BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Southern California Edison Company for Authority to Increase its Authorized Revenues for Electric Service in 2018, Among Other Things, and to Reflect that Increase in Rates.	Application 16-09-001 (Filed September 1, 2016)

OPENING BRIEF OF THE OFFICE OF RATEPAYERS ADVOCATES

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In accordance with Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), and the schedule set by Administrative Law Judges (ALJs) Roscow and Wildegrube, the Office of Ratepayer Advocates (ORA) submits this Opening Brief for the General Rate Case (GRC) Application of Southern California Edison Company (SCE or Edison) for Test Year (TY) 2018.

SCE filed its GRC Application, A.16-09-001, on September 1, 2016. In its Application, SCE sought revenue requirement increases for the three-year period from 2018 through 2020 amounting to a cumulative total of approximately $2.3 billion over SCE's currently authorized rate level. Through numerous Errata and Rebuttal, SCE eventually reduced its requested revenue requirement increase to $196 million for TY 2018.[1] Thus, as of the close of evidentiary hearings, SCE was requesting a cumulative total of $ 2.1 billion for 2018-2020.[2] If SCE's request were approved, SCE's TY 2018 revenue requirement would be $5.859 billion.[3]

This Brief addresses the proposals of SCE that ORA disputes. Silence on any argument should not be interpreted as assent.

1. POLICY

In its direct testimony, SCE says that its GRC request, "placed in context" contemplates "… significant investment in the electric infrastructure to replace our aging equipment, add

[1] Ex. SCE-25, Vol. 1, p. 4.

[2] Ex. SCE-25, Vol. 1, p. 4, Table I-3; $196 million for each year 2018-2020, $480 million for 2019-2020 and $556 million for 2020 totals $2.1 billion.

[3] Ex. SCE-25, Vol, p. 1, Table I-1.

capacity to address customer and load growth, improve safety and reliability and enhance capabilities to integrate [Distributed Energy Resources]."[4] To truly place SCE's request in context, however, the Commission should bear in mind all the other proceedings in which SCE is asking for millions of dollars from its customers.

These includes, but are not limited to the following: SCE's Energy Efficiency Business Plan,[5] the Demand Response application,[6] the Electric Program Investment Charge proceeding, and the Integrated Distributed Energy Resource proceeding. While SCE says that it has taken steps to make sure there is no double counting, as discussed below in connection with SCE's Energy Storage Pilot proposal, it certainly appears that SCE is seeking funding in this GRC to duplicate efforts that the Commission has already authorized the utilities to fund and execute in other proceedings.

In this GRC, SCE is seeking $3.8 billion for 2018 capital expenditures, of which $3.062 billion is for its Transmission and Distribution system alone.[7] Of that, SCE seeks $1.875 billion for Grid Modernization.[8] In its direct testimony, SCE gives three reasons for its request for ratepayer funding of Grid Modernization: (1) Enhance Safety and Reliability, (2) Enable Distributed Energy Resources (DER) Integration and Adoption, and (3) Realize DER benefits.[9]

The Commission is considering proposals in other proceedings from numerous stakeholders on what the new grid will look like or need.[10] SCE's attempt in this GRC to circumvent the stakeholder process the Commission has embarked on should be rejected.

In rebuttal, SCE attempted to re-brand its "Grid Modernization" funding requests as necessary for safety and reliability. This appears to be SCE's "go to" justification for that part of its multi-million dollar revenue requirement request. SCE was authorized ratepayer funding in both its 2012 and 2015 GRC to replace aging infrastructure.[11] In the decision on the 2015 GRC

[4] Ex. SCE-1, p. 4.

[5] Ex. ALJ-SCE-Verbal-007, A.17-01-013.

[6] Ex. ALJ-SCE-Verbal-007, A.17-01-018.

[7] SCE response to ALJ-SCE-Verbal-005, Q.1, July 24, 2017.

[8] Ex. SCE-02, Vol. 10, Summary p. 3 (2016-2020).

[9] Ex. SCE-2, Vol. 10, pp. 5-9.

[10] See Ex. ORA-9 (9A).

[11] Ex. SCE-1, p. 11.

alone, the Commission authorized SCE to collect $2.115 billion in Operation and Maintenance ("O&M") expenses and $2.912 billion in capital expenditures from customers, to ensure SCE provides safe and reliable service.[12] As discussed below and in ORA's testimony, genuine questions exist both as to whether SCE has spent these funds for the Commission authorized purposes and, even if so, about the need for the additional funds SCE now seeks under this recently re-branded claim.

ORA's recommendation of a TY 2018 revenue requirement of $5.677 billion includes this amount, and more, to ensure SCE provides safe and reliable electric service to its customers.

SCE has been authorized ratepayer funding in both its 2012 and 2015 GRCs to replace aging infrastructure.[13] In the 2015 GRC decision alone, the Commission authorized SCE to collect from customers $3.811 billion in total operating expenses and $3.4 billion in total capital expenditures to ensure SCE provides safe and reliable service to its customers.[14] ORA's recommendation of a TY 2018 revenue requirement of $5.677 billion includes this amount, and more, to ensure SCE provides safe and reliable electric service to its customers.

2. EVIDENTIARY STANDARDS AND THE BURDEN OF PROOF

The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable, and that "…no public utility shall change any rate... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[15] Thus, in ratemaking applications, like this one, the burden of proof is on the applicant utility.[16]

The ultimate burden of proof of reasonableness, whether it is in the context of test-year estimates, prudence reviews outside a particular test year, or attempts by a utility to pass costs onto ratepayers rests heavily on the utility.[17] In its decision in SCE's TY 2006 GRC, the Commission confirmed that the burden of proof is on the utility:

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[12] D.15-11-021, p. 3 and Appendix C, p. 1.

[13] Ex. SCE-1, p. 11.

[14] Ex. SCE-01, pp. 38 and 40.

[15] Public Utilities Code §§ 451, 454.

[16] *See, e.g,* D.00-02-046, mimeo, p. 36, 2000 Cal. PUC LEXIS 239.

