement and the burdens and benefits of the plant items in question in determining appropriate ratemaking treatment. Consideration of these factors does not weigh in favor of authorizing a continued return on the no longer used and useful Perris facility.

The Commission has found it appropriate to authorize a return on prematurely retired plant in instances where the retirement was due to Commission desires or actions, and to deny a return on rate base when the impetus for the non-used and useful status was utility actions rather than Commission desires or actions.¹⁷⁵⁰ In this case, the impetus for the decommissioning of the Perris facility was not due to Commission desires or actions.

The Commission has also found it appropriate to authorize a return on prematurely retired plant in instances where the abandonment results in a net benefit to ratepayers.¹⁷⁵¹ In this case, there is no demonstration that the premature retirement results in net benefits to ratepayers. Ratepayers will continue to pay for the plant's direct costs although they are not receiving any benefits from the plant. In addition, Perris is a large stand-alone solar project and it is unlikely that the undepreciated balance of Perris would be offset to a

¹⁷⁴⁹ TURN RB at 159-160 citing D.85-12-108 and D.92-12-057.

¹⁷⁵⁰ D.11-05-018 at 55-57.

¹⁷⁵¹ D.11-05-018 at 57.

large degree by the other SPVP assets that exceed their expected lives since the ASL for these assets is based largely on the lease terms for the rooftops.¹⁷⁵²

Under these circumstances, we do not find it consistent with Commission precedent or a fair division of risks and benefits for ratepayers to also pay for the return on the undepreciated plant balance of \$20.54 million and decommissioning costs of \$3.81 million for over a decade.¹⁷⁵³ Therefore, we adopt TURN's proposal 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. Such ratemaking treatment is consistent with past treatment the Commission has adopted for similar circumstances.¹⁷⁵⁴

Given that the mass property treatment of the other 24 solar PV assets is not disputed, we find it reasonable for SCE to continue the use of group accounting for these assets. We also find that the early retirement of the Perris facility should not impact the ASL for the other solar PV assets since the ASL is based largely on the lease terms for the rooftops.¹⁷⁵⁵

43.5.3. Future Damage Claims

TURN argues that SCE should aggressively pursue any legitimate claims against the facility owner and credit 95 percent of any proceeds to ratepayers.

¹⁷⁵² Ex. SCE-07, Vol. 3 at 85.

¹⁷⁵³ Ex. SCE-18, Vol. 3 at 40, Table VI-12.

¹⁷⁵⁴ For example, in both D.85-12-108 and D.92-12-057, the Commission removed the undepreciated balance of prematurely retired plants from rate base and amortized the recovery of the balance over five years with no return or interest earned. (D.85-12-108, 1985 Cal. PUC LEXIS 1112 at *57-*58; D.92-12-057, 1992 Cal. PUC LEXIS 971 at *74, *83-*84.)

¹⁷⁵⁵ Ex. SCE-07, Vol. 3 at 85.

SCE agrees to return 100 percent of all proceeds that may be recovered from legal action to customers if SCE's proposals for the Perris facility are adopted.

As discussed above, we do not adopt SCE's ratemaking proposals for the Perris facility. Under the ratemaking treatment adopted in this decision, the project risks are being shared between ratepayers and shareholders. Therefore, in the event that SCE recovers any proceeds from legal action related to the Perris facility, we determine that a reasonable division would be a 50/50 allocation between ratepayers and shareholders.

43.6. Palo Verde Interim Retirements

SCE proposes to increase the interim retirement net salvage rates for Palo Verde based on a 10-year average (2009-2018) of retirements and net salvage experience. SCE's proposal results in an interim retirement rate of 0.55 percent, an interim net salvage rate of -24 percent, and an annual accrual of \$19.8 million.

TURN recommends using 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. TURN's proposal would result in an interim retirement rate of 0.20 percent, an interim net salvage rate of -40 percent, and an annual accrual of \$18.0 million.

We find reasonable and adopt TURN's proposal to base the interim retirement net salvage rate on the 7-year average. SCE does not provide sufficient evidence to support that the high level of interim retirements recorded in 2011 are likely to recur in the future. In rebuttal testimony, SCE asserts that: "APS indicates that in the next ten years three evaporative pond liners will

require replacement at a cost of approximately \$30 million each.”¹⁷⁵⁶ SCE does not provide any additional information in support of this assertion. Therefore, there is insufficient information for the Commission to evaluate the likelihood that such replacements will occur at the cost estimate provided. SCE’s capital cost forecast has not identified costs for any major projects that would occur during this GRC cycle.

43.7. Fuel Cell Generation

SCE seeks to recover \$3.0 million of future decommissioning expense for two fuel cells it owns and operates located at California State University, San Bernardino and University of California, Santa Barbara. SCE is obligated to remove the facilities if the universities choose not to retain ownership of the facilities at the end of the lease terms in 2023. Until this rate case, SCE assumed that it would transfer ownership of the fuel cells to the host sites, but SCE now believes that assumption may prove incorrect. SCE states that any unspent removal costs would be returned to customers.

TURN recommends reducing SCE’s forecasted decommissioning cost by 50 percent given the uncertainty about whether SCE will be required to remove the fuel cells. TURN also recommends reducing the contingency associated with these jobs from 25 percent to 15 percent, which is comparable to approaches used by PG&E and SDG&E. Adoption of TURN’s recommendations would result in recovery of \$1.36 million.

SCE states that it has not received any formal communications from the universities regarding their plans but that “other considerations lead SCE to

¹⁷⁵⁶ Ex. SCE-18, Vol. 3 at 49.

believe that decommissioning will be required at the end of the leases.”¹⁷⁵⁷ Based on the information provided by SCE, the likelihood of decommissioning at both locations is uncertain. Given this uncertainty, we find reasonable TURN’s proposal for recovery of 50 percent of SCE’s requested decommissioning costs during this GRC cycle. We also find that SCE has failed to justify use of a 25 percent contingency for removal of a small fuel cell installation and find TURN’s recommendation of a 15 percent contingency to be more reasonable. Although the expense is a relatively small amount and any unspent funds would be returned to ratepayers, we also consider the cumulative impact of all the rate requests during this GRC cycle.

44. Taxes

SCE’s proposed methodologies for forecasting tax expense were unopposed with the exception of the California property tax forecast disputed by Cal Advocates. We approve use of the uncontested methodologies for calculating tax expense set forth in Exhibit SCE-7, Volume 2A, Chapter IV.

With respect to the California property tax forecast, SCE initially proposed using a simple average method for the basis of the forecast. Cal Advocates proposes relying on a trend method based on the five prior recorded fiscal years, which is the method used in prior GRCs. SCE’s proposal results in a forecast of \$407.73 million, whereas Cal Advocates’ proposal results in a forecast of \$403.94 million.¹⁷⁵⁸ SCE states that it is willing to accept Cal Advocates’ proposal if Cal Advocates’ second proposal to establish a new memorandum account just for California property taxes is rejected.¹⁷⁵⁹ In its reply brief, Cal Advocates

¹⁷⁵⁷ Ex. SCE-18, Vol. 3 at 51.

¹⁷⁵⁸ Ex. SCE-18, Vol. 2E3 at 43.

¹⁷⁵⁹ SCE OB at 386.

withdrew its recommendation for a California property tax memorandum account.¹⁷⁶⁰

We find it reasonable to continue to use the five-year trend method for the California property tax forecast, and therefore, adopt Cal Advocates' proposed forecast. Given no apparent need for a California property tax memorandum account, we decline to adopt one.

SCE also proposes to extend the 2018 Tax Accounting Memorandum Account (2018 TAMA) in this rate case cycle. The 2018 TAMA is intended to track all differences between forecast and recorded income tax expenses so that the Commission can more closely examine revenue impacts caused by the utility's implementation of various tax laws, tax policies, tax accounting changes, or tax procedure changes.¹⁷⁶¹ In the 2018 GRC, the Commission ordered that the 2018 TAMA "shall remain open and the balance in the account shall be reviewed in every subsequent GRC until a Commission decision closes the account."¹⁷⁶² Continuation of the 2018 TAMA will continue to aid the Commission's review of the reasonableness of SCE's election of various tax changes. Therefore, we adopt SCE's unopposed proposal to continue the 2018 TAMA.

45. Other Results of Operations Issues

45.1. Development of the CPUC-Jurisdictional Revenue Requirement

The operating expenses and investment-related costs that SCE presents in this GRC also include base-related FERC-jurisdictional transmission-related operating and capital costs, which are recovered through rates authorized by the

¹⁷⁶⁰ Cal Advocates RB at 9.

¹⁷⁶¹ D.19-05-020 at 358.

¹⁷⁶² *Id.* at 437, OP 5.a.

FERC.¹⁷⁶³ In order to determine the CPUC-jurisdictional revenue requirement to be recovered through CPUC-authorized rates, SCE uses a Commission-approved methodology to calculate factors to allocate total company costs between CPUC and FERC jurisdiction. SCE presents those allocation factors in Ex. SCE-07, Vol. 1A2 at Table IV-8. Cal Advocates has reviewed SCE's testimony, workpapers, calculations, and data responses and does not oppose the jurisdictional allocation factors used by SCE.¹⁷⁶⁴ We adopt SCE's uncontested jurisdictional allocation factors.

45.2. Cost Escalation

SCE uses a variety of escalation rates to estimate the effects of inflation on its labor, non-labor, and capital costs. SCE uses these escalation rates to deflate recorded O&M and Administrative and General (A&G) expenses from 2014-2018 and inflate forecast O&M and A&G expenses for 2019-2023.

With respect to labor escalation, SCE's recorded (2014-2018) labor cost escalation is based on calculating actual annual average hourly earnings at the employee level across the company.¹⁷⁶⁵ SCE's forecast (2019-2023) labor costs are based on: collective bargaining agreements and IHS Markit Power Planner forecasts of labor escalation rates for U.S. electric utilities.¹⁷⁶⁶

For recorded and forecast non-labor escalation, SCE uses indexes provided by the IHS Markit Power Planner publication.¹⁷⁶⁷ Power Planner provides

¹⁷⁶³ Unless otherwise specified, all the forecasts presented in this decision are on a total company basis.

¹⁷⁶⁴ Cal Advocates OB at 299.

¹⁷⁶⁵ Ex. SCE-07, Vol. 1A2 at 88.

¹⁷⁶⁶ *Id.* at 88-90.

¹⁷⁶⁷ *Id.* at 90.

indexes of O&M combined materials and services costs by the functional O&M categories of steam, nuclear, hydro, other power production, transmission, distribution, customer accounts customer service information, and administrative and general (without healthcare).

To escalate costs for Palo Verde, SCE blends non-labor escalation and labor escalation by weighting and escalating the labor and non-labor costs.¹⁷⁶⁸

SCE's capital escalation rates, except for General Plant, are based on the IHS Markit forecasts of the Handy-Whitman Index of Public Utility Construction Costs.¹⁷⁶⁹ SCE's General Plant capital escalation is based on an index built by SCE, which SCE developed by assigning the General Plant cost categories the appropriate IHS Markit variables weighted by recorded General Plant costs for 2018.¹⁷⁷⁰

SCE provided updated escalation rates to reflect the most current inflationary environment during the update phase of this proceeding.¹⁷⁷¹ Unless otherwise specified,¹⁷⁷² we adopt SCE's proposed escalation rates for labor, non-labor, and capital costs for 2014-2021. Escalation of costs for 2022 and 2023 is addressed in Post-Test Year Ratemaking (Section 46).

45.3. Overhead Allocation

45.3.1. Capitalized A&G Expense

SCE estimates a capitalization rate of 28.0 percent for Administrative and General (A&G) expenses based on its A&G Effort Study examining costs that are

¹⁷⁶⁸ *Id.* at 90-91.

¹⁷⁶⁹ *Id.* at 92.

¹⁷⁷⁰ *Ibid.*

¹⁷⁷¹ Ex. SCE-52A2E2 at 8-12.

¹⁷⁷² *See, e.g.,* Decommissioning Escalation (Section 43.4).

not already directly recorded to capital work orders.¹⁷⁷³ SCE applies this rate to applicable A&G expenses in Account 920 (A&G Salaries) and Account 921 (Office Supplies and Expenses). We approve SCE's uncontested A&G capitalization rate.

45.3.2. Capitalized P&B Expense

SCE estimates a capitalization rate of 50.0 percent for Pension and Benefit (P&B) expenses, which SCE calculates by dividing the total 2018 recorded wages paid for construction by the total recorded wages paid by SCE (excluding below-the-line wages).¹⁷⁷⁴ SCE applies this rate to applicable P&B expenses in Account 925 (Injuries and Damages) and Account 926 (Employee P&B). We approve SCE's uncontested P&B capitalization rate.

46. Post-Test Year Ratemaking (PTYR)

46.1. SCE's Proposals

SCE requests a PTYR mechanism to adjust the revenue requirement in 2022 and 2023. For O&M, SCE proposes to continue using the escalation rate methodology adopted by the Commission in its last three GRCs. For capital, SCE proposes to use its Board-reviewed capital budget, bifurcated between wildfire and non-wildfire capital additions. According to SCE's update testimony, SCE's proposed PTYR mechanism would result in increases of \$452.0 million (or 5.9 percent) in 2022 and \$524.1 million (or 6.5 percent) in 2023.¹⁷⁷⁵ SCE states that its proposal is designed to allow SCE to adequately serve its customers and give SCE the opportunity to recover the costs associated with serving customers,

¹⁷⁷³ Ex. SCE-07, Vol. 1A2 at 124.

¹⁷⁷⁴ *Id.* at 125.

¹⁷⁷⁵ Ex. SCE-52A2E2 at 2.

including earning a reasonable return for its investors.¹⁷⁷⁶ SCE's specific proposals are discussed below.

46.1.1. O&M Escalation

SCE proposes to escalate O&M expenses using the same utility-specific price indexes it uses to escalate its O&M expenses from the recorded year 2018 to the TY 2021, and which the Commission has adopted for O&M escalation in SCE's last three GRCs.¹⁷⁷⁷ For non-labor costs, SCE proposes to use the latest IHS Markit (formerly known as Global Insight) escalation rates available on November 1 of the year in which the attrition advice letter filings are made. For labor expenses, SCE proposes to incorporate known labor cost increases at the time of the GRC decision. SCE also proposes using various escalation factors for other employee benefit costs as follows:¹⁷⁷⁸

Category	2022	2023	Comments
Medical Programs	5.00%	5.00%	Medical cost escalation rate
Dental Programs	3.00%	3.00%	Dental escalation rate
Vision Service Plan	3.00%	3.00%	VSP escalation rate
Disability Programs	3.07%	2.91%	Labor escalation rate
Group Life Insurance	0.00%	0.00%	Group life insurance trend rate
Misc. Benefit Programs	2.18%	2.14%	A&G nonlabor escalation rate
Executive Benefits	3.07%	2.91%	Labor escalation rate
401(k)	3.07%	2.91%	Labor escalation rate

46.1.2. Capital Cost Increases

For capital, SCE proposes a budget-based forecast which separates wildfire and non-wildfire related capital additions. AB 1054 requires the exclusion of the first \$1.575 billion of SCE's wildfire mitigation plan fire risk mitigation capital

¹⁷⁷⁶ SCE OB at 389.

¹⁷⁷⁷ Ex. SCE-07, Vol. 4A at 28-30; Ex. SCE-18, Vol. 4 at 20.

¹⁷⁷⁸ Ex. SCE-07, Vol. 4A at 30, Table III-4.

expenditures after the statute's effective date from earning an equity return.¹⁷⁷⁹ SCE states that its proposal for budgeted capital additions and bifurcation are necessitated by AB 1054, which leads to minimal wildfire capital additions in the test year followed by a significant increase in wildfire capital additions in the post-test years when SCE's wildfire capital additions exceed the excluded amount and again become eligible for a full equity return. SCE's total proposed capital additions are as follows:¹⁷⁸⁰

Proposed Capital Additions (\$ millions)			
	2021	2022	2023
Non-Wildfire	3,123.9	3,186.7	3,150.3
Wildfire Risk Mitigation	222.9	752.6	1,076.9
AB 1054 Capital Exclusions	553.6	150.4	0

46.1.3. Annual Advice Letter

SCE proposes to submit its 2022 and 2023 attrition requests via advice letter by December 1 of the prior year. The advice letter would specify the revenue requirement adjustment for O&M escalation and changes in capital-related costs. In the Q4 2022 advice letter submittal, there will be no true-up to the 2022 authorized level of O&M expense resulting from the incorporation of actual escalation in the first part of 2022.¹⁷⁸¹

46.1.4. Treatment of Major Exogenous Cost Changes

SCE proposes to continue the existing Z-Factor mechanism, which allows SCE to seek to recover costs associated with exogenous events that result in a

¹⁷⁷⁹ *Id.* at 31 citing Pub. Util. Code, § 8386.3(e).

¹⁷⁸⁰ *Id.* at 32, Table III-5 and 34, Table III-10.

¹⁷⁸¹ *Id.* at 29.

major cost impact for SCE.¹⁷⁸² Under the current mechanism, either SCE or Cal Advocates may submit a letter of notification to the Executive Director to identify any Z-Factor event. SCE is responsible for any events that do not have a financial impact of more than \$10 million. There is a \$10 million “deductible amount” applied on a one-time basis to the first year’s revenue requirement associated with any approved Z-Factors.

46.2. Cal Advocates’ Proposals

Cal Advocates does not oppose a PTYR mechanism which will provide SCE some reasonable level of revenue increases in 2022 and 2023 but opposes SCE’s requested increases of 6.0 percent for 2022 and 6.5 percent for 2023. Cal Advocates argues that utilities are not automatically entitled to attrition rate increases between rate cases and that SCE’s requested increases are beyond the range of recently authorized attrition increases in the GRCs for the large California energy utilities.

Cal Advocates recommends lower post-test year base revenue increases of \$242.8 million (or 3.5 percent) in 2022 and \$251.3 million (or 3.5 percent) in 2023. Cal Advocates’ recommendation is based on application of the Consumer Price Index-Urban (CPI-U) forecasts for 2022-2023 plus a premium.¹⁷⁸³ IHS Markit forecasts CPI-U of 2.2 percent for 2022 and 2.5 percent for 2023.¹⁷⁸⁴

Alternatively, Cal Advocates recommends the Commission adopt SCE’s proposed methodology for escalating O&M expenses and escalate TY capital additions by 2.3 percent for 2022 and 2.3 percent for 2023.¹⁷⁸⁵ Cal Advocates

¹⁷⁸² *Id.* at 34-35.

¹⁷⁸³ Cal Advocates OB at 310.

¹⁷⁸⁴ IHS Markit, US Economic Outlook, February 2020 at 72 found at Ex. PAO-17-WP at 101.

¹⁷⁸⁵ Cal Advocates OB at 314-315.

opposes SCE's budget-based plant addition estimates for 2022 and 2023. Cal Advocates states it has reviewed 2019-2021 capital additions, but it has not evaluated, and does not plan on reviewing proposed 2022 and 2023 capital expenditure forecasts. Cal Advocates argues there is no guarantee SCE will follow through with the capital additions levels as proposed. Cal Advocates further argues the Commission rejected a similar proposal in the previous GRC.

Cal Advocates does not oppose SCE's proposed procedure for requesting attrition adjustments for 2022 and 2023 via advice letter.¹⁷⁸⁶ Cal Advocates also does not oppose continuation of the Z-Factor mechanism, but recommends it apply to decreases as well as increases in costs.¹⁷⁸⁷

46.3. TURN's Proposals

TURN recommends that the Commission adopt a two-part PTYR mechanism that separately escalates O&M expenses and capital-related costs.

TURN recommends that the Commission escalate O&M expenses at the CPI-U (estimated to be 2.3 percent for 2022 and 2.5 percent for 2023) or in the alternative, escalate O&M expenses at the CPI-U plus 50 basis points (estimated to be 2.8 percent for 2022 and 3.0 percent for 2023).¹⁷⁸⁸

TURN recommends that capital-related costs be based on a two-part approach that separately determines wildfire mitigation capital additions and non-wildfire related capital additions. TURN recommends that wildfire mitigation capital additions be based on a specific capital budget adopted for the test year and each attrition year.¹⁷⁸⁹ TURN recommends that non-wildfire

¹⁷⁸⁶ *Id.* at 311.

¹⁷⁸⁷ *Id.* at 311-312.

¹⁷⁸⁸ Ex. TURN-07 at 16, 18.

¹⁷⁸⁹ TURN OB at 344-345.

related capital additions (with the exception of Residential New Customer Connections and Commercial New Customer Connections) be based on the adopted non-wildfire related capital additions for the test year with zero escalation in each of the attrition years.¹⁷⁹⁰ TURN proposes specific 2022 and 2023 budgets for Residential New Customer Connections and Commercial New Customer Connections.¹⁷⁹¹

TURN's primary proposal would result in increases of 4.9 percent for 2022 and 4.8 percent for 2023. TURN's alternative proposal would result in increases of 5.1 percent for 2022 and 4.9 percent for 2023.¹⁷⁹²

46.4. Discussion

Under the Energy Rate Case Plan, applicants may request an attrition allowance as part of their application for the test year revenue requirement.¹⁷⁹³ The Commission has made clear that it has the discretion to grant or deny such requests and that utilities are not automatically entitled to an attrition mechanism between rate cases.¹⁷⁹⁴

We find it reasonable to authorize a PTYR mechanism during this GRC cycle in order to give SCE an opportunity to offset some inflationary price increases and to recover costs for capital investments, particularly investments for wildfire risk mitigation, which are necessary for SCE to continue to provide safe and reliable service. Since O&M expenses and capital costs affect revenue

¹⁷⁹⁰ *Id.* at 346-347.

¹⁷⁹¹ Ex. TURN-07 at 10; Ex. TURN-02 at 45-60.

¹⁷⁹² TURN OB at 333.

¹⁷⁹³ D.07-07-004, Attachment A at A-19

¹⁷⁹⁴ *See, e.g.*, D.19-05-020 at 280; D.17-05-013 at 132-133 quoting D.93-12-043, 52 CPUC2d 471, 492.

requirement differently, we adopt a two-part mechanism that separately escalates O&M expenses and capital-related costs. In addition, given the large amount of wildfire capital additions that will be excluded in the test year due to AB 1054, we further bifurcate treatment of wildfire capital additions and non-wildfire capital additions.

With respect to O&M expenses, consistent with our determination in nearly every SCE GRC since 2003,¹⁷⁹⁵ we approve use of the utility-specific indices proposed by SCE because they more accurately reflect how utilities incur costs. Both Cal Advocates and TURN offer proposals which are based on CPI-U or CPI-U plus a premium. As we have previously explained, the CPI reflects consumer retail price changes and does not reflect how utilities incur costs.¹⁷⁹⁶ Moreover, neither Cal Advocates nor TURN offer a reasoned basis for the premiums they propose to add to the CPI-U.

With respect to capital additions, given AB 1054's unique impacts on wildfire mitigation capital additions during this GRC cycle, we agree with SCE and TURN that it is appropriate to separately consider SCE's wildfire mitigation capital additions and non-wildfire capital additions.

We find it reasonable to adopt a budget-based forecast for wildfire mitigation capital additions.¹⁷⁹⁷ As described above, AB 1054 requires the exclusion of \$1.575 billion of SCE's wildfire-related capital additions from

¹⁷⁹⁵ The sole exception is the 2009 GRC. (See Ex. SCE-07, Vol. 4A at 27, Table III-3.)

¹⁷⁹⁶ D.15-11-021 at 391; D.14-08-032 at 653.

¹⁷⁹⁷ The wildfire-related capital activities consist of the following: HFRA Sectionalizing Devices, Distribution Fault Anticipation, Enhanced Overhead Inspections and Remediations, Enhanced Situational Awareness, Fire Science and Advanced Modeling, Fusing Mitigation, PSPS Execution, Undergrounding, and the Wildfire Covered Conductor Program. (Ex. SCE-04, Vol. 5E at 6, Table I-2.)

earning an equity return. The AB 1054 exclusion results in \$399 million of SCE's wildfire capital additions being excluded from the TY forecast.¹⁷⁹⁸ An attrition year revenue requirement based on escalation of the TY forecast, as proposed by Cal Advocates, would not provide SCE with adequate funding in the post test-years for necessary investments in wildfire risk mitigation. Although Cal Advocates did not review the 2022 and 2023 capital expenditure forecasts, these issues were vigorously litigated and there is a robust record on these issues due to TURN's analysis and alternative recommendations. The specific budgets are addressed in the Wildfire Management Section (Section 17).

We reject SCE's proposal to adopt a budget-based forecast for non-wildfire related capital additions that are not impacted by the AB 1054 exclusion with the exception of the Residential and Commercial New Service Connections forecasts. As recognized by SCE, in recent GRCs, the Commission has rejected SCE's requests to use budget-based capital addition forecasts in its PTYR mechanism.¹⁷⁹⁹ The Commission has previously explained that an attrition rate adjustment "is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [a] rate of return."¹⁸⁰⁰ The Commission has also explained:

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. In addition, no party other than SCE provided or analyzed detailed post-TY plant addition

¹⁷⁹⁸ The AB 1054 exclusion amount for the TY is derived from the RO model and is less than initially forecast by SCE due to a higher exclusion amount being applied to 2019 due to higher recorded capital expenditures in that year.

¹⁷⁹⁹ SCE OB at 393.

¹⁸⁰⁰ TURN OB at 336-337 quoting D.14-08-032 at 652.

forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR budgets... [it] imposes a significant burden on resources.¹⁸⁰¹

We decline to adopt a budget-based forecast for most of SCE's non-wildfire capital additions in this GRC for the same reasons. TURN notes that SCE's proposed non-wildfire mitigation capital expenditures address 415 Work Breakdown Structure categories, which fall into approximately 120 activity areas.¹⁸⁰² With the exception of the Residential and Commercial New Service Connections forecasts, which were reviewed by TURN, no party reviewed or analyzed SCE's non-wildfire capital budgets for 2022 and 2023.

The new service connection forecasts comprise the largest areas of non-wildfire capital spending proposed by SCE in this GRC.¹⁸⁰³ Given that there are alternative budgets and a robust record on these issues for the Commission to consider, we find it appropriate to adopt 2022 and 2023 budgets for these activities. The specific budgets are addressed in the New Service Connections Section (Section 14.1).