[17] D. 00-02-046, mimeo, p. 36, 2000 Cal. PUC LEXIS 239 citing *Re Pacific Bell* (1987) 27 CPUC 2d 1, 21, D.87-12-067.

> 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. Intervenors do not have the burden of proving the unreasonableness of SCE's showing.[18]

The Commission should apply the same standard here.

3. SETTLEMENTS

ORA is not a party to any settlements at this time, and has no position on settlements other parties have reached.

4. TRANSMISSION AND DISTRIBUTION

4.1 T&D – General

SCE's Direct Testimony on Transmission and Distribution capital and expense forecasts spanned 13 different exhibits on this subject area alone. SCE's Rebuttal added at least 13 more exhibits on the subject. Given the magnitude of SCE's request, and the voluminous nature of SCE's showing, different ORA witnesses covered the various areas.

For CPUC-jurisdictional Transmission and Distribution capital expenditures for 2018, SCE forecasts $3.062 ***billion*** in nominal dollars.[19] For its 2018 Total Company Transmission and Distribution Operation and Maintenance (O&M) expenses SCE forecast $607 million.[20] SCE presents its forecast and historical Transmission & Distribution (T&D) expenses using the Federal Energy Regulatory Commission (FERC) System of Accounts. ORA's recommendations do the same.

4.1.1 Operational Overview

ORA's report focuses on risk-informed decision-making. The safety aspect of the GRC, which includes public safety, employee safety, and contractor safety, by and large, are covered as part of Operational Services in section 9 of this Brief.[21]

ORA developed its GRC forecasts and selected risk mitigation alternatives before the detailed analysis for risk and mitigation scoring was performed.[22]

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[18] D.06-05-016, mimeo, p. 7.

[19] ALJ-SCE-Verbal-005, Q. 1, SCE Pie Chart Update.

[20] ALJ-SCE-Verbal-005, Q. 1, SCE Pie Chart Update.

[21] Ex.ORA-5, p. 1.

[22] Id.

The Risk Assessment and Safety Advisory Staff of the Commission's Safety & Enforcement Division (SED) performed an in-depth review of the risk and safety aspect of SCE's GRC filing. SED's detailed findings are included in its "Risk and Safety Aspects of Southern California Edison 2018-2020 General Rate Case Application 16-09-001" report.

ORA reviewed SCE's demonstration of its detailed risk analysis process through a set of pilots in Transmission and Distribution (T&D) and non-T&D areas.[23] As discussed below, the methodology is insufficiently developed to be applied in this GRC. The methodology is still evolving and additional work is needed to develop it fully in the Safety Mitigation and Assessment Plan (S-MAP) proceeding. Therefore Commission should not base its decision on safety-related cost recovery on SCE's risk-informed decision-making analyses.

4.1.2 Risk-Informed Decision Making

The Commission initiated Order Instituting Rulemaking R.13-11-006 to develop a risk-based decision-making framework to evaluate safety and reliability improvements and revise the General Rate Case Plan for energy utilities. SCE's testimony includes its risk-informed decision-making approach, the progress and future state of its risk-informed decision-making process, and detailed risk analysis with the current risk models in selected (T&D) and non-T&D piloted areas.[24]

SCE's risk-informed decision making analysis was performed on T&D and non-T&D piloted areas to assess and develop SCE's capability to manage risk across the company. SCE performed most of the detailed analysis for risk and mitigation scoring after SCE's GRC forecasts on O&M and capital expenditures were developed and mitigation alternatives were selected. Therefore, SCE's proposed budget requests in the GRC were derived without direct input from the risk-informed decision-making process. As this process matures, SCE expects to develop project scope and selection of alternatives with the aid of the results of such analyses in future GRCs.[25] SCE also will implement all the required enhancements and modifications to its risk-informed decision-making process to align with those from the S-MAP[26] proceeding.[27]

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[23] Ex. ORA-5, p. 1.

[24] Id.

[25] Ex. SCE-14, Section III, p. 22, lns. 12-18.

[26] A.15-05-002, SCE's Safety Model Assessment Proceeding application, submitted May 2015.

[27] Ex. SCE-14, Section IV, p. 27, lns. 8 to 9.

The risk-informed decision-making framework is described in Ex. SCE-08, Volume 8, Financial Services, Audits and Enterprise Management and again in Section IV of the consolidated volume Ex. SCE-14. This framework follows a six-step process: 1) Risk Identification, 2) Risk Evaluation, 3) Risk Mitigation Identification, 4) Risk Mitigation Evaluation, 5) Decision-Making & Planning and 6) Monitoring & Reporting. The six-step process is described by SCE as consistent with the Corporation's 10-step Evaluation Model adopted by the S-MAP Interim Decision.[28] For each of the steps in the six-step process elements, SCE detailed activities of current enhancements and future enhancements. These detailed activities were summarized in a table for the SCE 2018 GRC Safety & Risk Workshop[29] and shown in the Table below.[30]

[28] Ex. SCE-14, Section IV, p. 23.

[29] SCE 2018 GRC Safety & Risk Workshop, p. 18, November 2, 2016.

[30] Ex. ORA-5, pp. 3-4.

Enterprise Risk Management Program Current Progress and Future Enhancements[31]

Steps	Progress To Date	Future Enhancements
Risk Identification	• Senior Leadership Discussions • Information Sharing with Risk Management Groups • Benchmarking and Info Sharing with Peer Utilities • Risk Lexicon and Risk Taxonomy rollout • Standard Risk Templates	• Centralized Risk Register • Systematic Information Sharing
Risk Evaluation	• Risk Evaluation Tool (RET) & Initial Pilot • Risk Calculator • Training Workshops & Tutorials	• RET Enhancements • Calibration of Risk Scores • Data Collection & Analytics
Risk Mitigation Identification	• Trenching Analysis (Pilot) • Leveraging of Bowtie Analysis for Mitigation ID • Risk Taxonomy for Drivers	• Structured Risk Mitigation Identification • Synergies Across Risk Mitigation Alternatives • Mitigation Alternatives Portfolio Development
Risk Mitigation Evaluation	• Initial Calibration • Risk Mitigation Evaluation (Pilot) • Risk Spend Efficiency (RSE) calculation (Pilot)	• Enhanced Prioritization • Enhanced Calibration • Integration of RSE into Decision-Making (Pilot)
Decision-Making & Planning	• Consistent Risk Scoring Methodology • Risk Informed Decision Making & Planning in T&D (Pilot)	• Integration with Financial Planning Process • Decision-Making Based on Mitigation Effectiveness • Transition Management • Prioritization/Optimization • OU and Cross-OU Risk-Informed Decision-Making
Monitoring & Reporting	• New Reporting Tool • Reporting to Board of Directors & Senior Leadership	• Automated CRM Platform System • Performance Metrics & Accountability Reporting Development

[31] *Ibid*.

SCE envisions in the future, the Enterprise Risk Management (ERM) team will work with the Operational Units (OU), which will partner with the Finance organization to develop cost estimates, consolidate OU mitigation plans and the Finance organization will lead cross-OU prioritization and develop final budgets.[32]

This GRC proceeding is taking place concurrently with the S-MAP proceeding. SCE plans to coordinate closely with the Commission and the intervenors to insure congruency and alignment on risk management decision making across these two regulatory processes.[33]

SCE selected a set of pilots in both T&D and non-T&D to demonstrate the detailed risk analysis process. As mentioned earlier, most of the detailed analysis for risk and mitigation scoring, which was an essential step in the pilot demonstration, was performed after SCE's GRC forecasts on O&M and capital expenditures were developed and mitigation alternatives were selected. Therefore, SCE's proposed budget requests in the GRC were derived without direct input from the risk-informed decision making process.[34]

Pilots Selected for Analysis and Conclusions

SCE performed risk analysis for eight pilot areas in T&D. The analysis is intended to show how SCE's risk framework has been applied to specific assets and activities. The current analysis is performed based on information available through March 2016. The areas included are: Overhead Conductors, Poles, Underground Structures, Circuit Breakers, Transformers, Underground Cables, 4 kilovolt (kV) Circuits and Vegetation Management.[35]

The results of the analysis are presented in the Appendix to Ex. SCE-2, Volume 1 and in Ex. SCE-14, Section V, pages 75 to 139. The results presented for each pilot area includes Risk Identification, Current Residual Risk Evaluation, Mitigation Alternatives Identification, Mitigation Risk Reduction Evaluation, Risk Spend Efficiency and Key Takeaways.[36]

SCE selected a subset of five pilot areas in non-T&D organizations to perform detailed risk analysis in order to expand beyond the T&D pilot areas. The non-T&D areas are: Customer

[32] Ex. SCE-14, Section IV, pp. 43-44.

[33] Ex. SCE-14, Section IV, pp. 27-28.

[34] Ex. ORA-5, p. 6.

[35] Ex. SCE-14, Section V, pp. 70-71.

[36] Id at p. 7.

Service Re-Platform, Power Supply Hydro, Business Resiliency, Corporate Real Estate and Corporate Security.

The information presented for each area generally includes Risk Identification and Risk Statements, Current Residual Risk Evaluation, Driver Analysis, Mitigation Alternative Identification, Planned Residual Risk Evaluation, and Risk Analysis Challenges and Next Steps.

SCE concluded from the experience and results of the modeling exercises in both the T&D and non-T&D areas that the company made significant advancements in the implementation of a risk-informed decision-making methodology. Adequate or specific data is not always available, and the company still relies extensively on subject-matter expertise (SME) for risk and mitigation evaluation. Impact dimensions, levels and calibration across dimensions and levels still need to be refined to address the risks to be mitigated.[37] [38] SCE will continue to broaden its efforts to apply the risk-informed decision-making framework to more business and operational areas of SCE.[39]

ORA reviewed SCE's testimony on risk-informed decision-making, but SCE's risk-informed decision-making methodology is a work-in-progress. SCE states that the 2018 GRC expenditure forecasts are not based on the risk-informed decision-making analysis.[40] SCE's analyses performed in the T&D and non-T&D pilot areas are essentially exercises to evaluate the risk-informed decision making methodology being developed up to March 2016. SCE performed these analyses after the GRC expenditure forecasts were derived, and therefore the use of the risk-informed decision-making methodology makes an insignificant contribution to SCE's 2018 GRC funding proposals.

SED Assessment

SED performed an in-depth review of the risk and safety aspect of SCE's GRC filing. The detailed findings are provided in the report "Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001. SED describes SCE's risk-based decision-making approach as still evolving and most of the steps in the framework have yet to be

[37] SCE 2018 GRC Safety & Risk Workshop, p. 23, November 2, 2016.

[38] No quantification as to the level of SME was cited by SCE.

[39] Ex. SCE-14, Section VII, p. 171.

[40] Ex. SCE-14, Section III, p. 22, lines 12-14.

implemented. SED found that the risk-spend efficiency[41] metric has not matured enough to derive the 2018 GRC expenditure proposals, and much work remains to develop it fully. SCE is categorizing portions of many programs' spending as safety-related, even though they relate more to issues of customer satisfaction or electric service reliability in contrast to safety.[42] SCE's risk-informed decision-making methodology is not ready as a basis for determining reasonableness of safety-related program expenditure requests.[43] The current GRC is essentially a transitional case in the use of SCE's risk-informed decision-making methodology.[44]

ORA agrees with SED's assessment and recommends that the Commission not base its decision on safety-related cost recovery on SCE's current risk-informed decision-making analyses. The current methodology is inadequately developed to provide meaningful cost guidance in this GRC. The methodology is still evolving and much work is needed to develop it fully in the S-MAP proceeding to be applied in future GRCs.[45]

4.1.3 Safety and Reliability Investment Incentive Mechanism

SCE states that "[n]othing is more important at SCE than protecting the safety of the public and of our employees and contractors."[46]

The Corporate Health and Safety (CHS) organization provides guidance, governance and oversight of SCE's safety program and activities. CHS is responsible for overseeing SCE's corporate safety program in electrical safety, industrial ergonomics, industrial hygiene and contractor safety.

CHS requests $5.688 million (constant 2015 dollars) of O&M expenses in FERC Account 925 for the 2018 Test Year.[47] ORA has no comment on this proposal at this time.