With respect to the remainder of SCE's non-wildfire related capital additions, TURN recommends zero escalation of these capital additions in the attrition years given the increase in wildfire capital additions during this rate case cycle and the serious economic conditions facing ratepayers.¹⁸⁰⁴ In order to help mitigate the impacts of large wildfire capital additions in the post-test years,

¹⁸⁰¹ D.12-11-051 at 606 quoting D.09-03-025.

¹⁸⁰² TURN OB at 345.

¹⁸⁰³ *Id.* at 346, Figure 41-2.

¹⁸⁰⁴ *Id.* at 347-348. SCE's budget-based proposals for non-wildfire capital additions excluding new service connections would result in increases of 2.0 percent in 2022 and 1.3 percent in 2023. (Ex. SCE-18, Vol. 4 at 29, Table II-3.)

and given the uncertainty in SCE's actual spending in these years and the economic uncertainty facing ratepayers due to the COVID-19 pandemic, we find reasonable and adopt TURN's recommendation to adopt zero escalation for the remainder of SCE's non-wildfire related capital additions.

SCE's unopposed request to submit its annual attrition request via advice letter is approved. The revenue requirement and percentage change for each attrition year will depend on the final adopted TY revenue requirement and updates to the various escalation factors as set forth in SCE's proposal.

SCE's unopposed request to continue the Z-Factor mechanism is also approved. As noted by SCE, the Z-Factor mechanism encompasses changes that can either increase or decrease costs.¹⁸⁰⁵

47. Compliance Requirements

In Exhibits SCE-08 and SCE-08-E, SCE submitted a list of compliance action items that impact the 2021 GRC. SCE's list identifies the Commission decision or Public Utilities Code Section that gave rise to the compliance item, the action required, and the compliance action taken. No party challenged or expressed any concerns with SCE's compliance requirements showing. Cal Advocates has verified that SCE's compliance action items addressed the items the Commission ordered and makes no further recommendations.¹⁸⁰⁶ We have reviewed SCE's compliance showing and find that SCE has adequately demonstrated compliance with the items listed in its compliance exhibit.

¹⁸⁰⁵ *Id.* at 34-35 citing Preliminary Statement AAA, Sheet 3; D.94-06-011 at 77, fn. 78; D.89-10-031 at 138.

¹⁸⁰⁶ Cal Advocates OB at 316.

48. Accessibility Issues

SCE and the Center for Accessible Technology (CforAT) jointly submitted a proposal addressing accessibility issues for SCE's customers with disabilities (Joint Proposal).¹⁸⁰⁷ The Joint Proposal calls for SCE to spend or incur \$1.0 million on average per year over the 2021 GRC cycle for activities supporting and enhancing the accessibility of SCE's facilities, programs, communications, and services for customers with disabilities. The proposed spending is based on historical spending from prior years and is embedded in the forecasts of related activities from each of the impacted Operating Units.

The Joint Proposal includes the following elements:¹⁸⁰⁸

- Annual reporting and consultation with CforAT on accessibility improvement activities and related spending;
- Continuation of a designated Accessibility Coordinator responsible for coordinating and managing SCE's Disability Rights Compliance Program; and
- Survey and repair/remediation of accessibility issues concerning Transaction-Related Elements at Authorized Payment Agencies, service centers open to the public, web content at www.sce.com, alternative formats of customer communication materials for blind and visually impaired customers, and pedestrian traffic control near temporary construction sites.

No party contested the Joint Proposal. The Joint Proposal builds off similar proposals adopted in prior GRCs and the proposed spending is in line with previously authorized amounts. We find reasonable and approve the Joint Proposal. If SCE seeks to continue this program in the next GRC, SCE should include as supporting documentation the annual reports prepared during this

¹⁸⁰⁷ Ex. SCE-09.

¹⁸⁰⁸ *Id.* at 2-4.

GRC cycle so that the Commission can better assess the accomplishments of the program and whether the spending is incremental and not duplicative of other approved funding.

49. Results of Financial Examination by Cal Advocates

Cal Advocates conducted an examination of SCE's financial and accounting records of O&M expenses, A&G expenses, and capital expenditures.¹⁸⁰⁹ The scope of this examination covered 2014 to 2018 and focused on SCE's compliance with Commission-established rules and regulations, and the ratemaking effects of SCE's proposed revenue requirement. Based on this examination, Cal Advocates recommends the following adjustments:¹⁸¹⁰

- (1) A reduction to SCE's recorded Audit labor expenses for 2016-2018. This issue is addressed in Audit Services (Section 33).
- (2) A reduction to SCE's recorded 2018 A&G non-labor expenses for the GRC Activity Develop and Manage Policy and Initiatives. This issue is addressed in Section 37.1.
- (3) The transfer of \$30,823,607 from recorded 2018 O&M expenses for vegetation management to the Fire Hazard Prevention Memorandum Account (FHPMA). SCE explains that the purpose of including the FHPMA-eligible costs in the recorded 2018 data was to inform the 2021 TY forecast, not to seek recovery of these costs in this track of the proceeding.¹⁸¹¹ The Vegetation Management Program O&M forecast is discussed in Section 16.
- (4) A \$567,159 reduction to SCE's recorded 2018 O&M non-labor expenses for Grid Modernization - T&D Deployment Readiness because the costs were identified as a one-time

¹⁸⁰⁹ Ex. PAO-18 contains Cal Advocates' Financial Examination Report.

¹⁸¹⁰ Cal Advocates OB at 317.

¹⁸¹¹ Ex. SCE-21 at 1.

cost. Cal Advocates' recommendation does not impact SCE's proposed TY forecast for this activity because SCE did not use 2018 recorded costs to develop its forecast. SCE's forecast for T&D Deployment Readiness is discussed in Section 12.1.1.1.

(5) A \$31,150 reduction to SCE's recorded 2018 O&M non-labor expenses for Technology Assessment, which SCE incorrectly recorded as O&M instead of capital. SCE does not dispute that it incorrectly charged costs related to hybrid poles as O&M rather than capital but states that the amount inadvertently charged was \$93,420.¹⁸¹² In rebuttal testimony, SCE excluded this amount from its 2018 recorded expenses for purposes of determining its 2021 forecast, which is based on a five-year historical average.¹⁸¹³ This forecast is discussed in Grid Technology O&M (Section 12.2.2).

(6) Cal Advocates does not make any recommended adjustments to recorded capital expenditures.

50. SDG&E Request for SONGS-Related Cost Recovery

SDG&E owns a 20 percent interest in San Onofre Nuclear Generating Station (SONGS) and is responsible for 20 percent of SONGS-related expenses. SCE bills SDG&E for SDG&E's proportionate share of costs incurred by SCE, plus any applicable overheads. In the past, the Commission has addressed SDG&E's recovery of these costs in SCE's GRCs.¹⁸¹⁴

In this GRC, SDG&E requests cost recovery for its 20 percent co-owner's share of Marine Mitigation projects and SONGS-related Workers' Compensation costs, which are ineligible to be paid from nuclear decommissioning trust

¹⁸¹² *Id.* at 6.

¹⁸¹³ *Ibid.*; Ex. SCE-13, Vol. 4, Pt. 1 at 76, fn. 229.

¹⁸¹⁴ See D.04-07-022 at 324, FOF 43 ("To ensure consistent treatment of SONGS expenditures and to avoid duplicate litigation, the Commission has addressed SONGS-related expenses that SCE bills to SDG&E in SCE's GRCs.").

funds.¹⁸¹⁵ SDG&E initially forecast a 2021 SONGS revenue requirement of \$1.545 million based on costs of \$1.309 million for Marine Mitigation (including contractual overheads) and \$0.180 million for Workers' Compensation, and application of the authorized Franchise Fees and Uncollectibles (FF&U) (3.745 percent) rate from SDG&E's TY 2019 GRC.¹⁸¹⁶ In comments on the proposed decision, SDG&E adjusts its 2021 forecast to \$1.517 million based on the updated escalation rates in SCE's update testimony.¹⁸¹⁷

SDG&E's request for cost recovery is unopposed. We find reasonable and approve SDG&E's methodology for calculating its 20 percent share of SONGS-related costs and resulting 2021 forecast SONGS revenue requirement. SCE shall make any necessary adjustments to its 2021 SONGS revenue requirement in accordance with the costs and escalation rates we adopt for SCE in this decision. SDG&E shall also update its SONGS revenue requirement for 2022 and 2023 based on the approved costs for SCE, and SDG&E's authorized FF&U rate, and consistent with current practice, shall file an annual advice letter reflecting the updates.

51. GRC Update Phase

The Commission's Rate Case Plan allows for certain limited, known cost changes to be reflected through update testimony.¹⁸¹⁸ SCE's update testimony

¹⁸¹⁵ SCE's O&M forecasts for Marine Mitigation and Workers' Compensation are addressed in Sections 32.1 and 28.2, respectively.

SDG&E records the Marine Mitigation costs in its Marine Mitigation Memorandum Account and the Workers' Compensation costs in its SONGS Balancing Account. (SDG&E OB at 8.)

¹⁸¹⁶ *Id.* at 6-7.

¹⁸¹⁷ SDG&E/SoCalGas PD Opening Comments at 3.

¹⁸¹⁸ Including known changes in cost of labor, changes in non-labor escalation factors based on the same indexes used in the original presentation, and known changes based on governmental action. (See D.89-10-040, Appendix B at B-26.)

includes a revised TY O&M forecast of Postage Expense;¹⁸¹⁹ revised cost escalation rates to reflect the most current inflationary environment and economic impacts of COVID-19;¹⁸²⁰ the removal of expenses incurred in assisting or deterring union organizing, as required by AB 560 (Stats. 2019); updates to SCE's forecasts for the Integrated Distributed Energy Resources Administrative Costs Memorandum Account (IDERACMA) and Distribution Deferral Administration Costs Memorandum Account (DDACMA);¹⁸²¹ the new cost of capital adopted in D.19-12-056; Hydro Decommissioning concessions and RO Model corrections that SCE addresses in other sections of testimony; and corrections to SCE's property tax forecast.¹⁸²² SCE's update testimony also includes a revised TY O&M forecast for vegetation management programs to address SB 247, which we address in Section 16, and updated escalation rates for SCE's requested PTYR mechanism to adjust the revenue requirement in 2022 and 2023, which we address in Section 46. Excluding the updated forecast for vegetation management programs to address SB 247, SCE's GRC update filing results in a net decrease to the 2021 revenue requirement by \$30.26 million as compared to SCE's prior request.¹⁸²³

¹⁸¹⁹ Reflecting the postage rate increase approved by the Postal Regulatory Commission on December 6, 2019. (Ex. SCE-52A2E2 at 15.)

¹⁸²⁰ Based on the IHS Markit Power Planner projection for the first quarter of 2020. (*Id.* at 8.)

¹⁸²¹ The IDERACMA and DDACMA accounts track costs for activities related to D.16-12-036, which requires participating utilities to establish accounts to record and track various costs incurred for an incentive pilot to deploy DERs that displace or defer the need for capital expenditures on traditional distribution infrastructure. (Ex. SCE-07, Vol. 1A2 at 37-39.)

¹⁸²² Ex. SCE-52A2E2 at 2-18.

¹⁸²³ This amount does not include SCE's updated request for Vegetation Management (\$111.178 million), which we address in Section 16. (*Id.* at 2, Table I-1.)

Apart from SCE's updates to its forecast for vegetation management and its request for a PTYR mechanism (addressed in Sections 16 and 46, respectively), SCE's update testimony is uncontested. We find the uncontested portions of SCE's update testimony to be reasonable, consistent with the limited cost changes appropriate for update testimony, and in ratepayers' best interest. Therefore, these updates are approved and are reflected in the final approval amounts throughout this decision.

52. Settlements

52.1. Solar Photovoltaic Data and Analysis

On September 9, 2020, SCE and SEIA/Vote Solar filed a motion for the adoption of a settlement agreement (SCE and SEIA/Vote Solar Joint Motion). No other party commented on the motion or settlement agreement. In the settlement, the parties agree to collaborate on a variety of issues related to the development of future solar photovoltaic (PV) data and analysis. Some specific commitments include:¹⁸²⁴

- (1) Enhancements to SCE's PV Dependability¹⁸²⁵ methodology, including the investigation of potential data anomalies, used by SCE in connection with the 2021 Distribution Planning Process.
- (2) An analysis of certain DER project cancellations with internal forecast costs that exceed \$10 million.
- (3) An agreement that SCE will provide to SEIA/Vote Solar both the PV Dependability Enhancement Data and the Project Cancellation Data in August of 2021, 2022, and 2023.

¹⁸²⁴ SCE and SEIA/Vote Solar Joint Motion at 4-5.

¹⁸²⁵ PV Dependability means the amount of solar PV system generation that is considered dependable and can be relied upon for reliability planning purposes in SCE's Distribution Planning Process. (See SCE and SEIA/Vote Solar Joint Motion at 4, fn. 3.)

In their joint motion, SCE and SEIA/Vote Solar assert that the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.¹⁸²⁶ We agree the settlement meets the requirements of Rule 12.1(d). SEIA/Vote Solar's litigation position in this proceeding included several recommendations for enhancements to SCE's PV Dependability methodology, as well as support for Cal Advocates' recommendations pertaining to Grid Modernization activities.¹⁸²⁷ The settlement appears to represent a reasonable resolution of SEIA/Vote Solar's recommendations regarding the load growth-offsetting capabilities of solar PV. The process for conducting the settlement was made in accordance with Article 12 of the Commission's Rules of Practice and Procedure, and we are unaware of any inconsistency with the Public Utilities Code, Commission decisions, or the law in general. Lastly, the settlement fairly represents the affected interests at stake in this proceeding, providing a compromise between SCE's and SEIA/Vote Solar's litigation positions in a prudent and efficient manner. The settlement also puts in place procedures to encourage greater ongoing collaboration between the parties. Therefore, we approve the settlement between SCE and SEIA/Vote Solar.

52.2. Other Operating Revenue – Community Choice Aggregation Fees

On September 10, 2020, SCE and the SoCal CCAs filed a motion for adoption of a settlement agreement (SCE and SoCal CCAs Joint Motion). No other party commented on the motion or settlement agreement. In the settlement, the parties agree to certain CCA-related fee modifications, as well as

¹⁸²⁶ SCE and SEIA/Vote Solar Joint Motion at 6-9.

¹⁸²⁷ Ex. SVS-01 at 3-5.

the provision of additional data and ongoing process improvements. Some specific terms of the settlement agreement include:¹⁸²⁸

- (1) CCA-related Service Fee Modifications: (1) The Mass Enrollment – Per Service Account fee will be modified from SCE’s initially proposed \$0.16 to \$0.48; (2) the CCA Termination of Service - Voluntary Termination per Event, per Service Account fee will be modified from SCE’s initially proposed \$0.08 to \$0.40; (3) the Meter and Data Management Agent (MDMA) – Meter Dating Posting Fee will be modified from SCE’s initially proposed \$0.08 to \$0.04 (note: in rebuttal testimony, SCE’s reduced its requested MDMA fee to \$0.04)¹⁸²⁹; (4) the Standard Phase-In Service – Per Service Account fee will be modified from SCE’s initially proposed \$0.16 to \$0.48; and (5) the Monthly Account Maintenance Fee (MAMF) – Per Service Account will be modified from SCE’s initially proposed \$0.06 to \$0.04.¹⁸³⁰
- (2) Additional Provisions Related to the MAMF: SCE commits to develop and provide additional data and analysis regarding the basis for the MAMF.
- (3) Automation Efforts and Process Improvements: SCE commits to investigate, and potentially implement, processes to reduce manual work and service fees generally, and to reduce or eliminate the EDI-VAN charge.¹⁸³¹
- (4) Additional Data and Advanced Metering Infrastructure (AMI) Data: SCE commits to provide the “allcity” or “all-customer” lists within a respective CCA’s service territory once per month (Additional Data), and will

¹⁸²⁸ Joint Motion with SoCal CCAs at 4-7.

¹⁸²⁹ Ex. SCE-14 at 84.

¹⁸³⁰ Ex. SCE-03, Vol. 6AE at 39E, Table V-23; SCE and SoCal CCAs Joint Motion at 4-5.

¹⁸³¹ SCE’s EDI-VAN fee relates to SCE’s cost to transmit data in Electronic Data Interchange (EDI) formatting through the Value-Added Network (VAN). (See SCE and SoCal CCAs Joint Motion, at 5, fn. 4.)

receive and consider a request from the SoCal CCAs to provide AMI Data on a more regular and timely basis to support CCA functions.

In their joint motion, SCE and the SoCal CCAs assert that the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.¹⁸³²

We agree the settlement meets the requirements of Rule 12.1(d). In testimony, the SoCal CCAs recommended various adjustments to SCE's proposed CCA service and opt-out fees for a TY OOR of \$2.417 million for CCA activities, or a \$1.466 million reduction from SCE's initial request.¹⁸³³ The SoCal CCAs also provided various other recommendations concerning access to CCA customer usage data, SCE's manual process for opt-outs, and general improvements to perceived inefficiencies and data-related interactions.¹⁸³⁴ In rebuttal, SCE proposed a TY OOR of \$3.714 million for CCA activities, noting that this amount included a number of corrections SCE made in the calculation of the MAMF fee.¹⁸³⁵ The settlement, if approved, would result in a TY OOR of \$2.787 million for CCA activities.¹⁸³⁶ We find the settlement agreement strikes an appropriate balance between the parties' positions, and is well within a reasonable range of litigated outcomes.

The process for conducting the settlement was also made in accordance with Article 12 of the Commission's Rules of Practice and Procedure, and we are unaware of any inconsistency with the Public Utilities Code, Commission

¹⁸³² SCE and SoCal CCAs Joint Motion at 7-12.

¹⁸³³ Ex. SCE-14 at 80, Table VI-19.

¹⁸³⁴ Ex. SoCal CCAs-01 at 4-5.

¹⁸³⁵ *Id.* at 80 and 85-94.

¹⁸³⁶ SCE OB at 186.

decisions, or the law in general. Lastly, settlement fairly represents the affected interests at stake in this proceeding, providing a compromise between SCE's and the SoCal CCAs litigation positions in a prudent and efficient manner.

Therefore, we approve the settlement agreement between SCE and the SoCal CCAs.

52.3. Other Operating Revenue – Pole Attachment Fees

On September 9, 2020, SCE and Conterra filed a motion for adoption of a settlement agreement (Joint Motion with Conterra). No other party commented on the motion or settlement agreement. As part of the settlement, Conterra has agreed to refrain from further litigation in this GRC in exchange for discrete adjustments to certain attachment fees and a one-time reduction to invoices SCE has previously issued to Conterra. Some of the specific terms of the settlement are as follows:¹⁸³⁷

- (1) SCE will reduce the amount that Conterra owes SCE pursuant to invoices through a one-time reduction totaling \$80,968.00.
- (2) On a going-forward basis, Conterra will not be required to submit pole loading calculations with its application to attach telecommunication apparatus to SCE poles.
- (3) SCE's Processing and Engineering Fee for Conterra will be \$186.78, and SCE's Post-Attachment Inspection Fee for Conterra will be \$215.67. These fees will remain unchanged at least until December 31, 2024.

In their joint motion, SCE and Conterra assert that the settlement is reasonable in light of the whole record, consistent with the law, and in the public

¹⁸³⁷ SCE and Conterra Joint Motion at 4.

interest.¹⁸³⁸ While the Commission has a long-standing public policy favoring the settlement of disputes if they are fair and reasonable in light of the whole record,¹⁸³⁹ we are not convinced the proposed settlement agreement meets the requirements of Rule 12.1(d): first, there is nothing in the record pertaining to the potential safety or cost implications that could result from Conterra being allowed to forego the submission of pole loading calculations.¹⁸⁴⁰ Second, the settlement agreement does not specify who will pay for the one-time reduction to Conterra's outstanding invoices. To the extent these costs would be borne by ratepayers, we do not find the settlement to be in the public interest. Finally, while Commission allows telecommunications carriers some flexibility to negotiate their own pole attachment pricing agreements,¹⁸⁴¹ the settlement appears to contemplate complete forgiveness of outstanding SCE post-attachment inspection invoices,¹⁸⁴² which runs contrary to the requirement that a utility be reimbursed for actual expenses incurred.¹⁸⁴³ For all these reasons we reject the proposed settlement between SCE and Conterra.

On September 8, 2020, Conterra filed a motion to admit into evidence the public and confidential versions of its direct testimony in this proceeding. The motion was granted via the ALJs' email ruling on September 28, 2020. SCE's

¹⁸³⁸ *Id.* at 5-8.

¹⁸³⁹ See D.88-12-083 (30 CPUC 2d 189, 221-223); D.91-05-029 (40 CPUC 2d 301, 326); and D.05-03-022 at 8-9.

¹⁸⁴⁰ In rebuttal testimony, SCE does indicate that a Third-Party Attachment team reviews pending attachment applications for pole loading (*See Ex. SCE-13, Vol. 7 at 10*). However, there is no discussion concerning how pole loading calculations submitted by the applicant are used in the application review process.

¹⁸⁴¹ D.98-10-058 at 51.

¹⁸⁴² SCE and Conterra Joint Motion at 4; Ex. Conterra-02 at 8.

¹⁸⁴³ *Id.* at 50.

testimony concerning pole attachment fees and SCE's OOR forecast has also been admitted into the evidentiary record of this proceeding.¹⁸⁴⁴ We find there is sufficient record evidence to resolve all disputed issues between SCE and Conterra and make a final determination on the OOR forecast for pole attachments. We address SCE's and Conterra's litigation positions on these issues in Section 18.2 (T&D OOR).

53. Motions

All previous rulings made during this proceeding are affirmed. In addition, the following unopposed motions are granted:

- The Motion of the Public Advocates Office for Leave to File Under Seal Confidential Portion of Opening Brief filed on September 11, 2020; and
- The Motion of Southern California Edison for Admission of Late-Filed Errata into the Evidentiary Record filed on September 29, 2020, which identifies and requests that Exhibits SCE-18, Vol. 2E3 and SCE-52A2E2 be admitted into evidence.

All other outstanding motions for which rulings have not issued, are deemed denied.

54. Comments on Proposed Decision

The proposed decision of ALJs Sophia J. Park and Ehren D. Seybert in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on July 29, 2021 by SCE, Cal Advocates, TURN, SBUA, NDC, CUE, EPUC, PG&E, and SDG&E/SoCalGas. Reply comments were filed on August 3, 2021 by SCE, TURN, CUE, PG&E, and SDG&E/SoCalGas.

¹⁸⁴⁴ Ex. SCE-02, Vols. 7, 7E, 7E2.

Pursuant to Rule 14.3(c), “[c]omments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight.” Pursuant to Rule 14.3(d), replies to comments “shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties.”

We have carefully reviewed and considered the parties’ comments and made appropriate changes to the proposed decision where warranted. We find that all further comments not specifically addressed by revisions to the proposed decision do not raise any factual, legal, or technical errors that would warrant modifications to the proposed decision.

55. Assignment of Proceeding

Genevieve Shiroma is the assigned Commissioner, and Sophia J. Park and Ehren D. Seybert are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. With respect to individual uncontested issues in this proceeding, we find that SCE has made a prima facie just and reasonable showing, unless otherwise stated in this opinion.

Policy

2. SCE attributes the most significant driver of incremental funding in this GRC cycle to the “pressing need to undertake significant measures to reduce wildfire risk.”

3. Pursuant to AB 1054, SCE excludes from this proceeding the revenue requirement associated with \$1.575 billion in wildfire-related capital expenditures that are not eligible for an equity rate of return.

4. Over the last several years the State and this Commission have taken a number of steps to protect the state and its residents from utility-caused wildfires including, among others: the establishment of a framework and guidance for the submission of annual utility wildfire mitigation plans; the development of a statewide fire-threat map and delineation of areas subject to additional fire-safety regulations; the adoption of updated guidelines to mitigate wildfire risk and the impact on customers when a utility considers de-energizing the electric grid; authorization of a non-bypassable charge to support California's Wildfire Fund; and the establishment of an emergency disaster relief program for electric, natural gas, water and sewer utility customers.

5. On March 19, 2020, the Governor signed Executive Order N-33-20 requiring all individuals living in the State of California to stay home or at their place of residence, except as needed to maintain continuity of operation of the federal critical infrastructure sectors, in order to address the public health emergency presented by the COVID-19 pandemic.

6. It is undisputed in this proceeding that the economic impacts from COVID-19 are significant and ongoing.

7. It is not clear when or if the cumulative economic impacts of COVID-19 for this GRC cycle will be fully known.

8. Cal Advocates' proposed \$125 million decrease to SCE's estimated 2020 capital expenditure budget to account for the economic downturn associated with the COVID-19 pandemic lacks supporting analysis, evidence, and sufficient explanation.

9. There has been robust party participation throughout this proceeding.

Affordability

10. Although there are no established thresholds as to when a rate becomes unaffordable, SCE's requested revenue increase would result in rates that are relatively more unaffordable than in the recent past.

11. SCE's requested TY revenue requirement increase of approximately 20 percent would be a substantial increase for customers to absorb at one time.

12. Although the evidence shows that SCE's SAR has risen slower than inflation and the SARs of the other major California IOUs, the evidence also shows that household incomes for Californians, particularly low-income Californians, have not kept pace with inflation or the rise in SCE's rates and bills.

13. Affordability issues are largely driven by factors other than electric bills, such as languishing wages, unemployment rates, and costs of housing and other essential utility and non-utility expenses.

14. The affordability data and analyses presented by SCE and TURN provide a useful backdrop against which to evaluate SCE's requests in this proceeding.

15. It is appropriate for changes in purchasing power to be accounted for when comparing rates or bills over a multi-year period.

16. CPI may not accurately capture changes in purchasing power, particularly for lower income households, because household incomes have not increased at the same pace as CPI.

17. SCE's use of multiple predictive variables in its disconnections report may distort the regression analysis.

18. SCE's analyses of its historical disconnections data are not indicative of the impact that SCE's rates will have on disconnections for nonpayment during this GRC period due to caps on disconnections that will be in place during this GRC period.