[41] It is defined as risk reduction (difference between pre-mitigation and post-mitigation risk scores) divided by the cost of the risk mitigation program or project.

[42] SED Report, p. 7.

[43] SED Report, p. 6.

[44] EX.ORA-5, p.9.

[45] Ex. SCE-14, Section IV, p. 27, lns. 5 to 11, and p. 28, lns 1 to 2.

[46] Ex. SCE-14, Section II, p. 3, lns. 20-21.

[47] Ex. SCE-07, Vol. 04, p. 1, lns. 19-20.

4.2 T&D -- Customer Driven Programs

4.2.1 Capital - Adjustments to Customer Driven Projects

Running the distribution system of an electric utility requires that a multitude of capital projects be undertaken associated with installing, inspecting, maintaining, replacing and moving various types of distribution equipment and structures. The capital projects undertaken under the Customer Driven Programs are a subset of these total activities and focus on work related to responding to requests from SCE's customers. Such requests typically include connecting new customers to the distribution system, meeting customer requests to underground certain overhead facilities, and costs incurred to relocate existing SCE facilities to meet customer needs.

There are 11 project categories that make up the Customer Driven area. Of these 11 categories, ORA recommends adjustments to six of them. However, five of these six adjustments are due to inputs from other ORA witnesses that differ from SCE's inputs. Thus, five of these six capital categories resulted in adjustments due to data inputs that were derived outside of Exhibit ORA-08. Only one of ORA's recommended adjustments, addressing issues with SCE's Rule 20A undergrounding program, are solely attributable to the analyses included in Exhibit ORA-08.

Exhibit ORA-08, includes detailed discussions of ORA's Rule 20A adjustments. SCE presents its Customer Driven testimony in Ex. SCE-02, Volume 02. References to SCE's Rebuttal testimony refer to Ex. SCE-18, Vol. 02. All references to SCE's Direct and Rebuttal testimony in the remainder of this section of this Brief refer to those specific SCE exhibits.

4.2.2 Rule 20A Undergrounding Program

SCE states the following regarding Rule 20A projects:

> Under Rule 20A, each governmental agency in SCE's service territory is allocated a portion of SCE's Rule 20A capital budget to be used for overhead conversions based on a system-wide formula. Once a governmental agency has accumulated enough allocation to execute a conversion, the agency selects the locations within its jurisdiction where overhead facilities will be converted. Generally speaking, Rule 20A conversion projects are among the most complex projects within the Distribution Business Line. Each project requires coordination with multiple utilities and customers, and necessitates acquiring multiple permits based on the magnitude and duration of the projects.

Historically, ORA has found that recorded Rule 20A expenditures have typically been less than what was authorized. In prior GRCs, ORA has recommended lower funding for Rule

20A projects compared to SCE because recorded expenditures were usually less than had been authorized.

In SCE's TY 2012 GRC, the Commission took note of Rule 20A expenditures stating:

> The Commission is aware that SCE has committed to spend $161 million to complete Rule 20A undergrounding projects that it already started and which could take up to five years to complete. However, we are concerned that SCE consistently continues to spend less than authorized by the Commission for Rule 20A undergrounding conversions.
>
> Undergrounding electrical systems have both safety-related and reliability advantages, besides aesthetical value. In order to encourage more underground conversions, we will grant SCE's request for funding for 2011 and 2012 at the 2009 level of $29.507 million plus escalation, which SCE calculates as $30.594 million in 2011 and $31.332 million in 2012. However, going forward we expect SCE to fully support conversion projects within the authorized funding for undergrounding conversions.[48]

On page 58 of its Direct testimony, ORA presented Table 8-13, which is reprinted below. Lines 1 through 3 of Table 8-13 show the difference between authorized Rule 20A expenditures and actual recorded expenditures for the 5-year period 2012 through 2016. (Note that on Line 2, recorded expenditures are shown for 2016.) Line 3 shows, at no time did SCE's Rule 20A expenditures equal, or exceed, the amounts that were authorized. SCE failed to spend the amounts authorized in 2014, 2015 and 2016. In spite of the strong language included in the TY 2012 GRC decision (quoted above), and in spite of the fact that the Commission adopted (in the last GRC) an ORA proposal to adjust authorized Rule 20A expenditures to account for prior underspending, SCE has continued to spend less than what was authorized for those years.

[48] D.12-11-051 at p. 166.

Table 8-13
CUSTOMER DRIVEN PROJECTS
RULE 20A CAPITAL EXPENDITURES
(Thousands of Nominal Dollars)

Line #	Category						Forecast					
							2017			2018		
		2012	2013	2014	2015	2016	SCE	ORA	SCE > ORA	SCE	ORA	SCE > ORA
		(a)				(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Authorized Rule 20A Expenditures 1/	$31,332	$32,288	$22,676	$23,284	$23,726						
2	Recorded Rule 20A Expenditures	$15,768	$31,954	$17,910	$13,217	$19,575						
3	Difference	$15,564	$334	$4,666	$10,067	$4,150						
4	Total Underspent per D.15-11-021 (2014 Through 2016)				$19,117							
5	Forecast Rule 20A Expenditures						$23,086	$23,086		$23,640	$23,640	
6	Adjustment Due to Allocation of Underspent Amount							$9,569			$9,569	
7	Total Rule 20A Expenditures						$23,086	$13,517	$9,568	$23,640	$14,065	$9,568

= 2016 recorded

1/ 2012 authorized amount comes from page 169 of Decision 12-11-051
2013 authorized amount is derived by increasing 2012 by the authorized attrition amount of 3.00% (page 500 of Decision 12-11-051)
2014 authorized amount comes from page 85 of Decision 15-11-021
2015 authorized amount comes from page 85 of Decision 15-11-021
2016 authorized amount is derived by increasing 2015 by the authorized attrition amount of 2.00% (page 390 of Decision 15-11-021)

As shown on Line 4 in the above table, SCE has spent $19.117 million less than what was authorized for the three years approved in the last GRC (2014 through 2016). ORA considered several options regarding how to respond to this continuing problem of underspending Rule 20A funds. ORA's first inclination was to simply scale back SCE's forecast in order to reflect the likelihood that SCE would underspend its request. However, the language in past GRC decisions makes it clear that the Commission is not usually inclined to simply scale back Rule 20A expenditures. Therefore, ORA recommends that the Commission adopt SCE's 2017 and 2018 forecasts for Rule 20A expenditures, but that it also incorporate an adjustment to reflect the underspending that occurred in 2014 through 2016. ORA proposed this in the last GRC, and the Commission adopted ORA's proposal.[49] As shown in Line 6, ORA includes an adjustment of $9.558 million in each of the years 2017 and 2018 (each year's proposed offset represents one half of the underspent $19.117 million).

In the most recent PG&E GRC proceeding, the Commission adopted a procedure whereby PG&E is required to track the unspent Rule 20A expenditures in a one-way balancing account so that the unspent funds are spent on Rule 20A projects in current and future years.[50] The procedure ORA recommends in this current SCE proceeding (and was adopted in the prior SCE GRC) is akin to the adopted PG&E mechanism -- both seek to ensure that ratepayers are protected from paying for authorized Rule 20A capital projects that have been deferred. This protection results from requiring the utilities to use prior unspent Rule 20A funds to offset future forecasts.

On page 11 of its Rebuttal Ex. SCE-18, Vol. 2, SCE criticizes ORA's Rule 20A analyses and recommendations. SCE's alleges (at line 12 on page 11) that 18 cities will receive zero Rule 20A allocations if ORA's recommendations were to be adopted. However, SCE fails to note that its own Rule 20A recommendations also would result in a number of zero allocations. In response to Data Request ORA-SCE-239-GAW, Question 1.b, SCE states that its own recommended Rule 20A funding level for 2017 would result in seven cities receiving zero allocations. SCE does not specify for which year these zero allocations would occur.

[49] D.15-11-021, p. 90.

[50] D.17-05-013, p. 2.

In its Direct testimony (page 39, lines 8 and 9), SCE states that it allocates "a portion of SCE's Rule 20A capital budget." The only 2017 Rule 20A capital budget the Commission adopted is the one included in SCE's 2015 GRC application, and which remains unchanged. Therefore, ORA presumes that SCE refer to some unspecified period beyond 2017 when SCE states that cities will receive zero allocations. Adding to SCE's confusing allegations is the fact that ORA actually recommends that the Commission adopt SCE's forecast.[51] While it is true that ORA recommends an offset to reflect the fact that SCE has underspent Rule 20A projects, ORA is not recommending that SCE curtail any Rule 20A projects. Similar to the PG&E one-way balancing account procedure, ORA's Rule 20A recommendations only seek to ensure that previously authorized Rule 20A expenditures, unspent and deferred by SCE, be used in this current GRC to offset SCE's proposed Rule 20A forecasts. The net result is that ORA would expect that its recommendations for Rule 20A expenditures would result in the same number of cities receiving zero allocations as would SCE's recommendations.

SCE next alleges that it has changed the manner in which it forecasts future Rule 20A expenditures. Beginning on line 8 of page 12 of its Rebuttal, SCE acknowledges that it has previously spent less than was authorized for Rule 20A projects. However, it now argues that its revised forecast methodology will better align future estimates with actual expenditures. ORA is skeptical, noting that only once in the last five recorded years have recorded Rule 20A expenditures reached the $23+ million expenditure levels SCE forecast for 2017 and 2018. More importantly, SCE's allegations concerning its forecasting methodology are simply moot. As mentioned previously, ORA recommends that SCE's Rule 20A forecasts be adopted. Since ORA and SCE are in agreement regarding the unadjusted amount of total Rule 20A expenditures, it is actually immaterial if SCE has changed its forecasting methodology. The only portion of the Rule 20A forecasts that is in dispute is whether or not SCE should be required to use previously unspent Rule 20A funds to offset the current forecasts.

Next, on page 13 of its Rebuttal, SCE provides Table I-8. As discussed earlier, this table is purported to show that there are currently 46 projects that are currently in progress for the 2017 through 2018 period, with a total estimated cost of $107 million. Beginning on line 8 of

[51] See ORA-08, p. 59, lns. 18 and 19.

page 14, SCE outlines some of the uncertainties that are associated with predicting these Rule 20A projects:

> These projects are also subject to delays that can be caused by joint utilities, easement acquisition, or issues triggered by the sponsoring cities with regard to permit requirements and construction scheduling. Additionally, the sponsoring cities may have issues that prevent them from moving forward with projects at all. For example, many cities are subject to staffing constraints, and often city-driven public works projects are prioritized over Rule 20A projects. Another issue that impacts the rate of identified projects is that there are some cities with large amounts of accruals that have not been interested in proposing undergrounding projects. These cities continue to accrue a balance, which effectively decreases the amount of the budget that is allocated to other cities with a desire to propose undergrounding projects.

Given the inherent uncertainty associated with the timing and costs of Rule 20A projects, ORA is concerned regarding the accuracy of the data contained in Table I-8. ORA is especially concerned about the inference contained in the title ("2017-2018 In-Progress Projects") that suggests that these 46 projects will be completed in the next two years. In order to obtain additional details regarding Table I-8, the ALJs issued Verbal Data Request 006, Question 2, which asked:

> Referring to Table I-8 on page 13 of SCE-18, Volume 2, please indicate what the impact would be to each of the in-progress projects, if ORA's recommendation to adopt a financial penalty is adopted by the Commission.

In response to the ALJs' verbal request, SCE provided the table shown below, which is essentially an expanded version of Table I-8. The last column in this table alleges that 18 capital projects would be delayed if ORA's Rule 20A recommendations were adopted; if only those Rule 20A projects that have 2017 starting dates are considered, SCE claims that 14 projects would be delayed. For a variety of reasons, ORA believes the table provided to the ALJs is not only misleading, it is in fact wrong in many instances.