19. In D.20-06-003, the Commission adopted an annual cap on the percentage of residential customer accounts that SCE can disconnect from utility service at seven percent for 2021, six percent for 2022, five percent for 2023, and 4 percent for 2024.

Risk-Informed Strategy and Business Plan

20. SCE filed its RAMP Report on November 15, 2018, in Investigation 18-11-006, and subsequently integrated the RAMP Report findings with its 2021 GRC Application and testimony.

21. The following top nine safety risks were identified through SCE's RAMP Report: (1) building safety; (2) contact with energized equipment; (3) cyberattack; (4) employee, contractor, and public safety; (5) hydro asset safety; (6) physical security; (7) wildfire; (8) underground equipment failure; and (9) climate change.

22. This is the first time a large IOU in California performed statistical risk assessment to evaluate company-wide risks and the effectiveness of proposed controls and mitigations (through the RAMP process), and then integrated the findings and recommendations from the Commission's Safety and Policy Division on the RAMP Report throughout its GRC application.

23. Cal Advocates' recommendation to quantify the key constraints associated with SCE's selection of risk mitigation programs, and TURN's recommendation to address issues of affordability in subsequent RAMP and GRC analyses, involve broader, potentially significant, changes to the risk framework applicable to all the large IOUs.

24. TURN's recommendation to use a specific timeframe for the probability of ignition calculation involves clarifications to D.18-12-014, which are currently being considered in R.20-07-013.

25. It is reasonable to defer consideration of Cal Advocates' and TURN's recommendations to quantify the key constraints with selection of mitigation programs, address affordability in subsequent RAMP and GRC analysis, and use a specific timeframe for the probability of ignition calculation, to R.20-07-013.

26. SCE is currently pursuing the relocation or purchase of private properties within potential inundation zones to reduce risk at the Thompson Dam on Catalina Island.

27. SCE provided reasonable justification for the inclusion of its hydro risk asset alternative mitigation plan in the 2018 RAMP Report.

28. SCE's use of a "top-down" system-wide risk modeling approach to inform its RAMP Report, and a "bottoms-up" risk modeling approach to inform its Wildfire Risk Model, results in different corresponding levels of projected risk reduction from deployed mitigation measures.

29. It is reasonable for SCE to provide a qualitative explanation of any divergences between its "top-down" and "bottoms-up" risk modeling results, including how the results support SCE's proposed mitigations programs, in future RAMP and GRC filings.

30. TURN's uncontested recommendation to include egress in the calculation of wildfire risk consequence would improve SCE's risk management approach.

31. Unless the issue of conditional risks is addressed in R.20-07-013, it is reasonable for SCE to incorporate egress, and other conditional risks as appropriate, in future RAMP and GRC risk modeling.

32. RSEs provide a useful point of comparison regarding the cost-effectiveness of proposed mitigations belonging to the same risk tranche.

Distribution Grid

33. SCE has significantly reduced many of its DIR capital forecasts from the RAMP forecast levels to help ensure adequate resources to address wildfire risks and the need for grid resiliency activities during this GRC cycle.

34. SCE's "unconstrained need" for DIR for 2019-2023, as identified in its RAMP report, is \$2.282 billion. In comparison, SCE's GRC forecast for 2019-2023 is \$858 million, \$1.424 billion less than the "unconstrained need" amount.

35. SCE's unopposed 2019 recorded and 2020-2021 forecasts for DIR capital expenditures are reasonable.

36. The record does not support the authorization of DIR capital expenditures beyond those requested by SCE.

37. SCE has not presented the DIR "unconstrained need" amount from its RAMP report for Commission review or approval and there has been no finding that this amount is reasonable or necessary during this GRC cycle for the provision of safe and reliable service.

38. The record is not clear whether SCE's requested expenditures for the Underground Structure Replacement program are sufficient to address critical safety risks that should be addressed during this GRC cycle.

39. Underground structure replacements that are classified as Grade F (at risk of failing with expected remaining life of 1-5 years) with either Code E (emergency, recommend replacing as soon as possible) or Code 1 (recommend replacing within the next 3 years) and rated very high or high in population proximity, population density, traffic rate, and falling debris hazard cannot be deferred and must be replaced within this GRC cycle.

40. Underground structures that are classified as Grade D (Poor, with a remaining life of 5-15 years) but with a Code 2 (recommend installing shoring

within the next 3 years) and rated very high or high in population proximity, population density, traffic rate, and falling debris hazard cannot be deferred and must install shoring within this GRC cycle.

41. The additional IR planning requirements proposed by CUE are not warranted.

42. A steady-state replacement plan is not likely to provide meaningful information for setting appropriate IR targets due to the difficulties in forecasting when steady-state can be achieved and the lack of consideration of the consequences of an in-service failure.

43. SCE's existing five-year DIR planning horizon, which is consistent with the RAMP planning horizon and updated on an annual rolling basis, is sufficient for near-term and longer-term DIR planning.

44. SCE's Distribution Inspection and Maintenance TY O&M forecast is reasonable.

45. Because we approve SCE's requested O&M funding for EOI, it is reasonable to adopt SCE's ODI forecast that excludes EOI costs.

46. SCE's use of the recorded four-year average (2014-2017) to develop its Distribution Preventative and Breakdown O&M Maintenance TY forecast is reasonable. SCE provides sufficient justification for excluding recorded 2018 costs from the forecast and 2019 recorded data confirms 2018 was an anomalous year.

47. SCE's adjustment to the Distribution Preventative and Breakdown O&M Maintenance forecast to account for new requirements in D.18-05-042 for Priority 3 maintenance items is reasonable given the volume of work SCE has identified it must complete to comply with the new requirements.

48. SCE's unopposed 2019 recorded capital expenditures for all Distribution Inspection and Maintenance activities are reasonable.

49. SCE's unopposed 2020-2021 capital expenditure forecasts for: (1) Streetlight Maintenance and LED Conversions, and (2) Distribution Tools and Work Equipment are reasonable.

50. Cal Advocates' 2020-2021 Distribution Claim forecast, which is based on a more recent five-year average (2015-2019) than SCE's forecast, is reasonable.

51. SCE's 2020 and 2021 forecasts for Distribution Preventative and Breakdown Capital Maintenance presented in rebuttal testimony, which incorporate corrections in the most recent errata and are lower than Cal Advocates' recommended forecasts, are reasonable.

52. The adjustments we make to SCE's requested capital expenditures for the EOI program constitute a small portion of SCE's overall funding request for the EOI program, and do not warrant any additional funding for Distribution Preventative and Breakdown Capital Maintenance.

53. SCE's unopposed methodology for deriving the 2020-2021 Distribution Transformers forecast, which is based on the capital expenditure forecast for 44 different distribution activities and a computer model developed by SCE, is reasonable.

54. For Distribution PLP Prefabrication costs, SCE proposes to use 2.83 percent of the forecast for the Distribution PLP Replacement Program.

55. For non-PLP Prefabrication costs, SCE proposes to use last year recorded (2018) costs as the forecast.

56. SCE's unopposed methodology for forecasting 2020 and 2021 Prefabrication costs is reasonable.

57. SCE's proposed changes to the SRIIM workforce classifications are unopposed and are reasonable.

58. SCE's proposal to increase the SRIIM headcount target to 2,465 is reasonable.

59. It is reasonable for SCE to continue to adjust the SRIIM target headcount level by one-half the percentage change in requested versus authorized T&D capital based on T&D programs that employ SRIIM workers.

60. It is appropriate for SCE's staffing levels of SRIIM workers to be aligned with the authorized funding for the capital programs that are supported by SRIIM workers.

61. SCE's proposal to modify the SRIIM headcount measurement to account for achieving the headcount level at some point in the last two quarters of the GRC cycle is not justified.

62. A SRIIM headcount measurement that measures headcount at a single point in time runs counter to the goals of SRIIM because it does not incentivize SCE to maintain a workforce at the targeted level.

63. A SRIIM headcount measurement that uses an average headcount over the last quarter of the GRC cycle enables variations in headcount to be taken into account and provides incentives to maintain the targeted headcount level over a period of time.

64. SCE's proposed modifications to the capital investment component of the SRIIM will continue to incentivize spending in safety and reliability while providing SCE with greater flexibility to address emergent safety and reliability risks and unexpected customer requests.

Meter Activities

65. SCE's unopposed Meter O&M forecasts are adequately justified and reasonable.

66. With the exception of SCE's forecast for Meter Engineering routine meter work, SCE's 2019 recorded and 2020-2021 capital expenditure forecasts for Meter Activities are unopposed.

67. SCE's unopposed 2019 recorded and 2020-2021 capital expenditure forecasts for Meter Activities are reasonable.

68. While the significant variation in SCE's year-to-year routine meter work supports the use of a three-year average, the specific event leading to SCE's increased purchases in 2017, namely, the decision by a manufacturer to move a major portion of its meter production to a new location, is not expected to be a regular occurrence or a reliable indicator of future expenditures.

69. It is common for GRCs to update forecasts based on recent recorded information, especially for plant-related items.

70. It is reasonable to calculate the capital expenditure forecast for Meter Engineering routine meter work using 2019 recorded data along with a three-year average, based on 2016, 2018, and 2019 recorded data, for 2020-2021.

Transmission Grid

71. SCE's TY forecasts for the following Transmission Grid O&M activities are unopposed: Insulator Washing, Roads and Rights of Way, Transmission Underground Structure Inspection, and Transmission Support Activities.

72. SCE's unopposed Transmission Grid TY O&M forecasts are adequately justified and reasonable.

73. Starting in 2021, SCE plans to perform aerial inspections on one-third of SCE's non-HFRAs every year.

74. SCE has historically performed limited line patrols via helicopter.

75. Aerial inspection of non-HFRAs involves different work than limited line patrols as it focuses on detailed asset inspections (including infrared, corona, and high-definition imaging).

76. SCE's forecast methodology for its Transmission Line Patrols O&M forecast is based on last year recorded (2018) costs with an adjustment for planned aerial inspections.

77. SCE's incremental costs for planned aerial inspections is based on SCE's plan to inspect one-third of non-HFRAs every year, the estimated costs per mile scanned, the costs of a camera sensor operator, and the costs for processing and reviewing aerial inspection results.

78. The workpaper submitted by SCE in support of its Transmission Line Patrols O&M forecast indicates that the incremental cost for the planned aerial inspection work of non-HFRAs is \$2.626 million.

79. Given the scope of planned work for the new aerial inspections of non-HFRAs, Cal Advocates' proposal to normalize (*i.e.*, reduce by two-thirds) SCE's incremental costs is not justified.

80. Based on the supporting documentation provided by SCE, it is reasonable to approve a Transmission Line Patrols TY O&M forecast based on 2018 recorded costs with an adjustment of \$2.626 million for the incremental aerial inspection work in non-HFRAs.

81. SCE's unopposed TY forecasts for the Transmission O&M Breakdown, Transmission O&M Encroachments, and Maintenance for FAA Lighting sub-activities within the Transmission O&M Maintenance activity are adequately justified and reasonable.

82. SCE fails to justify using a four-year average to determine the Transmission O&M Maintenance sub-activity TY forecast.

83. SCE's recorded costs from 2014-2018 for the Transmission O&M Maintenance sub-activity demonstrate a yearly downward trend.

84. Given that the recorded expenses for the Transmission O&M Maintenance sub-activity have shown a downward trend over three or more years, Cal Advocates' proposal to base the TY forecast on the last recorded year is reasonable.

85. SCE's TY forecast for the Aerial Inspection Maintenance Program sub-activity, based on recorded EOI "find rates" and average replacement costs from past work orders, is adequately supported and reasonable.

86. There is a lack of justification for Cal Advocates' proposal to normalize (*i.e.*, reduce by two-thirds) SCE's TY forecast for the Aerial Inspection Maintenance Program sub-activity.

87. SCE fails to justify its requested \$2.455 million increase above 2018 recorded costs (which would more than double its 2018 recorded costs) for Telecommunications Inspection and Maintenance activities.

88. SCE was required to conduct regular and ongoing inspections of its telecommunication lines prior to modifications to GO 95 adopted in D.17-12-024, and SCE fails to explain how the modifications adopted in D.17-12-024 would justify a more than doubling of its 2018 recorded costs.

89. It is unclear how much of the forecast work for Telecommunications Inspection and Maintenance is incremental to the level and types of activities conducted in prior years.

90. SCE does not adequately explain why its 2018 recorded costs for Telecommunications Inspection and Maintenance would be insufficient to

conduct the inspections required pursuant GO 95 and associated maintenance work.

91. It is reasonable to approve a Telecommunications Inspection and Maintenance TY forecast based on 2018 recorded costs.

92. SCE has provided adequate justification for its TLRR TY forecast.

93. SCE forecasts fourteen TLRR projects to be started or completed in the TY and expects the level of TLRR work and costs to continue at the same level through this GRC cycle.

94. SCE's projected scope of TLRR work for this GRC cycle is reasonable in light of NERC/WECC compliance deadlines and the fact that it is based on actual inspection results.

95. With the exception of SCE's forecast expenditures for the Aerial Inspection Maintenance sub-activity within Transmission Capital Maintenance, SCE's 2019 recorded and 2020-2021 forecast Transmission Grid capital expenditures are unopposed.

96. SCE's unopposed 2019 recorded and 2020-2021 forecast Transmission Grid capital expenditures are adequately justified and reasonable.

97. SCE's Aerial Inspection Maintenance sub-activity capital forecast methodology, based on recorded EOI "find rates" and pole replacement costs under other programs, is adequately supported and reasonable with the adjustment of a pole replacement "find rate" of 12 percent rather than the 15 percent proposed by SCE.

98. In a data request response to Cal Advocates, SCE indicated that the pole replacement "find rate" based on preliminary findings from SCE's aerial inspections of its HFRAAs is a little over 12 percent.

99. Given the lack of historical costs for the Aerial Inspection Maintenance program and relatively high average unit costs, it is reasonable to adopt the more conservative “find rate” of 12 percent for pole replacements.

100. It is reasonable to adopt capital expenditures of \$17.969 million (\$nominal) for the Aerial Inspection Maintenance sub-activity TY forecast based on a total notification count of 8,044; pole replacement frequency rate of 12 percent; application of a 30 percent reduction to account for duplicative work under the pole program; and an average unit cost of \$24,661.

101. A balancing or memorandum account for the Aerial Inspection Maintenance sub-activity is not warranted.

Substation

102. SCE’s uncontested Monitoring and Operating Substations; Inspections and Maintenance; and Capital-Related Expense and Other TY O&M forecasts are reasonable.

103. SCE’s TY O&M forecast for GCC based on last year recorded (2018) costs is reasonable.

104. Cal Advocates’ recommended GCC labor and non-labor forecasts are in response to SCE’s initial forecasts, which SCE subsequently corrected because SCE had inadvertently used an incorrect labor to non-labor ratio.

105. SCE’s corrected labor forecast for GCC is less than Cal Advocates’ recommended labor forecast.

106. There is no basis to adopt SCE’s initial non-labor forecast for GCC.

107. SCE has provided adequate justification for an increase above 2018 recorded costs for the TY GNS forecast.

108. SCE’s recorded GNS costs for 2014-2018 reflect a linear upward trend.

109. SCE anticipates a substantial increase in the number of technology assets and systems put into service during this rate case cycle in support of the Grid Mod program.

110. Cal Advocates does not dispute the incremental scope of work that SCE forecasts for GNS.

111. Cal Advocates' recommended GNS forecast based on historical 2016-2018 costs would not provide adequate funding to support approved Grid Mod projects, which require GNS support.

112. SCE has failed to justify normalizing its 2021-2023 forecast costs related to Grid Mod to determine the TY forecast for GNS.

113. SCE does not provide any explanation as to why GNS costs related to Grid Mod are expected to increase from \$3.188 million in 2021 to \$4.501 million in 2022 and \$8.572 million in 2023.

114. It is reasonable to approve incremental Grid Mod-related costs for GNS based on the 2021 forecast rather than the 2021-2023 normalized forecast.

115. SCE's unopposed 2019 recorded and 2020-2021 forecast substation capital expenditures are reasonable.

Grid Modernization, Grid Technology, and Energy Storage

116. SCE's unopposed O&M forecast for T&D Deployment Readiness is reasonable.

117. SCE's itemized O&M forecast for IT Project Support is based on actual contractual pricing negotiations.

118. Cal Advocates does not contest any of SCE's proposed IT Project Support O&M activities in this proceeding, or explain why a three-year average better reflects the level of IT Project Support work SCE expects to perform.

119. SCE's forecasted O&M IT Project Support costs are reasonable and reflect the level of work SCE expects to perform.

120. SCE attributes increases in its capital expenditure forecast for E&P Tools, as compared to its 2018 GRC request, to the following: (1) additional requirements that have emerged from the DRP proceeding; (2) increased deployment complexity; and (3) the maturity and suitability of products currently available in the market.

121. SCE's combined E&P Tools forecast is based on vendor solicitation RFP results.

122. D.17-09-026 and D.18-02-004 were adopted after SCE filed its 2018 GRC request.

123. No party took issue with the need for the E&P Tools, specifically disputed SCE's forecast methodology, or questioned whether SCE's requested level of funding corresponds to products currently available in the market.

124. In approving funds for SCE's E&P Tools, D.19-05-020 states "if additional funds become necessary, then SCE may seek to establish that necessity in the next GRC."

125. SCE's 2019 recorded and 2020-2021 forecast E&P Tools capital expenditures are reasonable.

126. SCE attributes increases in its capital expenditure forecast for the GMS, as compared to its 2018 GRC request, to the following: (1) basing the 2021 GRC forecast on the results of a competitive solicitation; (2) evolving technical solutions and additional project scope for addressing the GMS business requirements; and (3) moving from a three-year to five-year deployment.

127. Parties do not dispute the overall need for the GMS; the need for a more robust Data Historian, business rules functionality, and end-to-end testing costs; or the specific cost components underlying SCE's GMS forecast.

128. While the basis of SCE's GMS forecast is adequate and generally well-supported, SCE provides little evidence demonstrating why GMS deployment should be extended from three to five years.

129. It is reasonable to approve \$110.553 million in capital expenditures for the GMS over the 2019-2021 period, including a \$5 million reduction from SCE's request to account for the two-year extension of labor costs.

130. With the exception of RDA, SCE's 2019 recorded and 2020-2021 capital expenditure forecasts for Grid Modernization Automation are unopposed.

131. SCE's unopposed 2019 recorded and 2020-2021 capital expenditure forecasts for Grid Modernization Automation are reasonable.

132. While it is possible the VOS Study contains non-response bias, the direction of the bias cannot be determined.

133. VOS Study survey respondents reasonably represent SCE's mix of customers in terms of business type, usage, and location.

134. The VOS Study accounts for backup power resources, and SCE sufficiently explains how the use of an average CMI value accounts for other programs that target reliability.

135. Results from the VOS Study indicate that C&I customers place a value on reliability (\$714/CMI) several magnitudes higher than that of residential customers (\$0.07/CMI).

136. SCE's VOS Study has been weighted to reflect the mix of residential and non-residential customers served by SCE.

137. Calculating the BCA of reliability-driven automation by circuit or circuit-segment would take into consideration the associated cost and types of customers (i.e., corresponding CMI values) that would benefit from additional automation.

138. SCE does not quantify the potential impact of multiple current injections on distribution asset life, and there is limited record concerning the potential safety issues associated with TURN's RCS/RFI-only approach.

139. TURN does not provide any evidence in this proceeding to support its claim that "circuit ties are very expensive ways of achieving reliability."

140. SCE's RDA request over this GRC period is less than half of the annual RDA-related funding the Commission approved in SCE's last GRC.

141. SCE's 2019 recorded and 2020-2021 forecast RDA capital expenditures are reasonable.

142. SCE's unopposed 2019 recorded and 2020-2021 forecast Grid Modernization Communications capital expenditures are reasonable.

143. SCE's unopposed 2019 recorded and 2020-2021 forecast Subtransmission Relay Upgrade Project capital expenditures are reasonable.

144. The specific projects SCE proposes to research at the Westminster Lab and EDEF concern issues that are both relevant and unique to SCE.

145. SCE's RFP results demonstrate that upgrading the EDEF and performing in-house testing costs is the most cost-effective option for meeting SCE's needs over this GRC period.

146. SCE's unopposed 2019 recorded and 2020-2021 forecast Grid Technology capital expenditures are reasonable.

147. Regarding Grid Technology O&M, Cal Advocates does not provide any explanation for why 2019 forecast data should be substituted for 2017 recorded

data, beyond highlighting that the expense level in 2017 is higher than previous years.

148. SCE's Grid Technology O&M forecast uses a five-year average to account for year-to-year variation in expenses, and is reasonable.

149. The Commission previously determined the DESI and Mira Loma energy storage projects to be necessary.

150. SCE's uncontested 2019-2021 capital expenditure and TY O&M requests for the DESI pilots are reasonable.

Load Growth, Transmission Projects, and Engineering

151. The growth of DERs can cause criteria violations that compromise the safety and reliability of the grid.

152. Due to uncertainty in the timing and magnitude of potential DER-driven reliability violations, SCE and Cal Advocates agree it is appropriate to remove DER-Driven Grid Reinforcement costs from SCE's Load Growth forecast in this GRC, and instead track and record capital expenditures associated with the DER-Driven Grid Reinforcement program in a memorandum account.

153. The disaggregated DER and demand growth SCE used to develop its 2021 GRC request was affirmed in D.18-02-004 and the August 1, 2018, Administrative Law Judge's Ruling in R.14-08-013.

154. SBUA does not identify any specific instances of utility mismanagement in this proceeding that might warrant a formal audit, nor does SBUA provide any specific criticisms of, or alternative recommendations to, the individual Grid Modernization forecasts SCE presented in this GRC.

155. SBUA's recommendation that SCE should recover the costs of their distribution assets on a "percent of utilization" basis fails to account for anticipated peak loading events.

156. SCE provided adequate justification for its 2019-2021 Load Growth capital expenditure forecast.

157. SCE's uncontested 2019 recorded and 2020-2021 forecast Transmission Projects capital expenditures are reasonable.

158. SCE's uncontested TY O&M forecast for the Grid Engineering GRC Activity is reasonable.

159. SCE's TY O&M forecast for Load Side Support is based on a three-year average of labor costs (2016-2018), and 2018 recorded non-labor costs plus an increase to account for specialized investigation work performed by a third-party firm and contract employees for specialized engineering.

160. SCE's recorded 2018 non-labor expenses for Load Side Support (\$0.159 million) are lower than its recorded expenses for both 2016 (\$0.186 million) and 2017 (\$0.170 million).

161. Cal Advocates' recommendation to use 2016-2018 recorded non-labor costs for the Load Side Support forecast does not take into consideration the incremental work SCE expects to perform in 2021.

162. SCE provided adequate justification for both the labor and non-labor costs in its TY O&M Load Side Support forecast.

New Service Connections and Customer Requested Modifications

163. SCE has failed to adequately justify its forecast for residential meter installations.

164. SCE has consistently over-forecast new residential meters since the 2012 GRC.

165. Although SCE made some adjustments to its residential new meter forecast methodology since its last GRC, SCE's revised methodology does not adequately address the consistent upward bias demonstrated by TURN.

166. SCE primarily relies on Moody's forecast of housing starts for its new residential meter forecast.

167. SCE's adjustments in this GRC reduced Moody's housing starts forecast by 8.6 percent in 2021, 10.2 percent in 2022, and 4.1 percent in 2023.

168. SCE's 2018 GRC new residential meter forecast using Moody's housing starts forecast was 20 percent too high for 2018 and 25 percent too high for 2019.

169. In this GRC, SCE initially forecast 2019 residential new connections expenditures of \$128.246 million but only recorded \$110.480 million primarily due to fewer residential meter installations than were forecast.

170. TURN's proposal to apply a lower number of forecast housing starts to SCE's calculated coefficients from its regression model to develop the residential meter forecast is reasonable.

171. TURN's proposal to use an average of actual housing starts from 2015-2019 to forecast housing starts is reasonable.

172. Data from 2013-2019 demonstrates a leveling off of housing starts.

173. It is reasonable to adopt a more conservative residential meter forecast given the economic uncertainties during this rate case period due to the impacts of the COVID-19 pandemic, which are still unknown, and therefore, not accounted for in the parties' forecasts.

174. TURN's proposed residential meter forecast and corresponding residential new connections capital expenditure forecasts for 2021-2023 are reasonable.

175. It is reasonable to adopt a 2020 residential meter forecast of 29,248 and corresponding residential new connections capital expenditure forecast of \$115.086 million based on recorded lagged housing starts.

176. SCE's unopposed 2019 recorded residential new connections capital expenditures are reasonable.

177. SCE accepts TURN's proposal for a reduced commercial meter set forecast.

178. TURN's forecast of 4,751 commercial sets annually for 2021-2023, based on the average number of commercial meters installed over the last five recorded years (2015-2019), is reasonable.

179. SCE's unopposed methodology for translating the commercial gross meter set forecast to the forecast of commercial new connections work activities is reasonable.

180. Consistent with the adopted forecast for 2021-2023, it is reasonable to adopt a commercial meter forecast of 4,751 for 2020, which results in corresponding commercial new connections capital expenditures of \$85.804 million (\$nominal).

181. SCE's unopposed 2019 recorded commercial new connections capital expenditures are reasonable.

182. SCE's unopposed 2019 recorded agricultural new connections capital expenditures are reasonable.

183. SCE has failed to adequately justify its 2020 and 2021 agricultural new connections capital expenditure forecasts.

184. SCE's recorded agricultural new connections capital expenditures from 2016-2019 have shown a consistent downward trend.

185. SCE's capital expenditure forecast methodology for agricultural new connections yielded a 2019 forecast of \$6.817 million, whereas SCE's 2019 recorded costs were \$3.409 million.

186. In the absence of an adequately justified forecast for agricultural new connections, and given that there has been a downward trend for three or more years, it is reasonable to adopt capital expenditures for 2020 and 2021 based on SCE's last year recorded (2019) costs.