First and foremost, SCE's table appears to assume that ORA is advocating that Rule 20A projects be delayed. While it is true that ORA has recommended an offset to reflect the fact that SCE has underspent Rule 20A projects, ORA is <u>not</u> recommending that SCE curtail any Rule 20A projects. Similar to the PG&E one-way balancing account procedure, ORA's Rule 20A recommendations only seek to ensure that previously authorized Rule 20A expenditures, unspent

and deferred by SCE, be used in this current GRC to offset SCE's proposed Rule 20A forecasts. The net result is that ORA would expect that its recommendations for Rule 20A expenditures would result in no more project delays (if any) than would SCE's own proposed forecasts.

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Region	ID	City/County	ROM Project Estimate	Earliest Construction SCE Forecast	Earliest Construction ORA Forecast	Years Delayed
North Coast	2.02	Unicorp. Santa Barbara	$1,600,000	2017	2018	1
	2.16	Camarillo (K St. from Cedar to Oak)	$400,000	2017	2019	2
	2.17	Camarillo (Las Posas from Marcos to Antonio	$1,700,000	2017	2019	2
North Coast Total			**$3,700,000**			
San Joaquin	4.03	Visalia	$2,600,000	2017	2017	
	4.04	Delano	$1,500,000	2017	2017	
San Joaquin Total			**$4,100,000**			
	8.28	Unicorp. L.A. (Topanga Cyn)	$3,500,000	2017	2017	
	8.29	Unicorp. L.A.	$2,100,000	Project Completed in 2017		
	8.30	Unicorp. L.A.	$1,800,000	Project Completed in 2017		
Metro East Total			**$7,400,000**			
Metro West	1.08	Cudahy	$1,700,000	2017	2017	
	1.24	Long Beach	$5,200,000	2017	2017	
	1.28	Norwalk	$5,400,000	2017	2017	
	1.39	Bell Gardens	$3,300,000	2017	2017	
	1.41	Torrance (Hawthorn Blvd.)	$2,900,000	2017	2017	
	1.42	Torrance	$1,800,000	2017	2017	
	1.43	West Hollywood	$1,900,000	2017	2017	
	1.45	Redondo Beach	$1,100,000	2017	2017	
	1.47	Cerritos	$900,000	2017	2018	1
	1.48	Seal Beach	$500,000	2017	2017	
Metro West Total			**$24,700,000**			
San Jacinto	7.11	Murrieta	$1,000,000	Project Completed in 2017		
San Jacinto Total			**$1,000,000**			
Metro East	8.11	San Marino	$920,000	2017	2018	1
	8.15	Whittier (Broadway)	$3,200,000	2017	2018	1
	8.21	South El Monte	$2,300,000	2017	2017	
	8.24	Montebello	$3,300,000	2017	2019	2
	8.36	Baldwin Park	$3,000,000	2017	2017	
	8.38	South Pasadena	$2,600,000	2017	2017	
	8.31	Glendora	$1,200,000	2017	2017	
	8.32	Montclair	$900,000	2017	2019	2
	8.33	Rancho Cucamonga (Arrow)	$2,800,000	2017	2019	2
	8.34	Rancho Cucamonga (Baseline)	$1,500,000	2017	2019	2
	8.35	La Puente	$3,000,000	2017	2017	
	8.37	La Verne	$3,800,000	2017	2017	
	8.40	Whittier (Greenway Tr - 5 Pts)	$1,200,000	2017	2018	1
	8.41	Rosemead	$3,130,000	2017	2018	1
Metro East Total			**$32,850,000**			
Desert	9.03	Palm Springs	$2,000,000	2020	2021	1
	9.06	Unicorp. San Bernardino	$3,400,000	2017	2017	
	9.21	Redlands	$2,500,000	2017	2017	
	9.23	Apple Valley	$730,000	2017	2017	
	9.24	Rialto	$1,400,000	2018	2019	1
Desert Total			**$10,030,000**			
Rural	3.05	Barstow	$2,000,000	2018	2019	1
	3.06	29 Palms	$1,400,000	2017	2017	
Rural Total			**$3,400,000**			
Orange	8.2	Whittier	$4,200,000	2017	2018	1
	6.22	Fullerton (PH 2A / 2B)	$1,400,000	2017	2017	
	6.23	Huntington Beach	$5,500,000	2017	2019	2
	6.24	Brea	$1,900,000	2017	2017	
	6.25	Newport Beach	$4,800,000	2018	2019	1
	6.26	Stanton	$2,400,000	2017	2017	
Orange Total			**$20,200,000**			

Second, ORA questions how reasonable and realistic it is to include a column that shows the earliest date for construction for Rule 20A projects (in the above table it is the third column from the right). ORA agrees Rule 20A capital projects are commonly delayed and in previous years, Rule 20A projects have taken as long as 14 years to complete. It is misleading (and probably wrong), however, to show purported delays that are based on an unrealistic starting date.

Third, other Rule 20A data obtained from SCE indicate that some of the information provided in the table for the ALJs is not correct. On SCE's website, SCE maintains a spreadsheet titled "SCE Underground Conversion Projects," that provides, among other items, columns of data on Construction Start Dates, Construction End Dates, and the Project Status for each of its underground conversion projects.[52] For each of the Rule 20A projects contained in the table provided to the ALJs, ORA was able to find the corresponding project listed in the spreadsheet found on SCE's website. Comparing the data contained in these two sources, ORA found the following discrepancies among the 14 Rule 20A projects that SCE has claimed will be delayed from their 2017 start:

- SCE's website spreadsheet indicates that three of these 14 projects have already started construction.
- SCE's website spreadsheet shows that four of the 14 projects are not even scheduled to begin construction until 2018.
- SCE's website spreadsheet shows that three of the 14 projects had not progressed to a stage where a construction starting date had been determined.

The information contained in Table I-8 of SCE's Rebuttal (along with the additional information contained in the expanded version of Table I-8 that was provided to the ALJs), is not relevant and is essentially moot. Since ORA is not recommending that any Rule 20A projects be curtailed, there will be no delays to any of these projects. Furthermore, even if one was to ignore the fact that ORA has not recommended any Rule 20A project curtailments, ORA has demonstrated that the table provided to the ALJs is designed in a misleading manner, and contains data that is inconsistent with other SCE information. The Commission should give no

[52] That spreadsheet can be found here: https://www.sce.com/wps/wcm/connect/5e534575-4d74-4d7c-96b1-21521fab46ed/SCE_UGConversionProjectSummaryQ42016.pdf?MOD=AJPERES.

weight to SCE's allegations that an adoption of ORA's recommendations would result in delays to various Rule 20A projects.

4.2.3 O&M

SCE's Distribution Maintenance and Inspection organization performs repairs, planned and unplanned inspections and maintenance on the electrical equipment and structures that make up SCE's distribution grid system.[53] In its Application, SCE forecast $159.968 million for Distribution Maintenance and Inspection expenses.[54] SCE says it developed its forecast by using its 2015 recorded adjusted expenses as a basis for proposed TY projects and activities. ORA does not oppose SCE's estimate.[55]

4.3 T&D System Planning

4.3.1 General

SCE's direct testimony on System Planning seeks $771 million in ratepayer funding for capital expenditures.[56] ORA recommends ratepayer funding of $600.188 million.[57]

SCE says its request for program and project funding for T&D System Planning is based on SCE's annual planning processes, customer requests to interconnect generation, and requests for non-standard service.[58] The majority of SCE's requests relate to the planning processes where estimates are driven by forecasts of increasing capacity needed to serve new customers, or increased load from existing customers, while meeting system reliability and integrating DER.[59] According to SCE's direct testimony, approximately $79.8 million, or 10%, of SCE's total request for system planning is driven by the need to "enable DER."[60]

SCE's direct testimony in Exhibit SCE-2, Volume 3R discusses 18 programs which SCE grouped into four areas: (1) Transmission and Interconnection Planning Projects; (2)

[53] Ex. SCE-2, Vol. 4, p. 1.

[54] Ex. SCE-2, Vol. 4, p. 2.

[55] Ex. ORA-7, p. 9.

[56] Ex. ORA-9A (and Ex. ORA-9), p. 1, citing Ex. SCE-2, Volumes 3 and 10. The $771 million figure does not adjust for Operational and Service Excellence savings.

[57] Ex. ORA-9A (and Ex. ORA-9), p. 3.

[58] Ex. SCE-2, Vol. 3R, p. 26.

[59] Ex. ORA-9A (and Ex. ORA-9), p. 61.

[60] Ex. ORA-9A (and Ex.ORA-9), p. 54, Table 9-2; Ex. ORA-9-WP, p. 221.

Distribution and Sub-transmission Planning Programs and Projects; (3) System Improvement Programs; and (4) Customer Requested Projects.[61] SCE did not provide the historical CPUC jurisdictional expenditures for each of the 18 programs / projects it included in its direct testimony. [62]

- **Transmission & Interconnection Planning Projects**

The projects SCE lists as "Transmission and Interconnection Planning" (TIP) projects include FERC jurisdictional expenditures.[63] ORA sent data requests to SCE to try to determine how SCE's forecast TIP project expenditures compared to historical expenditures since SCE had not provided this information in testimony or workpapers.[64]

With what information ORA was able to re-construct, ORA concluded that SCE's forecast expenditures are reasonable compared to SCE's past expenditures. ORA's only adjustment was to SCE's forecast for 2016 to reflect SCE's actual 2016 expenditures.[65]

- **Distribution and Sub-Transmission Planning Programs and Projects**

Distribution Plant Betterment

ORA proposes no adjustments to SCE's 2017 and 2018 forecast. ORA recommends the Commission adopt 2016 recorded costs of $23.289 million.[66]

- Distribution Circuit Upgrades

ORA proposes no adjustments to SCE's 2017 and 2018 forecast. ORA recommends the Commission adopt 2016 recorded costs of $49.924 million.[67]

New Distribution Circuits

Expenditures for the new distribution circuits program include work for WBS[68] CET-PR-LG-CI.[69] SCE explains that the scope of work within this WBS changed. Prior to 2016, this

[61] Ex. SCE-2, Vol. 3 R, p. 50.

[62] Ex. ORA-9A (and Ex. ORA-9), p. 63.

[63] Ex. ORA-9A, pp. 66-68 (and Ex. ORA-9), pp. 65-67.

[64] Ex. ORA-9A, p. 67, (and ORA-9, p. 66).

[65] Ex. ORA-9A, p 68 (and Ex. ORA-9, pp. 66-67).

[66] Ex. ORA-9, p. 73 (and Ex. ORA-9, p. 72).

[67] Ex. ORA-9A, p. 73 (Ex.ORA-9, p. 72).

WBS reflected "new distribution circuits as part of three types of projects: new substation projects, substation capacity increase projects, and projects with unique drivers."[70] Starting in 2016, this WBS only includes one different type of work: "standalone circuit projects."[71] Descriptions of the three historical sources of new circuits correspond to types of Substation Expansion projects, and SCE states that expenditures for those new circuits are included in those programs.[72] SCE describes the new scope of work in this WBS as "[t]he new standalone DSP circuits in this category have been identified to solve distribution needs diagnosed during the distribution planning process and are intended to meet the requirements outlined in our Distribution Planning Criteria and Guidelines. Besides load growth driven needs, new standalone DSP circuits have been identified for construction due to high forecast DER penetration and 4 kV substation eliminations."[73]

ORA recommends that the Commission adopt 2016 recorded costs of $12.986 million in contrast to SCE's 2016 forecast of $33.312 million. SCE's recorded 2016 costs are less than 50% of SCE's forecast. ORA does not oppose SCE's increased forecast for 2017 and 2018 for distribution upgrades, which SCE says are, in part, due to declining costs for new circuits. For these reasons, ORA proposes adjustments to SCE's 2017 and 2018 forecast.

For 2017, ORA proposes using SCE's 2016 forecast of $33.312 million. Adoption of this budget for the new stand-alone program is actually less than the historical cost of the three programs now included in a different WBS.[74] For 2018, ORA applied its 2018 escalation rate, resulting in a recommendation of $34.108 million for that year.[75]

Substation Expansion Projects

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[68] SCE uses "WBS" elements to classify types of work for tracking purposes.