187. SCE's unopposed 2019 recorded capital expenditures for Streetlights new connections are reasonable.

188. SCE's uncontested methodology and forecast electrolier unit costs for calculating the 2020 and 2021 Streetlights new connections forecasts are reasonable.

189. The 2020 and 2021 Streetlights new connections forecasts are dependent on the forecast for residential gross meter sets.

190. SCE's unopposed 2019 recorded costs and updated 2020-2021 forecast capital expenditures for distribution and transmission relocations, which incorporate 2019 recorded data, are reasonable.

191. SCE's unopposed 2019 recorded expenditures for Rule 20A conversions are reasonable.

192. The updated balance in the Rule 20A Balancing Account taking into account 2019 recorded amounts is \$35.507 million.

193. It is reasonable to adopt TURN's proposal, accepted by SCE, of applying the Rule 20A Balancing Account balance to SCE's forecasts for 2021-2024.

194. SCE's Rule 20A forecasts for 2020 and 2021, based on the five-year (2014-2018) average of recorded costs, are reasonable.

195. SCE's updated 2020 and 2021 forecasts for Rule 20 B/C conversions, which are based on the five-year (2015-2019) average of actual recorded expenditures for each sub-activity, are reasonable.

196. SCE's unopposed 2019 recorded expenditures for Rule 20 B/C conversions are reasonable.

197. SCE's updated 2020 and 2021 forecasts for distribution added facilities, which are based on five-year (2015-2019) average costs and use of a full constant-to-nominal conversion rate, are reasonable.

198. SCE's unopposed 2019 recorded expenditures for distribution added facilities are reasonable.

199. SCE's unopposed 2019 recorded costs and 2020-2021 forecasts for Transmission/Substation Added Facilities and WDAT/TOT/Gen-Tie are reasonable.

Poles

200. SCE's unopposed 2019 recorded and 2020-2021 forecast capital expenditures for Steel Stub Installations and Wood Pole Disposal are adequately justified and reasonable.

201. SCE's unopposed 2019 recorded capital expenditures for Distribution and Transmission Pole Replacements are reasonable.

202. SCE identifies poles requiring replacement through Pole Loading Program assessments, Intrusive Pole Inspections, and planners during the normal course of work.

203. SCE's forecast number of pole replacements includes the poles that SCE has already identified as requiring replacement during the 2019-2021 period and poles that SCE forecasts it will identify and need to replace during the 2019-2021 period.

204. For pole replacements driven by the Pole Loading Program assessments and the Intrusive Pole Inspection program, SCE's forecast is based on the number of assessments or inspections, the expected failure rate, and the timeframe for replacement.

205. SCE's forecast volumes of pole replacements driven by non-programmatic activities are based on average volumes for 2016-2018.

206. No party disputes SCE's 2020 and 2021 forecast unit cost for each pole type, which SCE developed by analyzing historical replacement costs from

closed work orders, as well as other factors that would impact the unit cost going forward.

207. SCE uses an average of 2021-2023 unit costs for forecasting its 2021 pole replacement capital expenditures in order to take into account cost changes in the post-test years.

208. SCE has provided adequate justifications for its Distribution and Transmission Pole Replacements forecasts.

209. SCE provides reasonable justification for why its 2019 pole replacement costs were lower than forecast and why the 2019 level of activity is not likely to be representative of 2020 and 2021 activity.

210. SCE's forecast level of pole replacements is adequately justified and reasonable in light of the need for SCE to comply with new remediation timeframes adopted by the Commission in D.17-12-024.

211. SCE provides adequate justification for its forecast unit costs for pole replacements.

212. Continuation of the PLDPBA ensures that any over- or under-collection for pole replacements will be returned to, or recovered from, customers.

213. SCE's 2019 recorded joint pole capital credits are unopposed and reasonable.

214. SCE derives its 2020 and 2021 forecasts for joint pole capital credits by using the 2018 average amount billed per pole and multiplying this amount by the pole replacement quantities for the forecast period.

215. Cal Advocates' methodology for calculating joint pole credits is based on dividing the total dollars billed in a calendar year with the total pole replacements in a calendar year.

216. Cal Advocates' methodology for calculating joint pole credits does not take into account the timing difference between when a pole is replaced and receipt of the pole credit from the joint owner.

217. SCE's credit per pole calculation is based on an analysis of 2018 work order total credits and the total number of poles replaced under each work order, regardless of whether the pole replacement was completed in 2018 or a prior year.

218. SCE's methodology for calculating the average credit per pole is more likely to yield an accurate forecast compared to Cal Advocates' methodology.

219. SCE's 2020 and 2021 forecast joint pole credits are reasonable.

Vegetation Management

220. D.17-12-024 increased vegetation clearances for areas located within the CPUC's High Fire-Threat District map, with a requirement that full compliance be achieved in Zone 1 and Tier 2 areas no later than June 30, 2019.

221. SCE's 2018 recorded vegetation management costs do not reflect the increased work inventory under the new clearance requirements adopted in D.17-12-024.

222. Cal Advocates does not dispute any aspect of SCE's TY O&M forecast methodology for Distribution Routine Vegetation Management.

223. Cal Advocates does not dispute SCE's O&M forecast for Transmission Routine Vegetation Management, which uses a similar itemized methodology as SCE's O&M forecast for Distribution Routine Vegetation Management.

224. SCE's TY O&M forecast methodology for Distribution Routine Vegetation Management is well-supported, and is consistent with the amount of work SCE performed during the first two quarters of 2019.

225. SCE's unopposed TY O&M forecast for Transmission Routine Vegetation Management is well-supported and reasonable.

226. SCE's unopposed TY O&M forecast for Dead, Dying, and Diseased Tree Removal is reasonable.

227. SCE's forecast for the HTMP assumes SCE will perform 100,000 tree mitigations per year (2021-2023), along with the removal of 20,000 trees under this program in 2021, escalating to 25,000 in 2022 and 30,000 in 2023.

228. SCE's 2020-2022 WMP decreases the annual volume of targeted HTMP assessments from SCE's prior WMP, from 125,000 to a projected 75,000 annual assessments over the 2020-2022 timeframe.

229. SCE fails to address the underlying reasons that led SCE to lower the number of HTMP assessments in its 2020-2022 WMP.

230. As part of the GSRP settlement adopted in D.20-04-013, SCE agreed to "participate in a study to evaluate the need for and effectiveness of its current risk calculator in promoting tree removal to reduce wildfire ignition risks, considering other mitigation measures by Southern California Edison."

231. At the time opening briefs were filed in this proceeding the results of SCE's study on the effectiveness of the tree risk calculator were still pending.

232. SCE's 2019 data indicates a high number of trees marked for removal (16,078) but a low number of trees actually removed (5,917).

233. SCE provides data demonstrating a higher rate of tree removal from October 2019 through May 2020 compared to 2019.

234. SCE forecasts a 5-12 percent failure rate from tree assessments in HFRA's.

235. The assessment of 75,000 trees per year under the HTMP is consistent with SCE's 2020-2022 WMP.

236. An 11 percent tree failure rate is within SCE's forecasted range of failures based on tree assessments in HFRAs, and takes into consideration 2019 and early 2020 tree removal data.

237. SCE's VMP update includes two components: (1) new Unit Rates stemming from the conclusion of a competitive bidding process in 2019, and (2) the modification of those new Unit Rates stemming from the enactment of SB 247.

238. Because SCE uses Unit Rates (as opposed to hourly rates) to forecast its VMP costs, and pre-SB 247 Unit Rates are driven by a variety of cost increases that vendors have sought to add to their contracts, it is impossible to isolate the specific wage rate increases mandated by SB 247.

239. SCE added two relatively higher cost vendors in its calculation of the Unit Rates under SB 247.

240. In D.20-12-005, the Commission found the creation of a VMBA, along with the requirement that recovery of costs in excess of 120 percent of the authorized amount for vegetation management activities be made via application, would: promote efficiency across activities that are similar, or that are expected to become similar over time; support ongoing wildfire mitigation activities, even if costs above authorized levels become necessary; allow the return of unused funds to ratepayers; and allow for enhanced review of larger cost recovery amounts.

241. Cal Advocates and TURN provide various recommendations concerning the creation of a VMBA, all of which would result in a lower threshold for any excess costs above the amounts approved in this decision to be subject to reasonableness review.

Wildfire Management

242. SCE's GRC analysis indicates that wildfire risk associated with overhead distribution-level facilities can be reduced by 60 percent through the deployment of covered conductor.

243. SCE proposes to deploy 6,272 cumulative miles of covered conductor totaling \$3.4 billion (2019-2023, including \$93 million associated with tree attachment removal), based on the maximum amount of covered conductor SCE projects it can install given available resources.

244. TURN proposes that SCE install 2,500 circuit miles of covered conductor totaling \$892 million in capital expenditures (2019-2023).

245. Cal Advocates proposes that SCE install 1,000 miles of covered conductor in 2021 and, in the Joint Comparison Exhibit, reviewed and accepted a forecast of 1,000 miles in 2022 and 1,000 miles in 2023.

246. SCE's REAX fire propagation model uses Monte Carlo simulations to analyze the consequence of ignitions by location, with the corresponding consequence estimated as a product of the number of structures burned within a modeled fire perimeter and the fire volume (acres burned) associated with that fire perimeter within the first six hours of ignition.

247. SCE's risk buydown curve uses average REAX wildfire consequence scores to illustrate the relative risk reduction from installing an additional circuit mile of covered conductor.

248. The first 3,750 miles on the risk buydown curve have REAX scores that account for 98 percent of the risk within the first six hours of ignition in SCE's HFTD.

249. Aside from undergrounding, covered conductor is one of the most expensive wildfire mitigation measures available.

250. The deployment of 3,750 circuit miles of covered conductor would be the largest installation of covered conductor among the California IOUs.

251. SCE has not identified any potential redundancies among its proposed wildfire mitigation measures that might decrease spending on other mitigations in the locations where covered conductor is deployed.

252. SCE's Wildfire Risk model is focused on evaluating risk at the circuit level and does not consider operational design issues.

253. It is not clear, based on the record of this proceeding, whether the 20 percent adder SCE proposes for operational design considerations would result in additional covered conductor being installed inside or outside SCE's HFRA's.

254. SCE does not sufficiently address the PSPS benefits from deploying covered conductor.

255. SCE does not explain how its decision tree logic better supports a 60/40 split between fire resistant pole wraps to composite poles, while TURN does not provide any basis for its proposed 75/25 split.

256. Tree attachments pose a unique wildfire risk due to the potential for the corresponding trees to become diseased or die.

257. Even where covered conductor has been deployed, there is still a risk that utility-caused ignitions could occur.

258. HFRA's not addressed by covered conductor will be subject to a host of other wildfire mitigation measures approved in this decision.

259. Since the Wildfire Risk model is focused on evaluating risk at the circuit level, as opposed to operational design considerations, it is likely additional operational covered conductor miles will be installed during actual design and deployment.

260. If the additional covered conductor operational miles were installed in SCE's non-HFRAs, they would reduce the risk reduction potential of the covered conductor circuit miles adopted in this decision.

261. SCE's unopposed 2019-2023 capital expenditure and TY O&M requests for fusing mitigation are reasonable.

262. It is uncontested that the poles, bare conductor, and fuses replaced as a result of SCE's wildfire mitigation program will be retired and no longer used and useful.

263. While 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), the Commission has also made exceptions to this general policy.

264. In D.20-04-013 the Commission adopted settlement language stating that "SCE will not be subject to disallowance or reduced authorized return associated with existing investment in recently replaced poles that are replaced in connection with GSRP activities."

265. The mitigation of wildfire risk through covered conductor deployment is supported by D.20-04-013, SCE's wildfire risk analysis, and party proposals in this proceeding.

266. Replacing fuses in SCE's HFRAs will clear faults faster and minimize the number of customers impacted by an outage.

267. SCE's wildfire risk analysis demonstrates that 3,750 circuit miles of bare conductor in SCE's HFRAs are inadequate to address near-term ignition risks.

268. The level of covered conductor deployment approved in this decision focuses on the riskiest circuit segments located in SCE's HFRAs.

269. There have been significant developments in wildfire-related policies, analyses, and maps over the past five years.

270. SCE's uncontested TY O&M and 2019-2023 capital expenditure requests for HFRA Sectionalizing Devices are reasonable.

271. The final results of SCE's DFA pilot have not been presented or analyzed by parties for the Commission.

272. SCE's unopposed 2019 recorded and 2020-2023 forecast Targeted Undergrounding capital expenditures are reasonable.

273. SCE's uncontested TY O&M request for the PMO program is reasonable.

274. SCE has provided adequate justification for how its wildfire management OCM program is new and incremental to other OCM activities.

275. With the exception of vertical switch replacement, SCE's 2019 recorded and 2020-2023 capital expenditure forecasts for EOI are unopposed.

276. SCE's unopposed 2019 recorded and 2020-2023 capital expenditure forecasts for EOI are reasonable.

277. SCE does not substantively respond to evidence presented by TURN's witness Mr. Stephens indicating it is unlikely for arcing and incandescent particles to result from misaligned switch contacts, and that proper maintenance can, in most circumstances, be used to fix the problem of loose vertical switch mountings.

278. Under the EOI Remediation Program, SCE inspects approximately half of its distribution assets in HFRA's each year and remediates potential issues as they are observed.

279. In Resolution WSD-004, approving SCE's 2020-2022 WMP, the Commission found SCE's EOI Program "represents a strength of the WMP."

280. SCE provides a clear description of the differences between distribution EOI inspections and traditional ODI inspections, and provides sufficient

justification to explain how its EOI inspection and repair forecasts are incremental and avoid double-counting.

281. SCE has taken adequate steps to avoid duplication between its transmission repair and distribution repair forecasts.

282. SCE has adequately justified its O&M forecasts for EOI distribution aerial inspections and PMO IT projects, including why IT projects currently in rates are distinct from SCE's current PMO IT request.

283. SCE's uncontested TY O&M forecast for the Infrared and Corona Inspection Program is well-supported and reasonable.

284. SCE's unopposed TY O&M and 2019-2021 capital expenditure requests for PSPS Execution are reasonable.

285. SCE's assumed 30 PSPS events per year is higher than what SCE included in its 2018 RAMP Report.

286. SCE's unopposed TY O&M forecast for PSPS Customer Support is reasonable.

287. In D.21-01-018, the Commission adopted rates, tariffs, and rules to facilitate the commercialization of microgrids pursuant to SB 1339.

288. In D.21-01-018, the Commission adopted an Equity Resiliency budget carve out in SGIP to provide incentives for vulnerable customers and critical service facilities in HFTDs or those who have been affected by PSPS events.

289. SCE does not provide sufficient evidence demonstrating why the CRERIP is warranted given the existing focus and incentives provided through SGIP, nor does it fully explain why the proposed rebate is needed for "larger facilities that SCE is targeting under CREIP."

290. SCE's unopposed 2019 recorded and 2020-2023 forecast capital expenditures for the Enhanced Situational Awareness program are reasonable.

291. SCE has provided adequate justification demonstrating why the costs and personnel within the Emergency Management organization are distinct, and requested separately, from the Situational Center.

292. SCE has provided adequate support for its TY O&M forecast for the Enhanced Situational Awareness program.

293. It would be inconsistent to fund SCE's proposed capital expenditures for Enhanced Situational Awareness without also including funding for the various expenses to utilize the data and maintain the equipment.

294. SCE's unopposed 2019 recorded and 2020-2023 forecast for Fire Science and Advance Modeling capital expenditures are reasonable.

295. SCE's TY O&M forecast for Fire Science and Advance Modeling is well-supported, and SCE has provided sufficient justification demonstrating why funding for the Fire Science program is incremental.

296. The projected scope and costs of SCE's WCCP are significantly greater than any of SCE's other proposed wildfire mitigation activities, and contain unit costs that are comparatively less established.

T&D Other Costs and Other Operating Revenue

297. SCE's unopposed T&D capital expense ratios are reasonable.

298. SCE's unopposed TY O&M forecasts for T&D Other Costs are reasonable.

299. SCE's T&D OOR forecasts for ownership charges, transmission and distribution services, generation radial tie-lines, tie-line facilities rental agreements, miscellaneous revenue, Customer-Financed Added/Interconnection Facilities, and NEM are uncontested.

300. SCE's proposed Annual Attachment Rental Fee of \$20.04 for July 1, 2020 to June 30, 2021, and \$21.36 for July 1, 2021 through June 30, 2024, was approved through Energy Division's disposition of SCE Advice Letter 4252-E.

301. SCE's proposed penalties for unauthorized rental attachments and fees for conduit rentals are uncontested and are reasonable.

302. SCE charged third-party attachers a single non-recurring P&E fee of \$80 from 2003 to April 1, 2019.

303. SCE's current P&E fee of \$186.78 per customer request represents a 133.475 percent increase from the prior fee in effect.

304. There is nothing in the record to indicate the number of pole attachment applications that were invoiced and paid since April 1, 2019.

305. SCE's application proposed a continuation of the \$232 post-attachment fee adopted as part of SCE's 2018 GRC, but SCE revised the fee to \$215.67 in rebuttal testimony to reflect more recent operations, staffing, and vendor costs.

306. SCE's post-attachment inspection fee was developed following findings from a Commission-adopted settlement which determined that overloaded poles were a contributing factor in the 2007 Malibu Canyon fire.

307. In a sampling of inspections conducted in 2019, SCE observed a 68 percent failure rate on inspections performed of third-party attachments.

308. P&E and post-attachment inspection fees address the incremental work to manage and administer new pole attachment requests by third-parties, whereas SCE's Annual Attachment Rental Fee addresses the ongoing cost of owning and maintaining SCE's poles.

309. SCE provides adequate justification for its P&E and post-attachment inspection fees.

310. One of the terms of the proposed settlement agreement between SCE and Conterra is that Conterra would not be required to submit ongoing pole loading calculations with its requests for pole attachments.

311. There is nothing in the record of this proceeding to indicate how waiving the requirement to submit pole loading calculations would impact safety or other cost considerations.

312. In D.98-10-058, the Commission found that a utility's engineering studies should "avoid duplicative costly engineering analysis which could undermine the economic advantages of building a carrier's own facilities."

313. SCE does not respond to Conterra's assertion that ECS has an unfair advantage (by not incurring pole attachment charges) to the detriment of broadband competition.

Customer Interactions

314. SCE's TY O&M forecast for Billing Services is based on 2018 recorded costs plus adjustments.

315. During 2015-2016 NEM and CCA exceptions grew while ESC exceptions decreased.

316. SCE's 2014-2017 data does not show a strong correlation between meter usage exceptions and CCA enrollment and NEM adoption.

317. The overall growth rate of billing exceptions between 2014 to 2017 was approximately 1 percent.

318. SCE was able to address the 2018 spike in billing exceptions with significantly fewer staff than SCE proposes for the 2021 TY.

319. SCE's Billing FTE level was highest in 2016, which also had the lowest number of billing exceptions, while 2017 and 2018 had relatively fewer FTEs but a higher number of billing exceptions.

320. SCE has not established that the current level of FTEs is insufficient to address the current billing exception workload.

321. In D.19-05-020 the Commission disallowed SCE's request for Policy Adjustments, finding that "SCE has not established that ratepayers should pay for its errors."

322. In requesting Policy Adjustments in this proceeding, SCE does not address why ratepayers should pay for SCE's errors.

323. SCE's TY O&M forecast for Postage Expense includes associated savings from SCE's proposed AIM Initiative.

324. If SCE's proposed AIM Initiative is rejected, it is reasonable to remove SCE's projected savings from SCE's Postage Expense forecast.

325. SCE's unopposed TY O&M forecast for Postage Expense forecast is reasonable.

326. In response to arguments by Cal Advocates, TURN, and NDC, SCE revised its TY O&M forecast for Credit and Payment Services to include a \$0.2 million reduction reflecting the closure of 11 Rural Offices, an \$8,000 reduction reflecting a corrected customer growth rate (*i.e.*, 0.65 percent) in SCE's work volume calculation, and a reduction of \$0.668 million to correct an error with regards to CheckFreePay Services in SCE's non-labor forecast.

327. Beyond a general statement that SCE anticipates volume changes between work functions, SCE provides no actual evidence, or explanation of the underlying drivers, to support a 4 percent increase in the AHT of processing volume of work for Credit and Payment Services.

328. In this GRC SCE changes its historic labor forecast methodology for processing the volume of Credit and Payment Services work, using incoming work volume instead of completed work volume.

329. SCE's new Credit and Payment Services labor forecast methodology is based on limited 2018 data.

330. Customer adoption of electronic billing has, and continues to, steadily increase, while recorded labor costs for Credit and Payment Services have gradually declined between 2014 and 2018.

331. SCE's argument that it requires additional FTEs to address a backlog of Credit and Payment Services work is inconsistent with historical decreases in recorded labor and prior underspending of labor expenses, as well as general decreases in the average cost per payment.

332. SCE's uncontested Uncollectible Expenses factor is reasonable.

333. SCE currently operates paperless billing/self-service campaigns through a variety of media channels.

334. SCE does not propose to divert any of the existing paperless billing/self-service campaign funding towards its AIM Initiative.

335. SCE does not identify any cost reductions for its existing analytics and marketing labor costs as a result of the proposed AIM Initiative.

336. Almost 40 percent of SCE's proposed AIM funding is to update customer contacts.

337. SCE's PSPS outreach efforts already provide opportunities for customers located in HFRAs to update their contact information.

338. The economic uncertainties associated with the COVID-19 pandemic are ongoing.

339. Over this GRC period, SCE's AIM Initiative would cost ratepayers an annual net cost of \$1.856 million at a time when approximately 55 percent of SCE's customers are already expected to be enrolled in electronic billing by 2021.

340. SCE has not demonstrated that it considered all potential cost savings and existing programs/alternative revenue streams in its forecast methodology for the AIM Initiative.

341. SCE has not demonstrated that additional outreach efforts are necessary for customers located in HFRAs to update their contact information, and beyond the wildfire-related programs already in existence.

342. SCE has not presented convincing evidence that now is the appropriate time to fund the discretionary AIM Initiative.

343. SCE's proposed CPP funding is less than half of what was spent in previous years.

344. Customers defaulted to CPP have the option to opt-out of the program.

345. One of the media campaigns SCE cites to as being still needed (Summer Campaigns) is no longer running.

346. More than 20 percent of SCE customers speak English less than "very well."

347. SCE never addresses NDC's broader point that ACS data is only published every five years.

348. SCE's next GRC application is due in May of 2023.

349. SCE currently uses 2014-2018 ACS data that became available in 2019.

350. It is feasible that more current ACS data will not be available prior to SCE's next GRC filing.

351. SCE currently leverages CBOs and faith-based organizations to communicate to smaller ethnic groups.

352. NDC is an advocacy organization comprised of community-based, faith-based, and non-profit leaders.

353. SCE does not provide any cost estimates for the system modifications that would be required to collect participant demographic information at the Energy Centers.

354. SCE does not provide information on the direct costs incurred for each of the workshops and seminars held at the Energy Centers.

355. Providing a detailed, itemized breakdown of the expenditures incurred for seminars and workshops conducted by the Energy Centers would be administratively complex, and would require the manual collection of direct cost data across SCE.

356. SCE's uncontested TY O&M forecast for Escalated Complaints and Outreach is reasonable.

357. Tracking customer inquiries and complaints by language would provide SCE a means to gauge the effectiveness of its existing outreach to minority communities.

358. SCE does not provide evidence concerning the ability or cost limitations of the existing Sprout Social system in tracking customer inquiries and complaints by language.

359. NDC does not clearly explain how tracking individual social media channels (e.g., Facebook, Twitter, or Instagram) would yield better information than SCE's more aggregate tracking method (e.g., written, telephone, informal, and social media (in aggregate)) in determining "which customer groups primarily report complaints to the Consumer Affairs Organization."

360. SCE's uncontested TY O&M forecast for External Communications is reasonable.

361. SCE's uncontested TY O&M forecast for the CCC is reasonable.

362. SCE's TY O&M forecast for Business Account Management is based on 2018 recorded costs plus increases for account management/related support activities and outage communications activities.

363. SCE's 2018-2019 Business Account Management data indicates fewer overall account manager interactions and associated staffing needs.

364. The TE-related funding SCE is requesting in this GRC encompasses issues such as responding to customer questions regarding EV tariff provisions and rate options, service capacity, coordination with customers on outage management, meter installations, and providing education and support.

365. In D.20-08-045 the Commission authorized \$4.8 million to expand SCE's existing TE Advisory Services for commercial, government, small business, and fleet-operators.

366. SCE's existing TE Advisory Services range from initial awareness to TE training, hands-on-experience, TE-related assessments, and grant writing support.

367. SCE's existing TE Advisory Services covers similar types of activities to what SCE is requesting to fund in this GRC.

368. SCE's 2018-2023 DER forecast does not show significant incremental growth in either distributed generation or energy storage projects.

369. SCE's energy storage growth projections for 2020-2023 show annual incremental levels of energy storage installations that are below the recorded 2018 amount.

370. Cal Advocates and TURN do not provide any testimony, evidence, or explanation to support their recommendation to deny SCE's proposed increase for outage communications activities.

371. SCE sufficiently justifies its proposed adjustment for outage communications.

372. SCE's 2014-2018 data clearly shows significant, continual increases in all areas of online usage metrics.

373. SCE's proposed Digital Operations and Management projects are well defined and detailed, and would help support customer engagement and demand.

374. Due to limited resources, SCE only followed-up with 462 customers out of the 312,464 VOC surveys completed in 2019.

375. Approving two additional FTEs for CEM is likely to result in a more thorough and consistent analysis of customer comments moving forward.

376. Refresh data from outside vendors is used to ensure SCE has accurate customer data variables.

377. With the exception of SCE's request for a \$1.151 million increase for Hydraulic Services, SCE's TY O&M forecast for Business Account Management Services is uncontested.

378. The uncontested portions of SCE's TY O&M forecast for Business Account Management Services are reasonable.

379. In the past, funding for the Hydraulic Services activity has been split between the GRC and the EE balancing account.

380. SCE's 2021 EE budget request was made through SCE Advice Letters 4285-E and 4285-E-A, which were approved via an Energy Division Disposition letter dated December 28, 2020.

381. Advice Letters 4285-E and 4285-E-A propose to remove all costs for the Pump Test sub-program, also referred to as Hydraulic Services; these advice letters also indicate that the 2020 EE budget for Hydraulic Services was \$1.243 million.

382. The level of 2021 GRC funding is consistent with (and slightly below) SCE's 2020 EE budget for Hydraulic Services.

383. The 2019 Building Energy Efficiency Standards require all new low-rise residential buildings to include solar photovoltaic systems, effective January 1, 2020.

384. SCE's projected growth in NEM applications is largely based on the new solar photovoltaic requirement in the 2019 Building Energy Efficiency Standards.

385. No party challenged the accuracy of SCE's Solar Photovoltaic Forecast Model in this proceeding.

386. Given the new Building Energy Efficiency Standards requirement that low-rise residential buildings include solar photovoltaic systems, it is reasonable to expect some increase in NEM applications over historical levels.

387. Aside from SCE's adjustment to support additional NEM applications, SCE's TY O&M forecast for Customer Programs Management is uncontested.

388. The uncontested portions of SCE's Customer Programs Management O&M forecast are reasonable.

389. SCE's existing TE funding already includes significant marketing, education, and outreach initiatives to promote TE adoption.

390. SCE has not demonstrated how its GRC request for the general promotion of TE adoption leverages non-ratepayer funded TE ME&O activities.

391. The accounting treatment of SCE's O&M funding requests in this GRC are not clearly discernable from funding in SCE's TE proceedings.

392. SCE's unopposed 2019-2021 capital expenditure forecast for Customer Care Services Tools and Equipment is reasonable.

393. SCE presented, for the first time in its rebuttal testimony, the capital expenditure forecast for its IVR project.

394. It is unclear, based on the limited evidentiary record, the specific process by which SCE selected the certified IVR implementor for this project, or how the overall cost estimate compares with other quotes received.

395. The Commission rejected SCE's previous requests for ratepayer funding of service guarantees in SCE's 2006, 2009, 2012, 2015, and 2018 GRCs.

396. In D.04-07-022 the Commission established the Service Guarantee Program to ensure there is no degradation to SCE's current level of customer service.

397. SCE delivers on service guarantee standards an average of 99.1 percent of the time.

398. Except for SCE's proposed ratepayer funding of service guarantees, the remaining portions of SCE's Customer Interactions OOR forecast are uncontested.

399. The uncontested portions of SCE's Customer Interactions OOR forecast are reasonable.

Business Continuation

400. SCE's uncontested TY O&M forecast for Planning, Continuity, and Governance is reasonable.

401. Cal Advocates does not contest the merit of SCE's proposed activities for All Hazards Assessment, Mitigation and Analytics.

402. Beyond claiming that SCE's non-labor costs for All Hazards Assessment, Mitigation, and Analytics have fluctuated over the past eight years, Cal Advocates does not explain why 2019 forecast data is appropriate to smooth out past fluctuations for these activities, nor does Cal Advocates evaluate what is needed to accomplish the specific projects identified by SCE.

403. SCE's itemized non-labor forecast for All Hazards Assessment, Mitigation, and Analytics is well-supported and corresponds to the level of expenses SCE is likely to incur in 2021.

404. SCE's uncontested labor forecast for All Hazards Assessment, Mitigation, and Analytics is reasonable.

405. SCE's unopposed 2019 recorded and 2020-2021 forecast Climate Adaptation and Severe Weather Program capital expenditures are reasonable.

406. Parties do not dispute the general need and justification for SCE's planned seismic mitigation projects.

407. SCE's unopposed 2019 recorded and 2020-2021 capital expenditure forecasts for IT/Telecommunications Assets and Generation Infrastructure (within the Seismic Assessment & Mitigation Program) are reasonable.

408. Except for the Transmission Substation Mitigation sub-category, all other sub-categories in SCE's 2019-2021 Electric Infrastructure forecast are uncontested.

409. The uncontested sub-categories in SCE's 2019-2021 Electric Infrastructure forecast are reasonable.

410. In D.19-05-020 the Commission determined that the contingency amounts included in SCE's capitalized software project forecasts were not recoverable as a forecast item.

411. SCE argues in this proceeding that the application of a contingency factor is a standard practice that accounts for 'unforeseen conditions.'

412. While the nature and purpose of seismic retrofitting is distinct from capitalized software projects addressed in D.19-05-020, SCE provides the same underlying rationale to justify the application of a contingency factor in both forecasts.

413. SCE's Non-Electric Facilities forecast contains one large \$11 million office building with a cost per square foot that is significantly higher than the other projects included in SCE's forecast.

414. The large \$11 million office building is based on a forecasted amount, whereas all other projects included in the forecast are based on known, recorded costs.

415. SCE adjusts its forecast for the structural retrofitting of MEER buildings to account for certain costs that were excluded from the third-party engineering estimate.

416. Except for SCE's application of a contingency factor, the remaining adjustments SCE made to the third-party engineering estimate to structurally retrofit SCE's MEER buildings are adequately justified.

417. There is not a consistent, direct relationship between building size and the price per square foot for the previously completed retrofit projects SCE included in its Non-Electric Facilities forecast.

Emergency Management

418. SCE's unopposed TY O&M forecasts for Emergency Management are reasonable.

419. Storm events can vary significantly from year to year and are driven by factors outside of SCE's control.

420. SCE's 2019-2021 capital expenditure forecast for Emergency Management is based on a five-year average of recorded expenditures to account for year-to-year variations.

421. SCE initially forecast \$46.534 million and \$47.953 million in Emergency Management capital expenditures for 2020-2021.

422. SCE's requested Emergency Management capital expenditure amounts were subsequently adjusted, without explanation, to \$49.951 million and \$51.174 million in 2020-2021, then adjusted again to \$56.401 million and \$58.118 million in 2020-2021.

Cybersecurity

423. SCE has provided adequate justification for the unopposed Cybersecurity O&M forecasts: Grid Modernization Cybersecurity and Software License and Maintenance.

424. SCE has failed to adequately justify its requested increases to the labor and non-labor forecasts for Cybersecurity Delivery and IT Compliance.

425. Cal Advocates' proposed Cybersecurity Delivery and IT Compliance labor and non-labor forecasts still provide some increase above 2018 base costs and are reasonable.

426. SCE has provided adequate justification for its 2020-2021 Cybersecurity capital expenditure forecasts.

427. Consistent with treatment of 2019 capital expenditures for other BPEs, it is reasonable to adopt SCE's recorded 2019 Cybersecurity capital expenditures.

Physical Security

428. SCE has provided adequate justification for its Physical Security O&M forecasts.

429. SCE has provided adequate justification for its 2019 recorded and 2020-2021 forecast Physical Security capital expenditures.

Generation

430. SCE's adjusted TY Hydro O&M forecast, which includes adjustments to non-labor costs for operating the retired Borel plant and labor costs to account for incorrect timecard entries, is reasonable.

431. SCE's 2019-2021 forecast for hydro capital expenditures is unopposed with the exception of its forecast for the San Gorgonio hydro facility decommissioning project.

432. SCE's unopposed 2019-2021 forecast hydro capital expenditures are reasonable.

433. SCE has submitted the same scope of work for the San Gorgonio hydro facility decommissioning project in five consecutive GRCs, including this GRC.

434. The failure to start full-scale decommissioning of San Gorgonio is due to events beyond SCE's control.

435. A permanent disallowance of SCE's projected costs for San Gorgonio decommissioning is not justified; however, SCE has failed to justify its proposed decommissioning costs for this GRC cycle.

436. It is reasonable to approve \$0.408 million annually for the San Gorgonio project in order for SCE to address ongoing safety, regulatory, and other requirements during this GRC cycle.

437. Consistent with treatment of 2019 capital expenditures for other BPEs, it is reasonable to adopt the recorded 2019 capital expenditures for the San Gorgonio project.

438. SCE's adjusted TY O&M and 2019-2021 capital expenditure forecasts for Mountainview, which incorporate adjustments proposed by TURN, are reasonable.

439. SCE's unopposed TY O&M and 2019-2021 capital expenditure forecasts for its solar generating plants are reasonable.

440. SCE's adjusted TY O&M forecast for its fuel cell generating plants, which incorporates an adjustment proposed by TURN, is reasonable.

441. SCE's adjusted TY O&M forecast for its Catalina Generation units, which incorporates an adjustment proposed by TURN, is reasonable.

442. SCE's unopposed 2019 recorded costs for Catalina-related capital expenditures, and 2020-2021 forecast capital expenditures for the Pebbly Beach Generation Station resurface paving project, are reasonable.

443. The details for SCE's proposed Catalina Repower project have changed during the pendency of this proceeding.

444. Due to uncertainty regarding the scope and timing of the Catalina Repower project, additional review of the project is warranted prior to approving funding for 2020 and 2021.

445. SCE's unopposed TY labor forecast for Palo Verde O&M is reasonable.

446. It is reasonable to use the most up to date budget information from Arizona Public Service in the record for the TY non-labor forecast for Palo Verde O&M.

447. TURN's recommended reduction to SCE's TY non-labor forecast for Palo Verde O&M is reasonable.

448. The Commission has consistently removed half of the costs for NEI dues in recent GRC cases, recognizing the organization's dual role of promoting nuclear power through public relations and lobbying, while also working to cut industry costs.

449. SCE has failed to provide additional information that would justify a departure from the Commission's past treatment for NEI dues.

450. It is reasonable to continue to authorize ratepayer funding of 50 percent of SCE's shares of the NEI dues.

451. After responding to a data request from TURN, SCE became aware that the established accounting was incorrectly netting Palo Verde water sale

revenues against O&M expenses, resulting in the Gross Incremental Revenues not being shared with customers.

452. SCE's unopposed 2019-2021 capital expenditure forecast for Palo Verde is reasonable.

453. SCE's unopposed TY O&M and 2019-2021 capital expenditure forecasts for its Peaker plants are reasonable.

Energy Procurement

454. In the decision on SCE's 2021 ERRRA Forecast Application, D.20-12-035, the Commission approved SCE's proposals to recover certain non-labor expenses originally included in SCE's Energy Procurement TY O&M forecast (CARB fees, subscription costs, and consulting fees) through non-GRC recovery mechanisms.

455. SCE's TY O&M Energy Procurement forecast less the costs D.20-12-035 approved for recovery through non-GRC recovery mechanisms is unopposed and reasonable.

456. SCE's unopposed 2019 recorded and 2020-2021 forecast Energy Procurement capital expenditures are reasonable.

Enterprise Technology

457. SCE's Enterprise Technology TY O&M forecasts are adequately justified and reasonable.

458. Due to the delay in CSRP implementation, Software Maintenance and Replacement O&M costs originally forecast for 2021 have been deferred to 2022 and 2023.

459. It is reasonable for SCE's TY O&M forecast for Software Maintenance and Replacement to reflect a normalization adjustment to account for the expected cost increases in 2022 and 2023.

460. SCE's unopposed 2019 recorded and 2020-2021 forecast Enterprise Technology capital expenditures are reasonable.

OU Capitalized Software

461. SCE's unopposed 2019 recorded and 2020-2021 forecast OU Capitalized Software expenditures are reasonable.

462. SCE has provided adequate justification for the recorded 2017 and 2018 capitalized software project costs that were above authorized amounts, and no party disputes the reasonableness of these costs.

Enterprise Planning and Governance (Non-Insurance)

463. SCE's adjusted TY O&M forecast for Financial Oversight and Transactional Processing incorporates adjustments proposed by Cal Advocates to: (1) Vendor Discount and Other Miscellaneous Payments and (2) Participant Credits and Charges.

464. SCE's adjusted TY O&M forecast for Financial Oversight and Transactional Processing is unopposed with the exception of its forecast for Accounting, Financial Compliance, and Financial Reporting.

465. SCE's unopposed TY O&M forecasts for Financial Oversight and Transactional Processing are reasonable.

466. SCE's TY O&M forecast for Accounting, Financial Compliance, and Financial Reporting based on 2018 recorded costs plus adjustments is reasonable when taking into account historical spending levels and the reasons presented for the lower 2018 recorded costs.

467. SCE's cost savings through Operational Excellence initiatives were fully materialized in 2017, and therefore, SCE's lower 2018 Accounting, Financial Compliance, and Financial Reporting costs are not attributable to Operational Excellence initiatives.

468. An accounting change that created a one-time timing difference in expense recording resulted in 2018 Accounting, Financial Compliance, and Financial Reporting expenses being lower and 2019 expenses being higher than historical average spending levels.

469. SCE explains that the lower Accounting, Financial Compliance, and Financial Reporting labor costs it experienced in 2018 compared to 2017 were due to temporary unexpected employee turnover in 2018.

470. SCE's requested Accounting, Financial Compliance, and Financial Reporting labor costs for the TY are \$0.3 million lower than 2017 recorded costs and represent a 12 percent reduction compared to historical average spending from 2014-2018.

471. SCE's requested Accounting, Financial Compliance, and Financial Reporting non-labor costs for the TY are \$1.2 million lower than 2017 recorded costs and represent a 3 percent reduction compared to historical average spend from 2014-2018.

472. SCE's unopposed TY O&M forecast for its Legal organization and activities is reasonable.

473. SCE's unopposed TY O&M and 2019-2021 capital expenditure forecasts for Business and Financial Planning are reasonable.

474. SCE's unopposed TY O&M forecast for Mailing Services and Graphics Production is reasonable.

475. SCE has not adequately justified its requested increase in SDD labor expense to revert to a staffing level of nine FTEs, but provided adequate justification for an additional FTE to focus on small businesses.

476. SDD has been able to sustain its performance level even when it did not have nine FTEs for extended periods of time.

477. Especially given the additional challenges facing small businesses due to the COVID-19 pandemic, it is reasonable for SCE to add a position within SDD focused on small business programming and outreach.

478. Recorded 2018 costs would be insufficient to account for the additional small business position within SDD.

479. A TY O&M labor forecast for SDD based on 2018 recorded costs of \$0.980 million, plus an increase of \$97,000 to account for an additional small business position is reasonable.

480. SCE's TY O&M non-labor forecast for SDD is reasonable.

481. SCE's unopposed 2019-2021 capital expenditure forecast for Supply Chain Management is reasonable.

Insurance

482. Consistent with prior years, SCE continues to purchase approximately \$1 billion of wildfire liability insurance coverage.

483. It is prudent for SCE to maintain \$1 billion in wildfire liability coverage since that is the level of liability SCE would need to incur before accessing the Wildfire Fund created by AB 1054.

484. Liability insurance is a standard cost of doing business that is primarily designed to benefit ratepayers.

485. It is not reasonable to change the traditional cost allocation framework for wildfire liability insurance costs based on the risk that SCE's future actions could be found to be imprudent.

486. All three major energy utilities operate under the same cost allocation framework for wildfire liability costs, including the cost allocation framework set forth in AB 1054.

487. TURN and Cal Advocates do not provide a compelling justification to depart from Commission precedent regarding ratepayer/shareholder allocation of wildfire liability insurance costs.

488. SCE's TY wildfire liability insurance forecast of \$623.8 million developed by its primary insurance broker, Marsh USA Inc., is a significant increase from previously authorized and recorded costs.

489. Although the Commission has adopted insurance expense forecasts developed by SCE's broker in the past, SCE's showing with respect to its wildfire liability insurance forecast is inadequate given the magnitude of the request.

490. Given the difficulties in accurately forecasting wildfire liability insurance costs and the lack of justification for SCE's forecast, it is reasonable to adopt a TY forecast of \$460 million based on amounts the Commission has found to be reasonable and authorized for 2020.

491. SCE has not set forth any specific proposal for alternative risk transfer instruments for the Commission's review, and therefore, we cannot make a finding that SCE's use or potential use of any alternative risk transfer instrument is reasonable.

492. Under certain circumstances, alternative risk transfer instruments may be a more cost-effective way to manage risk.

493. The use of alternative risk transfer instruments is not novel.

494. There is no evidence that SCE's insurance broker systematically overestimates SCE's non-wildfire liability or property insurance forecasts.

495. SCE's non-wildfire liability and property insurance forecasts based on its insurance broker's projections are reasonable.

496. SCE does not provide a compelling justification for accelerating recovery of its wildfire insurance-related regulatory asset.

Employee Benefits and Programs

497. SCE's following Employee Benefits and Programs TY forecasts are unopposed: the 401K Savings Plan, Dental Plans, Disability Management - Administration, Disability Management - Programs, Group Life Insurance, Medical Programs, Miscellaneous Benefit Programs, PBOP Costs (Non-Service), PBOP Costs (Service), Pension Costs (Non-Service), Pension Costs (Service), Severance, and the Vision Service Plan.

498. SCE's unopposed TY forecasts for Employee Benefits and Programs are reasonable subject to SCE excluding executive compensation costs consistent with our determinations in this decision and making any necessary modifications based on the final total labor forecast.

499. Given the volatility in the forecasts for Pension costs, PBOP costs (excluding actuarial fees), Medical Programs, Dental Plans, and the Vision Plan, SCE's unopposed requests to continue two-way balancing account treatment for these costs are reasonable.

500. Prior to SB 901, the authorized revenue requirement for electrical and gas corporations included ratepayer funding for officer compensation.

501. In Resolution E-4963, the Commission directed electric utilities to establish memorandum accounts so that rates authorized in pre-SB 901 rate cases could be refunded in future proceedings without violating the prohibition on retroactive ratemaking.

502. Resolution E-4963 made the finding that: "The term 'officer' means those employees of the investor owned utilities in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act."

503. There is no compelling reason why all executives at the level of VP and above should be deemed an “officer” for purposes of Section 706.

504. There is a reasonable basis for drawing a distinction between the treatment of compensation for Rule 3b-7 officers and other executives and employees.

505. Unlike other executives and employees, Rule 3b-7 officers are senior-level management, responsible for policy decisions of the company, and directly answerable to SCE’s Board of Directors.

506. In the absence of a clear definition of “officer” in SB 901, a clear statement of legislative intent with respect to the statute, or a reasoned basis for an alternative definition, it is reasonable to continue to apply the definition of “officer” adopted in Resolution E-4963.

507. The five executives who are dual officers of both SCE and EIX are employees of SCE for part of the year.

508. Of the five shared officers, SCE allocates 99 percent of the position to SCE for four shared officers and 70 percent of the position to SCE for one shared officer.

509. EIX is not an electrical or gas corporation.

510. Cal Advocates’ recommendation that ratepayers fund no more than 50 percent of SCE’s Executive Benefits forecast is justified and consistent with Commission precedent.

511. In past GRCs, the Commission has allowed rate recovery of 50 percent of SCE’s Executive Benefits forecast because Executive Benefits are based, in part, on executive bonuses, not all of which are recoverable in rates.

512. In past GRCs, the Commission has found that Executive Benefits costs should be equally shared between ratepayers and shareholders because both receive benefits from the retention of executives and managers.

513. The Commission's rationale for reducing recovery of Executive Benefits by 50 percent in past GRCs continues to apply in this GRC.

514. Going back to at least the 2009 GRC, the Commission has excluded SCE's LTI costs from rates because LTI does not align executives' interests with ratepayer interests.

515. SCE does not present any new arguments that would warrant a departure from the Commission's longstanding policy to exclude LTI costs from rates.

516. LTI is primarily designed to reward SCE employees for promoting shareholder interests.

517. SCE's STIP includes the following plans: (1) the Short-Term Incentive Plan for non-executives, (2) the KCIP for limited non-executives, and (3) the EIC for those executives who are not officers (less than one percent of the employee population).

518. Offering employee compensation in the form of incentive payments is useful for recruiting and retaining skilled professionals and improving work performance and is a generally accepted compensation practice.

519. The sharing of cost responsibility for incentive compensation promotes a reasonable matching of costs with benefits experienced both by ratepayers and shareholders.

520. It is within SCE management's discretion to target incentive compensation to achieve ratepayer benefits.

521. SCE has not justified an increase in STIP costs beyond historical levels.

522. Consistent with past GRCs, it is reasonable to limit ratepayer funding of STIP based on the historical ratio of STIP to total labor expenses.

523. The 12.11 percent STIP to labor ratio initially adopted in 2015 is based on the six year-average from 2008-2013, which is outdated.

524. It is reasonable to adopt a STIP to labor ratio of 16.10 percent based on a five-year (2014-2018) average, which excludes costs for the KCIP plan and the Augment Plan.

525. It is reasonable to exclude 2019 data when determining the STIP to labor ratio because SCE indicates the 2019 data is based on preliminary unadjusted data and the Total Compensation Study is based on 2018 recorded costs and does not provide any analysis as to whether the 2019 costs are at market.

526. It is reasonable to exclude the recorded costs for KCIP and the Augment Plan when determining the STIP to labor ratio because SCE has failed to demonstrate the reasonableness of ratepayer funding for its KCIP program.

527. SCE explains that KCIP payouts are based on manager discretion and not based on any specific metrics.

528. Based on the information provided by SCE, it is unclear whether the KCIP program aligns with ratepayer interests.

529. It is reasonable to continue to exclude costs associated with the STIP/EIC goals that primarily benefit shareholders.

530. SCE has failed to demonstrate that costs related to the Financial Performance STIP goal category (weighted at 30 percent of STIP goals) are reasonable.

531. The Financial Performance goal is primarily intended to benefit shareholders.

532. The Financial Performance goal may or may not result in secondary benefits to ratepayers since a goal of "achieving core earnings" does not always align shareholder and ratepayer interests.

533. SCE has failed to demonstrate that STIP costs associated with policy shaping goals are reasonable.

534. Approximately 20 percent of SCE's STIP goals are related to policy shaping goals: (1) "Shape California legislative and regulatory policies to align with SCE's strategy" within the Policy, Growth and Innovation goal category (9 percent); and (2) "Policy Reform, Wildfire" within the Wildfire Resiliency goal (11 percent).

535. STIP payout criteria that are based on achieving decisions in CPUC proceedings (GRC, cost of capital) with certain outcomes and achieving specified policy objectives are directly related to shareholder benefits and may or may not provide secondary benefits to ratepayers.

536. The additional sharing of STIP program costs between shareholders and ratepayers beyond what is ordered in this decision is not justified.

537. SCE's Spot Awards recognize an individual or team for delivering exceptional, measurable results, such as making significant contributions to public or employee safety, significantly improving efficiency across one or more Operating Units, and leading a Company-wide team or major project that notably exceeds expectations within scheduled time frames and under budget.

538. SCE's Encore Awards recognize workers for their achievements to help transform the company's safety culture.

539. The types of behaviors (*e.g.*, a focus on safety) that SCE's recognition programs reward further the provision of safe and reliable service at just and reasonable rates.

540. SCE's recognition program costs are reasonable relative to the benefits.

541. Companies commonly use recognition programs and SCE's budget is in line with those used by the majority of organizations for such programs.

542. Given that SCE's recognition program budget is 0.15 percent of labor, inclusion of these program costs would not have a material impact on SCE's total

compensation levels, which the Total Compensation Study estimates are below market by 3.0 percent with a degree of accuracy of plus or minus 5 percent.

Employee Training and Support

543. SCE's unopposed Employee Training TY forecast of \$63.796 million is reasonable.

544. SCE's uncontested total Employee Support TY forecast of \$40.458 million, which reflects adjustments recommended by TURN, is reasonable.

Environmental Services

545. SCE's uncontested TY O&M forecast for Environmental Services is reasonable.

546. SCE's uncontested 2019-2021 capital expenditures for Well Decommissioning and Programmatic Permits are reasonable.

547. Given the significant capital expenditures we approve in this decision for pole maintenance, repair, and replacement via programs such as the Pole Loading Program, Deteriorated Pole Program, and Aerial Inspection Maintenance Program, SCE fails to adequately justify the need for additional funding for pole retrofits through its new proposed Avian Retrofits program to ensure safety and reliability.

Audit Services

548. SCE provided a privilege log listing 13 privileged audits for 2018 totaling \$730,521.

549. With the exception of the audit for "Third Party Review," the expenses for the audits listed in SCE's privilege log appear to be reasonable business expenses and are reasonable to include for purposes of determining the TY forecast.

550. The information provided in SCE's privilege log regarding the Third Party Review audit is too vague and general for the Commission to determine whether the expenses are reasonably assigned to ratepayers.

551. SCE's TY O&M forecast for Audit Services less the costs for the Third Party Review audit (\$150,863) is reasonable.

Ethics and Compliance

552. SCE's uncontested TY O&M forecast for Ethics and Compliance work is reasonable.

Safety Programs

553. SCE's uncontested TY O&M forecast for the Safety Programs BPE is reasonable.

Enterprise Operations

554. SCE's unopposed TY O&M forecast for Enterprise Operations is reasonable.

555. SCE's unopposed 2019 recorded and 2020-2021 forecast Transportation Services capital expenditures are reasonable.

556. The Facility and Land Operations BPE is comprised of Infrastructure Upgrades, Facility Repurpose Programs, Substation Reliability Upgrades, Facility Management Capital Programs, and Land Operations.

557. SCE's 2019 recorded and 2020-2021 capital expenditure forecasts for Facility Repurpose Programs, Facility Management Capital Programs, and Land Operations are uncontested.

558. SCE's uncontested forecasts for the Facilities and Land Operations BPE are reasonable.

559. With the acceptance of TURN's proposed \$2.054 million reduction, SCE's revised forecast for the Blythe Service Center is uncontested.

560. In D.19-05-020, the Commission found that SCE justified its proposal to relocate its Santa Barbara Service Center on the basis that the reduction in employee travel time would result in the dual benefits of shorter outages in the Santa Barbara area, as well as higher retention rates for SCE's employees.

561. D.19-05-020 also states that in the event SCE diverts funds from the Santa Barbara Service Center Relocation project, the Commission will consider whether the financial responsibility for this project should be placed on SCE's shareholders.

562. SCE demonstrates it has been actively engaged in finding a site to relocate the Santa Barbara Service Center, while many of the project delays appear to be outside of SCE's control.

563. There are unique challenges in locating a suitable parcel to relocate the Santa Barbara Service Center.

564. SCE has not provided assurances that it is any closer to securing a site for the Santa Barbara Service Center, only stating that it "continues to work with a local broker to identify a parcel suitable for sustaining service center operations."

565. The need for the T&D Training Center, Vehicle Maintenance Facilities, and the Devers and Rector Maintenance and Test Buildings is undisputed.

566. SCE has secured a site for the new T&D Training Center and has commenced planning and engineering work for the project.

567. The new T&D Training Center would provide sufficient classroom and outdoor space to eliminate existing weekend and swing shift classes arising from space and equipment constraints.

568. The cost information provided by CCMI for the new T&D Training Center is sufficiently detailed and supported.

569. SCE's Vehicle Maintenance Facilities project would renovate three vehicle maintenance facilities that are heavily used, over 30 years old, and that do not accommodate the size and weight of the newer T&D trucks.

570. The delays associated with the Vehicle Maintenance Facilities project have been entirely within SCE's control, and SCE did not record any expenditures for the project as of the end of 2019.

571. The Devers and Rector Substations account for two of the three substations with the highest FCI Scores.

572. SCE has reasonably justified the need for the Santa Barbara Service Center, T&D Training Center, Devers and Rector Maintenance and Test Buildings, and Vehicle Maintenance Facilities projects.

573. SCE has demonstrated continual progress on both the Devers and Rector Substation projects, including recorded expenditures from 2016 through the present and significant project construction.

574. CCM's cost estimates for the Devers and Rector Maintenance and Test Buildings are sufficiently detailed and supported.

Policy and External Engagement

575. SCE's uncontested TY O&M forecast for the Education, Safety, and Operations activity is reasonable.

576. It is reasonable to exclude \$92,262 from SCE's 2018 recorded non-labor expenses for Develop and Manage Policy and Initiative activities that are non-recurring costs.

577. For the purposes of determining the TY forecast, it is reasonable to include costs for services related to the examination of regulatory and legislative issues associated with the growth of CCA and its impacts on the utilities and utility

customers in the 2018 recorded non-labor expenses for Develop and Manage Policy and Initiative activities.

578. SCE has failed to provide adequate justification for an increase above last year recorded costs for Develop and Manage Policy and Initiative activities.

579. SCE's aggregate O&M expenses for Develop and Manage Policy and Initiative activities have declined by 29 percent between 2014-2018 and have declined each year for the past 3 recorded years.

580. It is reasonable to approve a TY O&M forecast for Develop and Manage Policy and Initiative activities based on last year recorded costs.

581. SCE has presented sufficient evidence demonstrating that ratepayers receive some benefits from EEI membership.

582. In the past, the Commission has specifically barred ratepayer funding of EEI membership activities such as: legislative advocacy, legislative policy research, regulatory advocacy, advertising, marketing, and public relations.

583. SCE does not provide a breakdown of EEI's membership activities or dues that would enable the Commission to determine how much of the dues are attributable to activities the Commission has previously deemed improper for ratepayer recovery.

584. SCE relies on information presented in the EEI invoice to exclude costs related to "influencing legislation," but the invoice does not present an itemized breakdown of other activities that the Commission has previously excluded from ratepayer funding.

585. Given SCE's demonstration that there are some ratepayer benefits, it is reasonable to approve some ratepayer funding for SCE's EEI membership dues.

586. It is reasonable to approve EEI dues designated for the Restoration, Operations, and Crisis Management Program (\$0.015 million).

587. Based on amounts the Commission has previously found to be reasonable, it is reasonable to approve ratepayer funding for 50 percent of the remainder of the EEI dues (\$0.968 million).

588. SCE's uncontested dues and memberships totaling \$0.211 million for the Professional Development and GRC activity are reasonable.

Pricing and Ratemaking

589. SCE's uncontested TY O&M forecast for the Pricing and Ratemaking BPE is reasonable in light of SCE's historical costs for 2014-2018.

GRC-Related Balancing and Memorandum Accounts

590. SCE's unopposed request to transfer the December 31, 2020 balance in the ECPMA to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels is reasonable.

591. SCE unopposed request to transfer the ending December 31, 2020 IDERACMA and DDACMA balances, including accrued interest, to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels is reasonable.

592. SCE's uncontested proposal to eliminate the ACESBA is adequately justified.

593. SCE's unopposed request to continue the RRIMA until the end of the 2021 GRC cycle is adequately justified.

594. SCE's uncontested proposal to remove recovery of cooling center costs from Preliminary Statement Part AA, CARE is consistent with Commission direction in D.16-11-022 that these costs be included in the GRC forecast.

595. SCE's uncontested request to establish the ZFMA to track costs associated with Z-Factor events is reasonable.

596. SCE unopposed request to continue the two-way PBOPBA through the 2021 GRC cycle to record the difference between authorized and actual PBOP expenses is reasonable.

597. SCE unopposed request to continue the two-way PCBA through the 2021 GRC cycle to record the difference between authorized and actual pension expenses is reasonable.

598. SCE's unopposed request to continue the two-way MPBA through the 2021 GRC cycle to record the difference between authorized and actual medical, dental, and vision expenses is reasonable.

599. SCE unopposed request to continue the one-way STIPMA through the 2021 GRC cycle to record the difference between authorized and actual STIP expenses is reasonable.

Other Ratemaking Proposals

600. SCE's unopposed request to recover mobilehome park pilot program costs of \$136.0 million, consisting of approximately \$133.6 million in capital expenditures and \$2.4 million in O&M expense, is reasonable.

Other Operating Revenue (OOR)

601. SCE's uncontested forecast of \$29.688 million for Financial and Other Miscellaneous Revenue in Account 456 is reasonable.

602. SCE's uncontested forecast of \$1.034 million in revenues for gains and losses on sale of property is reasonable.

603. SCE's OOR forecast of \$16.672 million for revenues generated from NTP&S is consistent with the previously authorized GRSM threshold.

604. In D.97-12-088, as modified by D.06-12-029, the Commission adopted rules governing Affiliate Transactions and determined that all incremental costs for NTP&S are the sole responsibility of utility shareholders.

605. TURN's recommendations that SCE keep a record of each of the "but for" tests it conducts for its NTP&S offerings, and that SCE keep time logs and other appropriate records concerning NTP&S offerings' use of ratepayer funded utility resources, were presented for the first time in TURN's opening brief.

606. SCE was not afforded the opportunity to address in testimony or hearings the potential cost and resource impacts necessary to implement TURN's NTP&S recommendations.

607. TURN fails to provide any actual evidence concerning the type and level of SCE resources used by NTP&S offerings other than ECS.

608. SCE has provided sufficient evidentiary basis to support its claim that SCE has established accounting procedures and processes to identify and record incremental costs associated with NTP&S.

609. There is no evidence in this proceeding that utility service costs used to support NTP&S offerings have been improperly allocated.

610. There is a limited record concerning TURN's recommendations for SCE to keep a record of each of the "but for" tests it conducts for its NTP&S offerings, and to keep time logs and other appropriate records concerning NTP&S offerings' use of ratepayer funded utility resources.

611. SCE raises legitimate concerns regarding whether TURN's recommendations would be unduly costly and administratively burdensome.

612. TURN's NTP&S recommendations are more appropriately limited to ECS. It is reasonable to expect SCE's NTP&S processes, which include annual trainings with shared service partners, to help limit instances where incremental costs are not properly identified.

613. The Commission is not precluded from making ongoing improvements to SCE's established NTP&S accounting procedures.

614. The revenue generated from Added Facilities is included in OOR and acts as an offset to the Added Facilities' costs included in the revenue requirement.

615. SCE may either finance Added Facilities or require the customer to finance Added Facilities.

616. SCE's longstanding methodology for calculating Added Facilities rates is based on portfolio-derived levelized rates.

617. SCE's methodology for calculating Added Facilities rates is consistent with cost-of-service ratemaking.

618. SCE's portfolio-derived levelized rate ensures that SCE can recover the return of its portfolio of Added Facilities investments.

619. SCE's depreciation accruals include costs of removal, and therefore, the fact that the accumulated depreciation may exceed the investment base does not demonstrate that SCE has over-collected costs.

620. The schedules of SCE-financed Added Facilities relied on by EPUC reflect incomplete data.

621. Ceasing cost recovery after an individual Added Facilities asset (rather than the portfolio) has reached full cost recovery, as proposed by EPUC, would result in shortfalls that would need to be subsidized by other customers.

622. Since SCE does not separately track accumulated depreciation for each Added Facilities asset, it is likely infeasible to determine the specific accruals for each asset, which would be required to implement EPUC's proposals.

623. There is a lack of justification to require SCE to deviate from traditional group accounting practices to separately track depreciation accruals for Added Facilities assets in the future, or develop individualized rate options for each of its approximately 900 active SCE-financed Added Facilities customers.

624. Added Facilities customers have the option to choose the customer-financed option if the SCE-financed options are not agreeable to them.

625. There is no evidence there are barriers that would restrict Added Facilities customers from obtaining their own competitively priced financing.

626. SCE's use of a five-year (2014-2018) average to forecast revenues for SCE-financed facilities and last-year recorded (2018) costs to forecast revenues for customer-financed facilities is reasonable.

627. SCE's uncontested proposals for addressing terminated or terminating Added Facilities contracts with 20-year terms are reasonable.

Rate Base

628. In 2013, SCE initiated an aged pole program that replaced poles over a certain age regardless of their condition.

629. In the 2015 GRC, the Commission found that SCE failed to demonstrate that the aged pole replacements were prudent at the level requested and disallowed a substantial portion of the costs associated with the program, permitting SCE to add to rate base the costs of the pole replacements for 2013, a portion of those for 2014, and none for 2015.

630. SCE has not presented evidence that supports a finding that it would have been prudent to replace the previously disallowed poles replaced in 2014 and 2015 during this GRC cycle.

631. The poles replaced through the aged pole program in 2014 and 2015 would have continued to be useful at least through 2024-2025, on average, or longer.

632. SCE's PVR analysis does not demonstrate the prudence of the investment or the reasonableness of including the poles replaced in 2014 and 2015 through the aged pole program in rates for this GRC cycle.

633. The Commission's reliance on PVRR calculations in the 2018 GRC with respect to the pole loading program was not for the purpose of determining the prudence of the investment or the appropriate duration of a disallowance.

634. Given the variability in recorded fuel and purchased power lag days, it is reasonable to base the forecast on four years of recorded data rather than relying solely on 2018 recorded data.

635. Cal Advocates' recommendation to use a 4-year simple moving average to forecast fuel and purchased power lag days ignores the dollar impact in each year and distorts the weighting of the actual transactions.

636. SCE's alternative proposal to use a 4-year average based on dollar-weighted payment amounts to forecast fuel and purchased power lag days is reasonable.

637. Cal Advocates' recommendation to update SCE's fuel and purchased power forecast from Spring 2019 to Fall 2019 is reasonable.

638. Cal Advocates recommends forecasting lag days for Wildfire Insurance Premiums by taking a simple average of the weighted average lag day results from each year between 2017-2019.

639. Cal Advocates' proposed methodology for forecasting lag days for Wildfire Insurance Premiums does not take into account the weighting of the actual transaction and underweights the more recently experienced data.

640. Over half of SCE's recorded payments for Wildfire Insurance Premiums are from 2019.

641. SCE's forecast of -186.9 lag days for Wildfire Insurance Premiums, based on using all available recorded data from 2017-2019, to determine the dollar-weighted average payment lag days is reasonable.

642. SCE's lead-lag proposal for Goods and Services is a composite total of 37.3 lag days based on the dollar-weighted average payment lag days for PO transactions (40.2 days) and non-PO transactions (11.7 days).

643. SCE's proposed 40.2 lag days for PO orders is not reasonable.

644. SCE fails to explain why expedited payments to DBEs would justify lag days 7.7 to 11.7 days shorter than what SCE has been able to achieve in the past when payments to DBEs made up 47 percent of SCE's spending in 2018 and, on average, were only 3 days faster than payments to non-DBEs.

645. SCE's recorded PO lag days and vendor discounts indicate that the level of vendor discounts is not necessarily negatively impacted by targeting higher PO payment lag days.

646. SCE could account for the faster processing time of electronic payments (compared to check payments) when determining the timing of electronic payments.

647. TURN's proposal of 45 lag days for PO transactions is reasonable and consistent with best cash management practices.

648. SCE's uncontested proposal of 11.7 lag days for non-PO transactions is reasonable.

649. SCE reduces rate base at the same time that depreciation expense is accrued at the midpoint of the service period.

650. It is undisputed that there is a 45.1-day revenue lag between when the depreciation expense is recorded (and rate base reduced) and when revenue is received from the customer.

651. TURN's recommended depreciation expense lag of 15.2 days would result in a 15.2-day gap during which rate base has been lowered but the

corresponding depreciation expense has not yet been received from the customer.

652. It is reasonable to continue the longstanding practice of compensating for depreciation expense lag such that rate base is kept whole until payment is received from the customer.

653. SCE's proposed 0-day lag for depreciation expense is reasonable.

654. Due to net operating loss and other tax credit carryovers, SCE has not had federal taxes due since 2009 and California taxes due since 2016.

655. SCE uses its five-year (2005-2009) tax payment history to forecast the federal income tax lag and its five-year (2011-2016) tax payment history to forecast the state income tax lag.

656. The purpose of calculating income tax lag days is to make appropriate adjustments to the working cash requirement, which is intended to ensure that the utility has sufficient cash for day-to-day operational requirements.

657. SCE's forecasted lag days for state and federal income taxes are not reasonable because SCE fails to demonstrate that they are likely to be representative of the lag days for the test year.

658. SCE fails to justify going back to tax payment history for 2005-2009 and 2011-2016 to forecast income tax lag days for 2021.

659. SCE generally agrees that it has incurred significant deductible tax costs over the past 10 years and that the deductibility of potential wildfire obligations could limit federal or state tax liabilities for the next few years.

660. Given that SCE has not paid federal income taxes for several GRC cycles and state income taxes since before the last GRC cycle, and given the lack of evidence that SCE's tax situation is likely to change for this GRC cycle, TURN's

proposal to use 365 lag days for both state and federal taxes is reasonable for purposes of calculating the appropriate expense lag adjustment to working cash.

661. In every GRC since 2003, the Commission has required SCE to offset rate base by the amount of its CDs as an adjustment for working cash.

662. Beginning with SCE's 2012 GRC, the Commission has granted SCE permission to use up to 10 percent of its CDs to promote the Company's use of minority and community banks.

663. The CDs housed in SCE's minority and community bank program are not included as an offset to rate base.

664. It is reasonable to continue the policy of requiring SCE to use CDs to offset rate base.

665. CDs have continued to act as a substantial source of permanent low-cost working capital for SCE.

666. SCE does not segregate the cash associated with CDs from all other sources of available operating funds or working cash other than the 10 percent of CDs in its minority and community bank program.

667. SCE's CDs have remained at a high, stable level with the 13-month rolling average increasing from \$195 million in 2012 to \$290 million at the end of 2018.

668. The interest SCE has paid on CDs has ranged from 0.19 percent-1.84 percent annually over the 2011-2018 period.

669. Although CD balances are forecasted to decline during this GRC cycle due to the Commission's recent decision in D.20-06-003, SCE still forecasts balances ranging from \$261.41 million in 2021 to \$221.89 million in 2023.

670. In recognition of the fact that CD balances will likely decline during this GRC cycle, it is reasonable to adopt the lowest average forecast value of \$221.89 million for the TY forecast.

671. It is reasonable for SCE to continue to use up to 10 percent of its CDs to promote its minority and community bank program.

672. Providing for recovery of CD-related interest costs makes the utility whole and makes SCE's CDs comparable to noninterest-bearing CDs for ratemaking purposes.

673. Consistent with past treatment, it is reasonable to authorize an offsetting interest expense for the portion of CDs that are applied as a reduction to rate base at the three-month non-financial commercial paper interest rate.

674. A Palo Verde Material and Supplies inventory forecast of \$31.863 million based on Palo Verde budget data with adjustments for sales tax and unpaid inventory is reasonable.

675. The removal of customer funding of Long-Term Incentives results in the removal of the corresponding rate base reduction in working cash.

Depreciation and Decommissioning

676. SCE proposes annual net salvage accruals that would result in a \$199 million increase over currently authorized rates based on current YE 2018 plant balances.

677. The currently authorized net salvage rates for the 11 accounts for which SCE requests higher net salvage accruals are insufficient to recover future costs of removal.

678. Some increase to net salvage for the 11 accounts identified by SCE during this GRC cycle is warranted.

679. Given the evidence presented by SCE regarding increasingly negative net salvage rates, keeping the rates frozen for another GRC cycle would result in a disproportionate share of removal costs for the identified 11 accounts being shifted to future ratepayers.

680. Given that the overall cost increases at issue in this GRC are substantial and ratepayers are facing a great deal of economic uncertainties associated with the global COVID-19 pandemic, and consistent with Commission precedent, it is reasonable to limit any net salvage increases to 25 percent of SCE's requested increases.

681. Both SCE and TURN rely on methodologies to determine ASLs that are not readily verifiable or able to be replicated.

682. There is no evidence of any major factors that would change the appropriateness of the ASL for Account 352 adopted in the last GRC, and therefore, it is reasonable to retain the previously authorized ASL of 55 years.

683. TURN's analysis of Account 352 based on past retirement activity in the account is not persuasive because it over-weights what is likely anomalous retirement activity.

684. There is no evidence of any major factors that would change the appropriateness of the ASL for Account 354 adopted in the last GRC, and therefore, it is reasonable to retain the previously authorized ASL of 65 years.

685. TURN's analysis of Account 354 based on past retirement activity is not persuasive given the minimal retirement activity recorded in this account.

686. There is no evidence of any major factors that would change the appropriateness of the ASL for Account 356 adopted in the last GRC, and therefore, it is reasonable to retain the previously authorized ASL of 61 years.

687. TURN's analysis of Account 356 based on past retirement activity is not persuasive given the minimal retirement activity recorded in this account.

688. Account 361 contains adequate retirement history with a relatively smooth and well-shaped curve.

689. Future forces of retirement for assets in Account 361 are not likely to significantly differ from those observed in the past.

690. It is appropriate to use past retirement activity to predict the ASL for Account 361.

691. Given the lack of clarity regarding SCE's methodology, SCE has failed to adequately justify its use of a 55-year ASL for Account 361.

692. TURN provides no justification as to why its proposed curve for Account 361, which would result in an ASL of 58 years, would be superior to the one with the best mathematical fit.

693. An ASL of 56 years for Account 361 is reasonable based on evidence that the 56-L0 curve falls within the range of the parties' proposals and has the closest mathematical fit to the OLT.

694. Account 362 contains adequate retirement history with a relatively smooth and well-shaped curve.

695. Future forces of retirement for assets in Account 362 are not likely to significantly differ from those observed in the past.

696. It is appropriate to use past retirement activity to predict the ASL for Account 362.

697. Given the lack of clarity regarding SCE's methodology, SCE has failed to adequately justify its use of a 65-year ASL for Account 362.

698. TURN's proposed ASL of 67 years for Account 362, which is based on a curve with a better mathematical fit to the OLT compared to SCE's proposal, is reasonable.

699. TURN's analysis of Account 366 is not persuasive given that it is based on minimal retirements recorded in the account and an OLT curve that does not appear well-suited to the curve fitting process.

700. Although SCE's statistical study was not determinative, SCE has adequately supported its proposal to retain the previously authorized service life of 59 years for Account 366.

701. Account 366 is comprised of conduit (44 percent), pull and slab boxes (23 percent), vaults (21 percent), and other various equipment.

702. SCE presents an uncontroverted engineering survey that indicates an expected or design life of 45-60 years for conduit, 20 years for pull and slab boxes, and 50 years for vaults.

703. Factors other than deterioration-related factors can reduce the expected life of assets in Account 366, such as mechanical damage from excavation, drilling crews inadvertently digging into conduit, or conductor failure.

704. The minimal retirement history in Account 369 is not ideal for conventional Iowa curve fitting techniques.

705. TURN's proposed curve for Account 369 is not the curve with the best mathematical or visual fit and is based largely on the judgment of TURN's expert, which is not adequately explained or justified.

706. There is no evidence of any major factors that would change the appropriateness of the ASL for Account 369 adopted in the last GRC, and therefore, it is reasonable to retain the previously authorized ASL of 55 years.

707. Retaining an ASL of 20 years for Account 370 is reasonable.

708. Account 370 does not have adequate retirement history for conventional Iowa curve fitting techniques.

709. Most of the assets in Account 370 consist of recently deployed AMI meters.

710. TURN's proposal of a 30-year ASL for Account 370 would place SCE above the industry average and the ASLs adopted for SDG&E and PG&E of 16 years and 20 years, respectively, for the same account.

711. SCE's uncontested proposals to extend the service lives for Accounts 367, 373, and 390 are reasonable.

712. SCE's uncontested proposals to retain the service lives for the remainder of the T&D accounts are reasonable.

713. It is reasonable for SCE to begin recovery for the Borel Powerhouse, Agnew Lake Dam, and Rush Meadows Dam given the high probability that decommissioning of these plants will take place within the next 10 years and the significant costs of decommissioning.

714. SCE estimates a 99 percent probability that it will initiate decommissioning of Borel within the next 5 years and a 90 percent probability that it will initiate decommissioning of Rush Meadows and Agnew Lake within the next 5-10 years.

715. SCE's undisputed probability-adjusted decommissioning cost estimates of \$85.2 million (\$2018) for Borel and \$41.7 million (\$2018) for Agnew Lake and Rush Meadows are reasonable.

716. SCE estimates a 50 percent probability of decommissioning for 3 plants (Gem Lake, Kaweah 3, and Tule) and a 10 percent probability of decommissioning for the remainder of its small hydro plants.

717. Given the degree of uncertainty regarding when SCE may initiate decommissioning of plants assigned a 50 percent or 10 percent probability of decommissioning, there is a lack of justification to begin recovery of decommissioning costs for these plants at this time.

718. Escalating decommissioning costs to the estimated end of service life would result in current ratepayers paying on a vastly overinflated expense.

719. For Mountainview, a dollar in the expected retirement year of 2040 is worth about 68 cents in 2021 dollars.

720. Escalating decommissioning estimates to the end of this rate cycle appropriately accounts for the time value of money and avoids the result of current ratepayers paying on a vastly overinflated expense.

721. SCE has not justified use of the Handy-Whitman escalation rate for decommissioning costs.

722. The Handy-Whitman index includes escalation for the cost of materials in addition to costs for labor and other ancillary construction equipment required for demolition.

723. TURN's recommendation of 4 percent escalation, which is based on data regarding national construction wages, is reasonable for escalation of decommissioning costs.

724. SCE has failed to provide justification for its \$6.5 million forecast for decommissioning of the Perris facility.

725. SCE recorded \$3.81 million in decommissioning costs for the Perris facility through June 24, 2020.

726. SCE was unable to identify what additional decommissioning or restoration work would be required for the Perris facility.

727. It is reasonable to authorize recovery of the recorded decommissioning costs of \$3.81 million for the Perris facility.

728. The Perris facility is no longer used and useful.

729. In the past, the Commission has found it appropriate to authorize a return on prematurely retired plant in instances where the retirement was due to Commission desires or actions.

730. The impetus for the decommissioning of the Perris facility was not due to Commission desires or actions.

731. In the past, the Commission has found it appropriate to authorize a return on prematurely retired plant in instances where the abandonment results in a net benefit to ratepayers.

732. There is no demonstration that the premature retirement of the Perris facility results in net benefits to ratepayers.

733. It is inconsistent with Commission precedent and an unfair division of risks and benefits for ratepayers to pay for the return on the Perris facility undepreciated plant balance of \$20.54 million and decommissioning costs of \$3.81 million for over a decade.

734. In both D.85-12-108 and D.92-12-057, the Commission removed the undepreciated balance of prematurely retired plants from rate base and amortized the recovery of the balance over five years with no return or interest earned.

735. It is reasonable to adopt TURN's proposal 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.

736. In the event that SCE recovers any proceeds from legal action related to the Perris facility, a reasonable division of the proceeds would be a 50/50 allocation between ratepayers and shareholders.

737. TURN's proposal to base the Palo Verde interim retirement net salvage rate on the 7-year (2012-2018) average is reasonable.

738. SCE does not provide sufficient evidence to support that the high level of Palo Verde interim retirements recorded in 2011 is likely to recur in the future.

739. TURN's proposal for recovery of 50 percent of SCE's requested fuel cells decommissioning costs during this GRC cycle is reasonable given the uncertainty

concerning whether decommissioning will be required at both of SCE's two fuel cell sites.

740. SCE has failed to justify use of a 25 percent contingency for removal of a small fuel cell installation.

741. TURN's recommendation of a 15 percent contingency for removal of a small fuel cell installation is reasonable.

Taxes

742. SCE's proposed methodologies for forecasting tax expense were unopposed with the exception of the California property tax forecast disputed by Cal Advocates.

743. SCE's uncontested methodologies for calculating tax expense set forth in Ex. SCE-07, Volume 2A, Chapter IV are reasonable.

744. It is reasonable to continue to use the five-year trend method for the California property tax forecast as proposed by Cal Advocates.

745. Cal Advocates withdrew its recommendation for a California property tax memorandum account and there is no apparent need to adopt one.

746. SCE's proposal to extend the 2018 TAMA in this rate case cycle is unopposed.

747. Continuation of the 2018 TAMA will aid the Commission's review of the reasonableness of SCE's election of various tax changes.

Other Results of Operations Issues

748. SCE uses a Commission-approved methodology to calculate factors to allocate total company costs between CPUC and FERC jurisdiction.

749. SCE's unopposed jurisdictional allocation factors presented in Ex. SCE-07, Vol. 1A2 at Table IV-8 are reasonable.

750. Unless otherwise specified in this decision, SCE's proposed escalation rates for labor, non-labor, and capital costs for 2014-2021 are reasonable.

751. SCE's uncontested A&G capitalization rate is reasonable.

752. SCE's uncontested P&B capitalization rate is reasonable.

Post-Test Year Ratemaking

753. It is reasonable to authorize a PTYR mechanism during this GRC cycle in order to give SCE an opportunity to offset some inflationary price increases and to recover costs for capital investments, particularly investments for wildfire risk mitigation, which are necessary for SCE to continue to provide safe and reliable service.

754. Since O&M expenses and capital costs affect the revenue requirement differently, it is reasonable to adopt a two-part PTYR mechanism that separately escalates O&M expenses and capital-related costs.

755. Given the large amount of wildfire capital additions that will be excluded in the test year due to AB 1054, it is reasonable for the PTYR mechanism to further bifurcate treatment of wildfire capital additions and non-wildfire capital additions.

756. It is reasonable for SCE to use its proposed utility-specific indices to escalate O&M expenses because they more accurately reflect how utilities incur costs.

757. The Consumer Price Index reflects consumer retail price changes and does not reflect how utilities incur costs.

758. It is reasonable to adopt a budget-based forecast for wildfire mitigation capital additions.

759. The AB 1054 exclusion results in \$399 million of SCE's wildfire capital additions being excluded from the TY forecast.

760. An attrition year revenue requirement for wildfire capital additions based on escalation of the TY forecast would not provide SCE with adequate funding in the post test-years for necessary investments in wildfire risk mitigation.

761. Although Cal Advocates did not review the 2022 and 2023 wildfire-related capital expenditure forecasts, these issues were vigorously litigated and there is a robust record on these issues due to TURN's analysis and alternative recommendations.

762. In recent GRCs, the Commission has rejected SCE's requests to use budget-based capital addition forecasts in its PTYR mechanism.

763. An attrition rate adjustment is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee a rate of return.

764. Budgets are not always implemented as planned.

765. SCE's proposed non-wildfire mitigation capital expenditures address 415 Work Breakdown Structure categories, which fall into approximately 120 activity areas.

766. With the exception of the Residential and Commercial New Service Connections forecasts, no party reviewed or analyzed SCE's non-wildfire capital budgets for 2022 and 2023.

767. The Residential and Commercial New Service Connections forecasts comprise the largest areas of non-wildfire capital spending proposed by SCE in this GRC.

768. Given that there are alternative budgets and a robust record concerning the Residential and Commercial New Service Connections forecasts for the Commission to consider, it is appropriate to adopt 2022 and 2023 budgets for these activities.

769. In order to help mitigate the impacts of large wildfire capital additions in the post-test years, and given the uncertainty in SCE's actual spending in these years and the economic uncertainty facing ratepayers due to the COVID-19 pandemic, it is reasonable to adopt zero escalation for SCE's non-wildfire related capital additions with the exception of the Residential and Commercial New Service Connections forecasts.

770. SCE's unopposed request to submit its annual attrition request via advice letter is reasonable.

771. SCE's unopposed request to continue the Z-Factor mechanism is reasonable.

Compliance Requirements

772. No party challenged or expressed any concerns with SCE's compliance requirements showing.

773. SCE has adequately demonstrated compliance with the items listed in its compliance exhibit.

Accessibility Issues

774. The joint proposal submitted by SCE and CforAT addressing accessibility issues for SCE's customers with disabilities builds off similar proposals adopted in prior GRCs and the proposed spending is in line with previously authorized amounts.

775. The uncontested joint proposal submitted by SCE and CforAT is reasonable.

SDG&E Request for SONGS-Related Cost Recovery

776. SDG&E owns a 20 percent interest in SONGS and is responsible for 20 percent of SONGS-related expenses.

777. In this GRC, SDG&E requests cost recovery for its 20 percent co-owner's share of Marine Mitigation projects and SONGS-related Workers' Compensation costs, which are ineligible to be paid from nuclear decommissioning trust funds.

778. SDG&E's unopposed request for cost recovery of its 20 percent share of SONGS-related costs is reasonable.

GRC Update Phase

779. Apart from SCE's updates to its forecast for vegetation management and its request for a PTYR mechanism, SCE's update testimony is uncontested.

780. The uncontested portions of SCE's update testimony are reasonable.

Settlements

781. The September 9, 2020, Joint Motion by SCE, SEIA, and Vote Solar for Approval of 2021 General Rate Case Settlement Agreement is uncontested.

782. The September 10, 2020, Joint Motion by SCE and the SoCal CCAs for Approval of 2021 General Rate Case Settlement Agreement is uncontested.

783. The September 9, 2020, Joint Motion by SCE and Conterra for Approval of 2021 General Rate Case Settlement Agreement is uncontested.

784. There is nothing in the record pertaining to the potential safety or cost implications that could result from Conterra being allowed to forego the submission of pole loading calculations.

785. The September 9, 2020, Settlement Agreement between SCE and Conterra does not specify who will pay for the one-time reduction to Conterra's outstanding invoices.

786. D.98-10-058 requires telecommunications carriers to reimburse a utility for reasonable pole attachment costs based on actual expenses incurred.

787. The September 9, 2020, Settlement Agreement between SCE and Conterra appears to contemplate complete forgiveness of outstanding SCE post-attachment inspection invoices.

788. SCE's and Conterra's testimony concerning pole attachment fees and SCE's OOR forecast have been admitted into the evidentiary record of this proceeding.

Conclusions of Law

1. As the applicant, SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application.

2. The standard of proof the applicant must meet in rate cases is that of a preponderance of the evidence.

3. Pursuant to Rule 12.1(d), the Commission will only approve settlements that are reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Proponents of a settlement agreement have the burden of proof of demonstrating that the proposed settlement meets the requirements of Rule 12.1 and should be adopted by the Commission.

5. All of the forecasts and ratemaking mechanisms we find to be reasonable in this decision should be approved.

Policy

6. Commission decisions in general rate case proceedings are guided by Pub. Util. Code §§ 451 and 454, which require SCE to "promote the safety, health, comfort, and convenience of its patrons, employees, and the public" while including only "just and reasonable" charges in its rates.

7. The increasing threat of catastrophic wildfires has made wildfire mitigation a high priority for the State and this Commission.

8. Cal Advocates' proposed \$125 million decrease to SCE's estimated 2020 capital expenditure budget to account for the economic downturn associated with the COVID-19 pandemic should be denied.

9. It is reasonable to consider each of SCE's individual requests for proposed programs and activities in the context of the ongoing COVID-19 pandemic, based on our assessment of the operating expenses and capital expenditures necessary for SCE to provide safe and reliable service at just and reasonable rates.

Affordability

10. A key element of finding a charge or rate just and reasonable is whether that charge or rate is affordable.

11. Affordability issues such as eligibility thresholds for CARE/FERA, disconnection policies, and consumer protections due to COVID-19 are outside the scope of this proceeding and are being actively examined in other proceedings.

12. The disconnection caps adopted in D.20-06-003 should be used as the metric for residential nonpayment disconnections required pursuant to Section 718(b).

13. In order to comply with the requirements of Section 718, SCE should include in its next GRC filing a report on the number and percentage of residential utility disconnections and amount of arrearages during this GRC cycle, and an analysis of the impacts that any proposed rate increases would have on disconnections and arrearages.

Risk-Informed Strategy and Business Plan

14. SCE's use of risk modeling to inform its GRC requests has enabled greater transparency and participation in this proceeding, increasing accountability for how safety risks are managed, mitigated, and minimized.

15. Cal Advocates' and TURN's recommendations to quantify the key constraints with selection of mitigation programs, address affordability in subsequent RAMP and GRC analysis, and use a specific timeframe for the probability of ignition calculation, should be deferred to R.20-07-013.

16. SCE should provide a qualitative explanation of any divergences between its "top-down" and "bottoms-up" risk modeling results, including how the results support SCE's proposed mitigations programs, in future RAMP and GRC filings.

17. Unless the issue of conditional risks is address in R.20-07-013, SCE should incorporate egress, and other conditional risks as appropriate, in future RAMP and GRC risk modeling.

18. SCE should clearly and transparently explain its rationale for selecting the type and scale of risk mitigations in future GRC requests, including how RSE calculations were considered.

Distribution Grid

19. SCE should be authorized to establish a two-way balancing account for the Underground Structure Replacement program for necessary underground structure replacement and shoring work described in this decision that cannot be deferred and must be replaced within this GRC cycle.

20. In D.18-05-042, the Commission amended Rule 18 to require utilities to correct Priority 3 maintenance items within 60 months, with specified exceptions.

21. Prior to D.18-05-042, there had been no deadline for utilities to correct Priority 3 maintenance items.

22. SCE should be authorized to continue use of the SRIIM adopted in the 2018 GRC with the modifications identified in this decision.

23. SCE's proposed modifications to the SRIIM headcount classifications, headcount target, and capital investment component should be adopted.

24. SCE's proposed modification to the SRIIM headcount measurement method should be denied.

Meter Activities

25. SCE's combined TY O&M forecast for Meter Activities should be approved.

26. SCE's 2019 recorded and 2020-2021 capital expenditure forecasts for Meter Engineering non-routine meter-related projects and Meter System Maintenance Design should be approved.

27. We should approve 2019 recorded and 2020-2021 capital expense forecasts of \$51.229 million for Meter Engineering routine meter work.

Transmission Grid

28. SCE is required to remediate 8,327 transmission line discrepancies by the NERC/WECC deadlines of 2025 for bulk electrical facilities and 2030 for radial facilities.

29. Cal Advocates' recommendation that the Commission authorize a memorandum account for SCE to track costs incurred above the forecast amount for the Aerial Inspection Maintenance program should be denied.

Grid Modernization, Grid Technology, and Energy Storage

30. SCE's TY O&M expense forecast for T&D Deployment should be approved.

31. SCE's TY O&M expense forecast for IT Project Support should be approved.

32. D.17-09-026 and D.18-02-004 adopted the use of 576 hourly profiles in the calculation of ICA results, which was the subject of ongoing dispute; provided

greater clarity and specificity regarding the disaggregation of load and DER forecasting at the circuit or circuit-segment level; and specified data redaction requirements.

33. D.19-05-020 does not limit future E&P Tool funding requests.

34. SCE's 2019 recorded and 2020-2021 forecast E&P Tools capital expenditures should be approved.

35. We should adopt \$110.553 million in capital expenditures for the GMS over the 2019-2021 period, which includes a \$5 million reduction from SCE's request to account for the two-year extension of labor costs.

36. SCE's 2019 recorded and 2020-2021 forecast Grid Modernization Automation capital expenditures should be approved.

37. Prior to SCE's next GRC request, SCE should hold one or more technical workshops to: (a) identify each circuit or circuit segment SCE intends to deploy RDA, along with the corresponding BCA (ranked by cost and associated CMI value); (b) further evaluate the costs and benefits, as well as the potential safety and asset degradation impacts, associated with an RCS/RFI-only approach; and (c) discuss any other alternatives that might achieve the same or similar functionalities at a lower cost. SCE should coordinate with Energy Division staff in developing the agenda for the technical workshop(s) to ensure that different stakeholder perspectives are incorporated.

38. SCE's 2019 recorded and 2020-2021 forecast Grid Modernization Communications capital expenditures should be approved.

39. SCE's 2019 recorded and 2020-2021 forecast Subtransmission Relay Upgrade Project capital expenditures should be approved.

40. SCE's 2019 recorded and 2020-2021 forecast Grid Technology capital expenditures should be approved.

41. SCE's TY O&M forecast for Grid Technology should be approved.
42. SCE's TY O&M forecast for the DESI Pilots should be approved.
43. SCE's 2019 recorded and 2020-2021 forecast DESI Pilots capital expenditures should be approved.

Load Growth, Transmission Projects, and Engineering

44. SCE should be authorized to establish a memorandum account to track and record capital expenditures associated with the early stages of SCE's DER-Driven Grid Reinforcement Program.

45. Given the high degree of uncertainty in the timing and magnitude of DER-driven reliability violations, it is not necessary to establish an associated capital expenditure "target" up to SCE's currently requested 2021-2023 forecast.

46. It is not within the scope of this proceeding to consider modification of prior Commission policy directives.

47. Load forecasting and planning for system reliability should be based on the best information available at the time of analysis.

48. SBUA's load forecasting recommendations are in direct conflict with D.18-02-004, the Commission's decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), as well as the Administrative Law Judge's August 1, 2018 ruling in R.14-08-013.

49. SBUA's comparison of load forecasts spanning 15 years ignores the differences in available information over time and the progression of load forecasting methodologies, including the more recent requirement that SCE use an IEPR demand forecast in developing its GRC Load Growth request.

50. Directing SCE to refile its entire GRC application would be an inefficient use of extensive party, Commission, and ultimately ratepayer resources.

51. SBUA's "percent of utilization" recommendation could result in significant public safety hazards.

52. SBUA's load growth recommendations should be denied.

53. SCE's 2019 recorded and 2020-2021 capital expenditure forecast for the Load Growth BPE should be approved.

54. SCE's 2019 recorded and 2020-2021 forecast Transmission Projects capital expenditures should be approved.

55. SCE's TY O&M forecast for the Engineering BPE should be approved.

New Service Connections and Customer Requested Modifications

56. The Streetlights System New Connections forecast should be updated based on the adopted residential gross meter sets forecast.

57. SCE's unopposed request to continue the one-way Rule 20A Balancing Account should be adopted.

Poles

58. In D.17-12-024, the Commission changed the timeframe for utilities to take corrective actions on potential safety hazards and potential violations of GO 95 in high fire-threat areas and, with limited exceptions, required that the updated requirements be fully implemented in Tier 3 by September 1, 2018 and in Tier 2 by June 30, 2019.

59. D.17-12-024 requires SCE to remediate overhead utility facilities, including poles, that create a fire risk located in Tier 3 within six months and Tier 2 within twelve months.

60. Prior to D.17-12-024, the required timeframes for remediating overhead utility facilities were between 12 and 59 months for Tier 3 pole replacements and 59 months for Tier 2 pole replacements.

61. SCE's unopposed request to continue the two-way PLDPBA, which includes capital-related revenue requirements for the Pole Loading Program and Deteriorated Pole Program and operating expenses for the Pole Loading Program, should be approved.

62. As in the 2015 and 2018 GRCs, the level of expenditures to be recovered in the PLDPBA over the 2021 GRC period should be capped at 15 percent above authorized levels.

Vegetation Management

63. SCE's TY O&M forecasts of \$107.012 million for Distribution Routine Vegetation Maintenance and \$12.760 million for Transmission Routine Vegetation Maintenance should be approved.

64. SCE's TY O&M forecast of \$35.120 million for Dead, Dying, or Diseased Tree Removal should be approved.

65. The record of this proceeding does not support SCE's proposed scope of the HTMP.

66. We should approve a TY O&M budget of \$24.085 million for the HTMP, which assumes the assessment of 75,000 trees per year and a tree failure rate of 11 percent.

67. The Commission's Energy Utility Rate Case Plan limits the scope of update testimony to known changes in cost of labor, changes in non-labor escalation factors, and known changes due to governmental action.

68. SCE's Vegetation Management Update Testimony exceeds the limited scope for update testimony and should be rejected.

69. Pursuant to Pub. Util. Code § 8386.4(b), SCE is authorized to record vegetation management costs in a memorandum account that are not otherwise included in SCE's authorized revenue requirement.

70. We should authorize a two-way VMBA to track the difference between the authorized O&M expenses for all vegetation management activities in this proceeding and SCE's recorded expenses for these activities, along with a requirement that recovery of costs in excess of 115 percent of the authorized amount for VMP activities be made by application. We should authorize SCE to seek recovery of costs between 100 percent and 115 percent of the authorized amount by a Tier 2 advice letter.

Wildfire Management

71. The deployment of 3,750 circuit miles of covered conductor reflects an efficient use of ratepayer dollars that will address SCE's highest risk circuit segments.

72. The actual performance and estimated unit cost of covered conductor should be further informed through the process of larger-scale deployment.

73. In its next GRC application, SCE should evaluate the interaction between its proposed wildfire mitigations and whether costs can be reduced for ratepayers while still maintaining a consistent level of safety.

74. In order to avoid reducing the risk reduction potential of the covered conductor circuit miles approved in this decision, it is reasonable to approve a 20 percent adder to account for operational design considerations, resulting in the total deployment of 4,500 circuit miles of covered conductor between 2019-2023.

75. Given the lack of adequate support in SCE's and TURN's proposals, we should adopt the lower cost 75/25 split between fire-resistant pole wraps to composite poles.

76. SCE should be authorized to create a two-way balancing account to track costs related to the actual replacement of poles under the WCCP.

77. SCE's 2019 recorded and 2020-2023 capital expenditure forecast to remediate approximately 3,200 tree attachments in SCE's HFRA should be approved.

78. We should approve a total of \$2.443 billion in 2019-2023 capital expenditures for SCE's WCCP.

79. SCE's TY O&M forecast for fusing mitigation should be approved.

80. SCE's 2019 recorded and 2020-2023 capital expenditure forecasts for fusing mitigation should be approved.

81. SCE should continue to receive rate of return treatment for assets retired under the WCCP.

82. SCE's TY O&M forecast for HFRA Sectionalizing Devices should be approved.

83. SCE's 2019 recorded and 2020-2023 forecast HFRA Sectionalizing Devices capital expenditures should be approved.

84. Additional funding for DFA deployment should not be provided until the results of the DFA pilot have been evaluated.

85. SCE's 2019 recorded and 2020-2023 forecast Targeted Undergrounding capital expenditures should be approved.

86. SCE's TY O&M forecasts for the PMO and OCM programs should be approved.

87. The record of this proceeding does not support SCE's proposal to replace all vertical switches in SCE's HFRA.

88. With the exception of SCE's forecast for wholesale replacement of vertical switches, SCE's 2019 recorded and 2020-2023 capital expenditure forecast for EOI should be approved.

89. SCE's TY O&M forecast for EOI is reasonable and should be approved.

90. SCE's TY O&M forecast for the Infrared and Corona Inspection Program should be approved.

91. SCE's TY O&M and 2019-2023 capital expenditure forecasts for PSPS Execution should be approved.

92. In D.20-05-051, the Commission stressed the importance of reducing the impact of, and need for, de-energization events to mitigate wildfire risk.

93. In Res. WSD-004, the Commission alerted SCE of the need to make quantitative commitments of expected reductions in PSPS frequency, scope, or duration.

94. SCE should, as part of its next GRC application, address how it leveraged the implementation of the grid hardening and modeling tools approved in this decision to better assess thresholds for initiating a PSPS event, including a quantitative evaluation of how covered conductor has resulted in higher thresholds for initiating a PSPS event, broken down by Tier 2 and Tier 3 HFTDs, as well as an evaluation of how covered conductor has contributed to reductions in SCE's historic PSPS frequency, scope, or duration.

95. SCE's TY O&M forecast for PSPS Customer Support should be approved.

96. The Commission supports the use and accelerated deployment of microgrids and resiliency projects to minimize the impacts of wildfire power outages and PSPS events.

97. We should not provide funding for SCE's CREIP proposal until SCE has adequately addressed the deficiencies identified in this decision.

98. SCE's TY O&M and 2019-2023 capital expenditure forecasts (including 2019 recorded) for Enhanced Situational Awareness are reasonable and should be approved.

99. SCE's TY O&M and capital expenditure forecasts for the Fire Science and Advanced Modeling Program are reasonable and should be approved.

100. Pub. Util. Code § 8386.4 does not prohibit the establishment of a balancing account for wildfire mitigation activities.

101. Pub. Util. Code § 8386.4 allows SCE to record any incremental fire-risk mitigation costs that are "not otherwise covered in the electrical corporation's revenue requirements."

102. SCE should be authorized to establish a two-way balancing account for the WCCP, along with the requirement that SCE file an application for reasonableness review of any recorded capital expenditures in excess of 110 percent of the amounts authorized in this decision. SCE should be authorized to seek recovery of capital expenditures between 100 percent and 110 percent of the authorized amount by a Tier 2 advice letter.

T&D Other Costs and Other Operating Revenue

103. SCE's T&D capital-expense ratios should be applied to the T&D capital expenditure forecasts adopted in this decision.

104. SCE's T&D OOR forecasts for ownership charges, transmission and distribution services, generation radial tie-lines, tie-line facilities rental agreements, miscellaneous revenue, Customer-Financed Added/Interconnection Facilities, and NEM should be approved.

105. SCE's proposed P&E and post-attachment inspection fees reflect SCE's actual cost of service and should be approved.

106. In light of the 68 percent failure rate SCE observed when conducting inspections of third-party attachments, it is in the public interest for SCE to conduct independent engineering work to validate compliance with SCE standards and GO 95 requirements.

107. SCE can and should be more diligent in making incremental updates to its P&E fee.

108. In recognition that SCE could have implemented a more gradual pole rental fee increase, it is reasonable for SCE to forgive, on a one-time basis, any late fees for outstanding invoices associated with pole attachment requests that were submitted on April 1, 2019 until the date of this decision.

109. As part of SCE's next GRC filing, SCE should evaluate whether waiving the requirement to submit pole loading calculations, or other similar process improvements, could be applied to third-party requests for pole attachments. For any proposed process improvement(s), SCE should consider whether there would be associated safety implications or additional costs borne by ratepayers.

110. SCE's TY T&D OOR forecast for Pole Rentals should be approved.

111. The FCC requires that a utility charge "just, reasonable, and nondiscriminatory rates for pole attachments."

112. SCE should include testimony with its next GRC application explaining how its pole attachment fees comply with the requirement that SCE charge just, reasonable, and nondiscriminatory rate for pole attachments when ECS is not subject to these fees but competes directly with other telecommunications providers.

Customer Interactions

113. SCE has failed to present convincing evidence or persuasive argument as to why the Commission's previous determination on Policy Adjustments should be revised.

114. SCE's TY O&M forecast for Billing Services should be based on 2018 recorded costs with no additional adjustments.

115. SCE's TY O&M forecast for Postage Expense forecast should incorporate the removal of the projected savings from the AIM Initiative and be adopted.

116. SCE has not met its burden of proof to support an increase in AHT or actual volume of work for Credit and Payment Services.

117. SCE's proposed TY labor increase of \$0.637 million for Credit and Payment Services should be denied.

118. We should remove SCE's proposed labor adjustment and adopt a TY O&M forecast of \$13.179 million for Credit and Payment Services.

119. SCE's Uncollectible Expenses factor should be approved.

120. Providing education after customers are defaulted to CPP is important to help customers to manage their energy use and bill impacts and in deciding whether to stay enrolled in CPP.

121. SCE's proposed funding for CPP education should be approved.

122. SCE has failed to present convincing evidence that all its existing authorized mass media campaigns are still needed, and that existing media funds could not be used to educate customers about Building Electrification.

123. We should authorize \$4.412 million in TY O&M for Customer CE&O, which incorporates adjustments for the removal of the AIM Initiative and a reduction for additional awareness and education related to Building Electrification.

124. It is critical that SCE track and evaluate the effectiveness of its outreach efforts to minority communities.

125. SCE should include testimony with its next GRC filing describing how current ACS data compares with more up-to-date information from the U.S. Census Bureau, whether SCE used the more up-to-date information, and why or why not.

126. SCE should meet with NDC to further develop the list of CBOs it currently utilizes for Customer CE&O, and should include a summary of the meeting(s), as well as a description of the specific communities SCE intends to target with in-language outreach, as part of its next GRC application.

127. SCE should include in its next GRC application specific cost estimates that would be needed for SCE's online and in-person Energy Center enrollment systems to be able to track demographic information.

128. SCE should provide some measure of the expenditures incurred for seminars and workshops to better evaluate future Energy Center facility upgrades and additions.

129. As part of its next GRC filing, SCE should provide an estimate of the annual expenditures for operating the Energy Centers, broken down, at a minimum, by in-person and online offerings, and divided by the total number of events (seminars, workshops, classes, etc.) offered that year.

130. SCE's TY O&M forecast for Escalated Complaints and Outreach should be approved.

131. To the extent SCE's Sprout Social system can accommodate the tracking of customer inquiries and complaints by language with minimal or no modifications, SCE should begin tracking this information immediately; otherwise, SCE should report the costs to modify its Sprout Social system to be able to track language information as part of its next GRC filing.

132. SCE should not be required to collect additional information by specific media channel.

133. SCE's TY O&M forecast for External Communications should be approved.

134. SCE's TY O&M forecast for the CCC should be approved.

135. SCE's existing TE Advisory Services is sufficient to cover the activities and level of staff SCE anticipates needing for TE-related account manager activities over this GRC period.

136. We should authorize a total TY O&M forecast of \$14.509 million for Business Account Management activities.

137. SCE's TY O&M forecast for Digital Operations and Management should be approved.

138. SCE's requested increase for customer experience improvement should be approved.

139. It is important for SCE to have a clear and comprehensive process for establishing customer concerns.

140. SCE's TY O&M forecast for CEM should be approved.

141. SCE's request to fund Hydraulic Services should be approved.

142. SCE should be directed to report in its next GRC filing whether any of the third-party agricultural programs include pump services, and alter its GRC funding request accordingly.

143. SCE's TY O&M forecast for Business Account Management Services should be approved.

144. SCE should report how closely its current solar photovoltaic forecast compares with actual NEM solar applications received.

145. SCE's TY O&M forecast for Customer Programs Management should be approved.

146. SCE's TY O&M request for the new TE group should be rejected.

147. SCE's 2019-2021 capital expenditure forecast for Customer Care Services Tools and Equipment should be adopted.

148. The Commission has consistently found that applicants have the burden of affirmatively establishing the reasonableness of all aspects of their requests in direct testimony, and that, based on the principle of fairness, rebuttal testimony is not the place to present requests or foundational evidence for the first time.

149. SCE's 2019-2021 Customer Contact Center capital expenditure request should be rejected.

150. The incentive to meet the goals of the Service Guarantee Program is most effective when paid for by shareholders.

151. SCE has not presented a persuasive argument for ratepayer funding of service guarantees.

152. SCE's Customer Interactions OOR forecast should be approved with the removal of ratepayer funded Service Guarantee Standards.

Business Continuation

153. SCE's TY O&M forecast for Planning, Continuity, and Governance should be approved.

154. SCE's TY O&M forecast for All Hazards Assessment, Mitigation, and Analytics is reasonable and should be approved.

155. Budgeting for contingencies is not necessarily appropriate in the context of a general rate case, where the utility must demonstrate the reasonableness of every dollar in its forecast revenue requirement.

156. The contingencies in SCE's forecasts for Transmission Substation Mitigation (\$14.4 million) and for Non-Electric Facilities (\$1.366 million) should be removed.

157. SCE should track how closely actual recorded project costs align with its 2019-2023 cost estimate for the MEER projects and include this information with its next GRC filing.

158. SCE has not established that the large \$11 million office building is representative of the retrofit projects that SCE plans to complete during 2019-2023.

159. We should remove the \$11 million office building from SCE's Non-Electric Facilities forecast, which would revise the cost per sq. ft. to \$28.66.

160. SCE should be allowed to create a memorandum account to track seismic retrofit costs for its Non-Electric Facilities, with the opportunity to seek recovery for any costs above the amount authorized in this decision in SCE's next GRC.

161. With the removal of contingency factors (Electric Infrastructure and Non-Electric Facilities forecasts), and the removal of the large \$11 million office building (Non-Electric Facilities forecast), the remainder of SCE's 2019-2021 capital expenditure forecast for the Seismic Assessment and Mitigation Program should be approved.

162. SCE's 2019 recorded and 2020-2021 forecast Climate Adaptation and Severe Weather Program capital expenditures should be approved.

Emergency Management

163. SCE's TY O&M forecasts for Emergency Management should be approved.

164. We should adopt a 2019-2021 capital expenditure amount of \$164.152 million for Emergency Management, which reflects SCE's initial 2019-2021 capital expenditure forecast and is consistent with SCE's purported forecast methodology.

Generation

165. SCE cannot begin physical decommissioning of San Geronio until the FERC license and transfer process is complete.

166. SCE must install 2 new clean diesel generators on Catalina Island by January 1, 2023 to meet the compliance deadline for a Nitrogen Oxide (NO_x) emissions reduction target set forth in SCAQMD Rule 1135.

167. SCE should submit a standalone application with its most up to date version of the Catalina Repower project proposal for additional review.

168. SCE should be authorized to create a Catalina Repower Memorandum Account to track costs related to the Catalina Repower project for possible future recovery following a reasonableness review in the next GRC.

169. Palo Verde excess water sales are not a new category or activity requiring approval under Affiliate Transaction Rule VII(D).

170. Palo Verde excess water sales fall under SCE's existing NTP&S offering "sale or trading of excess water rights" under the Secondary Use of Utility-Owned Generation Facilities and Land category, previously approved by the Commission in Resolution E-3639.

171. The Commission has designated excess water sales such as the Palo Verde excess water sales as "passive," which pursuant to the Gross Revenue Sharing Mechanism adopted in D.99-09-070, results in customers being allocated 30 percent of gross revenues.

172. SCE's correction of its accounting error and classification of Palo Verde excess water sales as passive NTP&S is treatment the Commission has previously authorized in D.99-09-070 and Resolution E-3639 and does not require further Commission authorization.

Insurance

173. The Commission routinely authorizes ratepayer recovery of wildfire liability insurance costs through GRCs without requiring cost sharing between

ratepayers and shareholders as long as the utility has demonstrated that its forecast costs are reasonable.

174. The Commission regularly authorizes ratepayer recovery of incremental wildfire liability insurance costs without shareholder cost sharing unless there are findings of utility imprudence.

175. The proposals by TURN and Cal Advocates to allocate the costs of wildfire liability insurance premiums to both ratepayers and shareholders would depart from well-established Commission precedent.

176. Consistent with Commission precedent, SCE should be authorized to recover the wildfire liability insurance cost forecast we adopt in this decision in rates without allocation of any of these costs to shareholders.

177. SCE should not be precluded from relying on alternative risk transfer instruments in place of traditional wildfire liability insurance when circumstances warrant.

178. SCE should report on any use of alternative risk transfer instruments during this rate case period, including the circumstances that warranted such use, in its next GRC for the Commission's review.

179. A higher level of scrutiny is warranted for any rate recovery above the adopted wildfire liability insurance forecast, including SCE's use of any alternative risk transfer instruments.

180. SCE's proposed two-way Risk Management Balancing Account to capture the difference between SCE's actual and authorized wildfire liability insurance expense should be denied.

181. Given the volatility and uncertainty of wildfire liability insurance costs, SCE should establish a one-way balancing account to ensure that any overcollection is returned to ratepayers and SCE should be authorized to

continue to seek rate recovery of any costs in excess of the forecast through the WEMA.

182. SCE does not identify a legal requirement that wildfire-related insurance premiums previously authorized in the 2015 and 2018 GRCs now be expensed.

183. The FERC Order cited by SCE (*San Diego Gas & Elec. Co.* (2012) 140 FERC 61,108) does not require the expensing of the previously authorized insurance premiums.

Employee Benefits and Programs

184. SCE's unopposed requests to continue two-way balancing account treatment for Pension costs, PBOP costs (excluding actuarial fees), Medical Programs, Dental Plans, and the Vision Plan should be approved.

185. The executive compensation forecast we authorize is required to be consistent with SB 901, which revised Section 706.

186. SB 901 requires that compensation paid to an officer of an electrical corporation be paid solely by shareholders of the electrical corporation.

187. SB 901 does not define who is an "officer" of an electrical or gas corporation or set forth any statement of the Legislature's intent with respect to amended Section 706.

188. The definition of "officer" adopted in Resolution E-4963 does not preclude future consideration of the definition.

189. SCE has been afforded due process in this proceeding with respect to a possible change to the definition of "officer" for purposes of determining its recoverable executive compensation costs for this GRC period, and any definition we adopt in today's decision would apply only to SCE, not to any other IOU.

190. Rule 3b-7 defines an “executive officer,” whereas Section 706 uses the term “officer.”

191. The terms “executive officer” and “officer” are used interchangeably in Commission proceedings and decisions, and by the SEC.

192. All compensation, as defined by Section 706, for SCE executives who are Rule 3b-7 officers of SCE should be excluded from rates.

193. All compensation, as defined by Section 706, for shared officers who are Rule 3b-7 officers of SCE should be excluded from rates.

194. Section 706 only applies to officers of an electrical or gas corporation.

195. Section 706 does not apply to officers of EIX.

196. TURN’s recommendation that compensation for EIX executives that is allocated to SCE be excluded from rates should be denied.

197. SCE should submit a Tier 1 advice letter updating its Officer Compensation Memorandum Account consistent with the directives of this decision.

198. SCE should exclude all costs for SCE executives and shared officers who are Rule 3b-7 officers of SCE from the Executive Benefits forecast and, consistent with Commission precedent, exclude 50 percent of the remainder of the Executive Benefits forecast from rates.

199. SCE’s request to include Long-Term Incentive costs in rates should be denied.

200. Cost-of-service ratemaking principles do not require ratepayers to fully fund incentive compensation where elements of the program essentially benefit shareholders without a clear demonstrable benefit to ratepayers.

201. Ratepayer funding for STIP should be based on the following methodology: (1) application of a 16.10 percent ratio to SCE’s adopted labor

forecast; and (2) reduction of the resulting forecast by 50 percent to remove costs associated with financial and policy shaping goals.

202. SCE's recognition program budget based on each Operating Unit having a budget of 0.15 percent of its individual labor budget should be approved.

Environmental Services

203. SCE's requested funding for its new proposed Avian Retrofits program should be denied.

Audit Services

204. Expenses for the Third Party Review audit totaling \$150,863 should be excluded when determining the TY forecast for Audit Services.

Enterprise Operations

205. SCE's TY O&M forecast for Enterprise Operations should be adopted.

206. SCE's 2019 recorded and 2020-2021 forecast Transportation Services capital expenditures should be approved.

207. SCE's 2019 recorded and 2020-2021 capital expenditure forecasts for the T&D Training Center and Devers and Rector Maintenance and Test Buildings are reasonable and should be approved.

208. We should deny SCE's request to fund the Santa Barbara Service Center and Vehicle Maintenance Facilities projects.

209. With the exclusion of the Santa Barbara Service Center and Vehicle Maintenance Facilities projects, we should approve a 2019-2021 capital expenditure forecast of \$351.038 million for Facility and Land Operations.

210. SCE's 2019 recorded and 2020-2021 capital expenditure forecast for Transportation Services should be approved.

Policy and External Engagement

211. It has generally been the Commission's policy to deny ratepayer funding of EEI dues unless a utility provides sufficient evidence to establish clear ratepayer benefits.

212. The EEI invoice is insufficient evidence to establish the portion of the invoice which should be recovered from ratepayers.

GRC-Related Balancing and Memorandum Accounts

213. SCE's unopposed request to transfer the December 31, 2020 balance in the ECPMA to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels should be granted.

214. SCE unopposed request to transfer the ending December 31, 2020 IDERACMA and DDACMA balances, including accrued interest, to the distribution sub-account of the BRRBA to be recovered from all customers through distribution rate levels should be granted.

215. SCE's uncontested proposal to eliminate the ACESBA should be granted.

216. SCE's unopposed request to continue the RRIMA until the end of the 2021 GRC cycle should be granted.

217. SCE's uncontested proposal to remove recovery of cooling center costs from Preliminary Statement Part AA, CARE should be granted.

218. SCE's uncontested request to establish the ZFMA to track costs associated with Z-Factor events should be granted.

219. SCE unopposed request to continue the two-way PBOPBA through the 2021 GRC cycle to record the difference between authorized and actual PBOP expenses should be granted.

220. SCE unopposed request to continue the two-way PCBA through the 2021 GRC cycle to record the difference between authorized and actual pension expenses should be granted.

221. SCE's unopposed request to continue the two-way MPBA through the 2021 GRC cycle to record the difference between authorized and actual medical, dental, and vision expenses should be granted.

222. SCE unopposed request to continue the one-way STIPMA through the 2021 GRC cycle to record the difference between authorized and actual STIP expenses should be granted.

Other Ratemaking Proposals

223. The Commission evaluates each renewed funding request to determine whether there is adequate justification for the deferral and for the additional funding request.

224. As with all other aspects of its application, SCE, as the applicant, bears the burden to establish the reasonableness of its decision to defer projects and reprioritize funding, and of any renewed request for funding.

Other Operating Revenue (OOR)

225. SCE has made a *prima facie* showing regarding compliance of its NTP&S offerings with the Commission's Affiliate Transaction Rules.

226. SCE should include supporting testimony in its next GRC filing addressing the NTP&S-related issues/questions raised in this decision.

227. EPUC's proposals for changes to SCE's Added Facilities tariff are appropriate for consideration in this GRC.

228. Changes to SCE's methodology for calculating Added Facilities rates are not warranted.

229. SCE's uncontested proposals for addressing terminated or terminating Added Facilities contracts with 20-year terms should be approved.

Rate Base

230. The question of whether the Commission should allow recovery in rates for pole replacements through the aged pole program turns on the prudence of the investment decision.

231. There is a lack of Commission precedent that supports using a present value revenue requirement showing or customer indifference standard to determine the duration of a disallowance.

232. Recovery for the 2014 and 2015 pole replacements through the aged pole program should continue to be disallowed through this GRC cycle.

233. SCE should present the impacts of any write-off and tax benefit unwinding proposal related to the aged pole program to the Commission for review when seeking Commission review and approval of the recorded operation of the Tax Accounting Memorandum Account.

234. SCE's proposed 0-day lag for depreciation expense is consistent with Standard Practice U-16 and Commission precedent.

235. Adoption of TURN's proposal to use 365 lag days for both state and federal taxes is not incompatible with OII 24.

236. OII 24 does not foreclose the possibility that under extraordinary circumstances, it would be appropriate for the Commission to consider tax impacts associated with events outside the rate case in forecasting income tax expenses for ratesetting purposes.

237. Circumstances under which a utility has not paid federal taxes for over a decade and state taxes for over a GRC cycle constitute extraordinary

circumstances that would justify the Commission considering tax impacts associated with events outside the rate case.

238. SCE fails to present a convincing argument as to why the Commission should discontinue the longstanding policy of treating CDs as a source of permanent working capital for SCE.

239. CDs should continue to be used as a rate base offset for SCE.

240. SCE should be authorized an offsetting interest expense for the portion of CDs that are applied as a reduction to rate base at the three-month non-financial commercial paper interest rate.

Depreciation and Decommissioning

241. Application of a gradualism principle to SCE's net salvage rates is consistent with Commission precedent.

242. Application of a gradualism principle to net salvage rates is reasonable to balance customers' respective cost burden between current and subsequent GRC cycles.

243. It is reasonable to be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect.

244. Consistent with the treatment adopted in D.19-05-020, generation decommissioning estimates should be escalated through the end of this GRC cycle.

245. It is reasonable to require future ratepayers who will be paying in cheaper nominal dollars to pay more than current ratepayers paying in 2021-2024 dollars in order to account for the time value of money.

246. A 4 percent escalation rate should be applied to historical decommissioning escalation, except for SCE's small hydro assets, as well as for future decommissioning escalation through 2024.

247. SCE should conduct fresh decommissioning studies for Mountainview, a representative peaker, and a representative solar plant for its next GRC given that it has been 10-18 years since the most recent studies.

248. It is a longstanding regulatory principle that shareholders should earn a return only on used and useful plant.

249. It is inappropriate for SCE to continue to receive a return on the Perris investment because it has been decommissioned and is no longer used and useful.

250. The fact that Perris was previously afforded group accounting treatment is not controlling.

251. Prior group accounting treatment of plant is alone insufficient to justify an exception to the general policy that utilities should only earn a return on plant that is used and useful, particularly in cases involving a large standalone project or large amounts of plant.

252. It is appropriate for the Commission to critically review the use of group accounting and its alternatives in instances where it appears that the undepreciated balances of premature plant retirements would not be offset to a large degree by plant assets that exceed their expected lives.

253. With respect to the Perris facility, SCE fails to justify an exception from the general policy that only used and useful plant should earn a return.

254. TURN's proposal 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 should be adopted.

Taxes

255. SCE's unopposed proposal to extend the 2018 Tax Accounting Memorandum Account in this rate case cycle should be adopted.

Post-Test Year Ratemaking

256. Utilities are not automatically entitled to an attrition mechanism between rate cases.

257. The Commission has the discretion to grant or deny requests for an attrition mechanism between rate cases.

258. SCE's unopposed request to submit its annual attrition request via advice letter should be approved.

259. SCE's unopposed request to continue the Z-Factor mechanism should be approved.

SDG&E Request for SONGS-Related Cost Recovery

260. SDG&E should update its SONGS revenue requirement for 2022 and 2023 based on SCE's approved Marine Mitigation and SONGS-related Workers' Compensation costs and SDG&E's authorized FF&U rate.

GRC Update Phase

261. The uncontested portions of SCE's update testimony should be approved and reflected in the final approval amounts throughout this decision.

Settlements

262. The September 9, 2020, Joint Motion by SCE, SEIA, and Vote Solar for Approval of 2021 General Rate Case Settlement Agreement is reasonable in light of the record, consistent with the law, and in the public interest.

263. The September 10, 2020, Joint Motion by SCE and the SoCal CCAs for Approval of 2021 General Rate Case Settlement Agreement is reasonable in light of the record, consistent with the law, and in the public interest.

264. The September 9, 2020, Joint Motion by SCE and Conterra for Approval of 2021 General Rate Case Settlement Agreement does not meet the requirements of Rule 12.1(d) and should be rejected.

265. There is sufficient record evidence to resolve all disputed issues between SCE and Conterra and make a final determination on the OOR forecast for pole attachments.

Motions

266. All of the oral and written rulings issued by the assigned ALJs in this proceeding are affirmed.

267. The Motion of the Public Advocates Office for Leave to File Under Seal Confidential Portion of Opening Brief filed on September 11, 2020 should be granted.

268. The Motion of Southern California Edison for Admission of Late-Filed Errata into the Evidentiary Record filed on September 29, 2020 should be granted.

269. Any outstanding motions or requests that have not been addressed in this decision or elsewhere are deemed denied.

O R D E R

IT IS ORDERED that:

1. Application 19-08-013 is granted to the extent set forth in this Decision. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2021 test year base revenue requirement set forth in Appendix B, effective January 1, 2021.

2. Within 30 days from the effective date of this decision, Southern California Edison Company shall file a Tier 1 advice letter to implement the revenue

requirement and ratemaking adopted herein. The revenue requirement and revised tariff sheets will be effective January 1, 2021. The balance of the General Rate Case Revenue Requirement Memorandum Account shall be amortized in rates October 1, 2021, or as soon thereafter as may be effected, to December 31, 2023.

3. Southern California Edison Company (SCE) is authorized to implement a Post-Test Year Ratemaking (PTYR) mechanism for both 2022 and 2023 as set forth in this decision. SCE shall submit a Tier 2 advice letter by December 1, 2021 for the 2022 PTYR and December 1, 2022 for the 2023 PTYR. The advice letters shall specify the revenue requirement adjustment for Operations and Maintenance expense escalation and changes in capital-related costs.

4. Within 30 days of the issuance of this decision, Southern California Edison Company shall file a Tier 1 advice letter to establish a two-way balancing account for the Underground Structure Replacement program for necessary underground structure replacement and shoring work described in this decision that cannot be deferred and must be replaced within this General Rate Case cycle.

5. Southern California Edison Company is authorized to continue use of the Safety and Reliability Investment Incentive Mechanism with the modifications set forth in this decision.

6. Within 60 days of the issuance of this decision, Southern California Edison Company shall file a new application for review and approval of the Catalina Repower project.

7. Southern California Edison Company is authorized to create a Catalina Repower Memorandum Account to track costs related to the Catalina Repower

Project for possible future recovery following a reasonableness review in its next General Rate Case.

8. In its next General Rate Case, Southern California Edison Company shall report on its Supplier Diversity and Development department's small business programming and outreach efforts undertaken during this General Rate Case cycle.

9. Southern California Edison Company shall report on any use of alternative risk transfer instruments in place of traditional wildfire liability insurance during this rate case period, including the circumstances that warranted such use, in its next General Rate Case for the Commission's review.

10. Within 30 days of the issuance of this decision, Southern California Edison Company (SCE) shall file a Tier 1 advice letter to establish a one-way balancing account to capture the difference between SCE's actual and authorized wildfire liability insurance expense.

11. Southern California Edison Company (SCE) shall include in its next General Rate Case (GRC) filing a report on the number and percentage of residential utility disconnections and amount of arrearages during this GRC cycle, and an analysis of the impacts that any proposed rate increases would have on disconnections and arrearages. SCE's report shall: (1) reflect consideration of approaches other than the Consumer Price Index to capture changes in purchasing power, such as use of nominal bills and rates (*e.g.*, if there are minimal changes) or household income levels; and (2) present analyses based solely on bill variables. SCE is also not precluded from presenting any additional analyses of its choosing.

12. Southern California Edison Company is authorized to create a Memorandum Account to track costs related to the Distribution Energy Resources-Driven Grid Reinforcement Program.

13. Prior to its next General Rate Case filing, Southern California Edison Company (SCE) shall hold one or more technical workshops to: (a) identify each circuit or circuit segment where SCE intends to deploy Reliability-Driven Distribution Automation, along with the corresponding benefit-cost analysis (ranked by cost and associated Customer Minute of Operation value); (b) further evaluate the costs and benefits, as well as the potential safety and asset degradation impacts, associated with a Remote Control Switches/Remote Fault Indicators-only approach; and (c) discuss any other alternatives that might achieve the same or similar automation functionalities at a lower cost. SCE shall coordinate with Energy Division staff in developing the agenda for the technical workshop(s) to ensure different stakeholder perspectives are incorporated.

14. Within 30 days of the issuance of this decision, Southern California Edison Company (SCE) shall file a Tier 1 advice letter to create a two-way Vegetation Management Balancing Account to track the difference between the expenses for vegetation management authorized in this decision and SCE's recorded expenses for these activities. Recovery of any undercollection that is less than 115 percent of the authorized amount as well as the refund of any overcollection, shall be filed via a Tier 2 advice letter. Recovery of costs in excess of 115 percent of the authorized amount for Vegetation Management shall be made by application.

15. Within 30 days of the issuance of this decision, Southern California Edison Company (SCE) shall file a Tier 1 advice letter to create a two-way Wildfire Risk Mitigation Balancing Account to track the difference between the Wildfire Covered Conductor Program (WCCP) capital expenditures authorized in this

decision and SCE's recorded expenses for these activities. Recovery of any undercollection that is less than 110 percent of the authorized capital expenditure amount, as well as the refund of any overcollection, shall be filed via a Tier 2 advice letter. Recovery of capital expenditures in excess of 110 percent of the authorized amounts for the WCCP shall be made by application. Should SCE file an application for cost recovery, SCE may request an expedited schedule to review its request pursuant to Rule 2.9 of the Commission's Rules of Practice and Procedure.

16. Southern California Edison Company (SCE) shall include in its next General Rate Case filing a presentation of how it leveraged the implementation of the grid hardening and modeling tools approved in this decision to better assess thresholds for initiating a Public Safety Power Shutoff (PSPS) event, including a quantitative evaluation of how covered conductor has resulted in higher thresholds for initiating a PSPS event, broken down by Tier 2 and Tier 3 High Fire-Threat Districts, as well as an evaluation of how covered conductor has contributed to reductions in SCE's historic PSPS frequency, scope, or duration.

17. Southern California Edison Company (SCE) shall include in its next General Rate Case filing a description of how current American Community Survey data compares with more up-to-date information from the United States Census Bureau, whether SCE used the more up-to-date information, and why or why not.

18. Southern California Edison Company (SCE) shall include in its next General Rate Case filing a summary of the meeting(s) held with the National Diversity Coalition to further develop the list of community-based organizations SCE currently uses for Customer Communications, Education, and Outreach, as

well as a description of the specific communities SCE intends to target with in-language outreach.

19. Southern California Edison Company (SCE) shall include in its next General Rate Case filing cost estimates for the work that would be needed for SCE's online and in-person Energy Center enrollment systems to be able to track participant demographic information.

20. Southern California Edison Company shall include in its next General Rate Case filing an estimate of the annual expenditures for operating the Energy Centers, broken down, at a minimum, by in-person and online offerings, and divided by the total number of events (seminars, workshops, classes, etc.) offered that year.

21. If Southern California Edison Company's (SCE) existing Sprout Social system can accommodate the tracking of customer inquiries and complaints by language with minimal or no modifications, SCE shall begin tracking this information immediately; otherwise, SCE shall report the costs to modify its Sprout Social system to be able to track language information in its next General Rate Case filing.

22. Southern California Edison Company shall report in its next General Rate Case (GRC) filing whether any of the third-party agricultural programs include pump services, and shall alter its GRC funding request accordingly.

23. In its next General Rate Case filing, Southern California Edison Company (SCE) shall evaluate whether waiving the requirement to submit pole loading calculations, or other similar process improvements, could be applied to third-party requests for pole attachments. For any proposed process improvement(s), SCE should consider whether there would be associated safety implications or additional costs borne by ratepayers.

24. Southern California Edison Company shall include in its next General Rate Case filing an explanation of how its pole attachment fees comply with the requirement by the Federal Communications Commission that a utility charge “just, reasonable, and nondiscriminatory rates for pole attachments” when Edison Carrier Solutions competes directly with other telecommunications providers but is not subject to the same pole attachment fees.

25. Southern California Edison Company (SCE) shall track how closely actual recorded project costs align with SCE’s 2019-2023 seismic cost estimate for the Mechanical Electrical Equipment Rooms and include this information in its next General Rate Case filing.

26. Southern California Edison Company is authorized to create a memorandum account to track seismic retrofit costs for its Non-Electric Facilities and may seek reasonableness review for any costs above the amount authorized in this decision in its next General Rate Case filing.

27. Within 30 days of the issuance of this decision, Southern California Edison Company (SCE) shall submit a Tier 1 advice letter updating its Officer Compensation Memorandum Account consistent with the directives of this decision. In its Tier 1 advice letter implementing the test year revenue requirement, SCE shall identify and remove from rates all compensation, as defined by Public Utilities Code Section 706, for SCE executives and shared officers consistent with the directives of this decision.

28. Southern California Edison Company shall include supporting testimony in its next General Rate Case filing addressing the Non-Tariffed Products and Services-related issues and questions raised in this decision.

29. Southern California Edison Company shall conduct new decommissioning studies for Mountainview Generating Station, a representative peaker, and a representative solar plant for its next General Rate Case.

30. San Diego Gas and Electric Company (SDG&E) shall file an annual Tier 1 advice letter updating its San Onofre Nuclear Generation Station (SONGS)-related revenue requirement for 2022 and 2023 based on SDG&E's approved Marine Mitigation and SONGS-related Workers' Compensation Costs and SDG&E's authorized Franchise Fees and Uncollectibles rate.

31. The September 9, 2020 Joint Motion by Southern California Edison Company, the Solar Energy Industries Association, and Vote Solar for Approval of 2021 General Rate Case Settlement Agreement is granted.

32. The September 10, 2020 Joint Motion by Southern California Edison Company, California Choice Energy Authority, and the Clean Power Alliance of Southern California for Approval of 2021 General Rate Case Settlement Agreement is granted.

33. The September 9, 2020, Joint Motion by Southern California Edison Company and Conterra Ultra Broadband Holdings, Inc. for Approval of 2021 General Rate Case Settlement Agreement is denied.

34. The Motion of the Public Advocates Office for Leave to File Under Seal Confidential Portion of Opening Brief filed on September 11, 2020 is granted.

35. The Motion of Southern California Edison Company for Admission of Late-Filed Errata into the Evidentiary Record filed on September 29, 2020 is granted.

36. In its next General Rate Case (GRC), Southern California Edison Company (SCE) shall provide tables with at least five years of recorded spending information associated with each individual expense or expenditure forecast in

excess of \$1 million. SCE shall also provide summary tables, aggregating this information at the level of major categories (*e.g.*, Transmission and Distribution Infrastructure Replacement, Human Resources). SCE shall provide its own comparable forecast and the Commission's adopted forecast from this GRC as a component of or accompaniment to these tables, both for individual forecasts and summary tables. SCE shall briefly explain any changes in scope of the forecasts, if they are not directly comparable. In the summary tables, SCE shall include any expenses or expenditures that were included in this GRC request, even if the individual expense or expenditure was not actually approved in this decision or implemented by SCE.

37. Application 19-08-013 remains open.

This order is effective today.

Dated August 19, 2021, at San Francisco, California.

MARYBEL BATJER

President

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

GENEVIEVE SHIROMA

DARCIE HOUCK

Commissioners