[69] Ex. SCE-2, Vol. 3R, Figure IV-17, p. 64. RO model input for this program is at RO Model ID 163 and 164, as the forecast is provided for two regions: Orange (ORA) and Metro West (MTW).

[70] Ex. SCE-2, Vol. 3R, p. 63, Figure IV-17.

[71] Ex. SCE-2, Vol. 3R, p. 63, Figure IV-7.

[72] Ex. SCE-2, Vol. 3R, p. 64, footnote 116.

[73] Ex. SCE-2, Vol. 3R, pp. 64-65.

[74] Ex. ORA-9A, p. 64, Table 9-3. The lowest historical cost was $39.687 million in 2015.

[75] Ex. ORA-9A, p. 75 (Ex. ORA-9, p. 74).

One of the projects in SCE's forecast involves a new substation, the "Safari" substation to be located in Irvine near the El Toro "Y", "one of the busiest [freeway] interchanges in the world."[76] An article in the Orange County Register entitled "Edison's substation project in Irvine at 'stalemate'" described opposition to the project and concluded with the following: "'We're not giving up, Jane Klassen said. 'We're using every avenue we can to find a resolution, but that's hard to do when you can't get anyone to talk to you.'"[77] In response to ORA's discovery, SCE responded that "the project has been delayed by approximately one year. SCE cannot project an operating date until the current issues have been resolved."[78] A second Orange County Register article entitled "Irvine refers controversial Edison substation project to state" stated that "The City Council voted 3-2 in favor of referring the issue to the California Public Utilities Commission."[79] SCE's 2016 recorded expenditures for the substation portion of the project were $2.3 million compared to a forecast of $19.6 million, which is consistent with the project delay.[80]

SCE's testimony forecasts this project at $67.458 million and an operating date of June 2019.[81] ORA forecasts that this project will not be completed and booked to plant in the current GRC period.[82] Rather than removing all forecast costs, ORA only adjusted SCE's 2017 forecast from $8.5 million to zero, in addition to adjusting the 2016 forecast to 2016 recorded expenditures.[83]

4kV Programs

SCE requests funding for two programs focused on the lowest voltage distribution assets, those 4.8 kV and below, which are collectively referred to as "4kV" equipment: the overload

[76] The El Toro "Y" is the southern interchange between the Interstate (I)-5 and I-405 freeways. See https://en.wikipedia.org/wiki/El_Toro_Y .

[77] http://www.ocregister.com/articles/city-740819-edison-project.html Jan. 11, 2017.

[78] Ex. ORA-9A, p. 76, footnote 219, citing SCE response to data request ORA-SCE-136-TCR, Q. 2.

[79] http://www.ocregister.com/articles/city-747369-edison-land.html Mar. 23, 2017.

[80] Ex. ORA-9A, p. 76, footnote 221, citing SCE response to data request ORA-SCE-Verbal-44. This project has a substation component with a unique WBS number, CET-ET-LG-SU-751600, and a component to build new circuits under a generic WBS number, CET-ET-LG-CI-MTE, which is used for other distribution circuit work. ORA was able to review only recorded costs for CET-ET-LG-SU-751600. See workpapers supporting SCE-2, Vol. 3R, book C, pp. 312-319.

[81] Ex. SCE-2, Vol. 3R, p. 67.

[82] Ex. ORA-9A, p. 76 (and Ex. ORA-9, p. 75).

[83] Adjustments to the RO model were made to RO Model IDs 162 and 212.

driven cutover (4 kV Cutover) program and the 4 kV substation elimination (4 kV Elimination) program.[84] The 4 kV Cutover program is a load growth based program that provides relief for circuits forecast to experience overloads.[85] The 4 kV Elimination program seeks to eliminate an entire category of assets that make up 25% of SCE's distribution circuits for a multitude of reasons other than a forecast overload.[86] This program has more in common with programs in the Infrastructure Replacement volume, which focuses on "programs that replace equipment based on engineering analysis."[87] In fact, in prior rate cases 4 kV programs were included in the Infrastructure Replacement volume.[88]

ORA's testimony provides the following for each 4 kV program: a concise overview, a history, and ORA's concerns regarding SCE's current request.[89] SCE's forecast for both programs in the current case would provide a substantial increase compared to historic expenditures, and SCE's failure to justify these increases is the focus of ORA's recommendation to continue funding the programs at historical levels. ORA's central argument is that SCE changed its forecasting methodology and failed to provide information on cutover unit costs that would allow the CPUC and parties to compare the forecast scope to historical scope. As stated by ORA's witness in hearings, this led to the current situation in which it is impossible to determine if SCE's 4 kV program requests are to perform "more [4 kV cutover] work or that the costs went up because you're asking for more money to do the same thing."[90]

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[84] Ex. ORA-9A, p. 76, footnote 224, citing SCE response to data request ORA-SCE-208-TCR, Q.1.

[85] Refer to Ex. SCE-2, Vol. 3R, pp. 86-88. The fact that this is a "load growth" program is indicated in the WBS number, (WBS CET-ET-**LG-**4C).

[86] Ex. ORA-9A, p. 75.

[87] Ex. SCE-2, Vol. 8, p. 1. The fact that this is a "infrastructure replacement" program is indicated in the WBS numbers, WBS CET-ET-**IR-**4C and CET-ET-**IR**-SR, where the "IR" stands for infrastructure replacement.

[88] 4 kV programs were included in Ex. SCE-3, Vol. 4 as part of "Infrastructure Replacement Programs" in the 2015 GRC, A.13-11-003. In the 2012 GRC, A.10-11-015, 4 kV programs are also discussed as part of Infrastructure Replacement Programs, but this was provided in Ex. SCE-03, Vol. 03, Part 03, Chapters I-II.

[89] Ex. ORA-9A. For the 4 kV Cutover program, see pp. 76-80. For the 4 kV Elimination program, see pp. 80-85.

[90] 18 RT, p. 2687, ll. 9-11 (Roberts/ORA).

The process of cutting-over circuits is a fundamental component of both programs.[91] In addition, the cost of cutting-over circuits is the primary cost driver for both 4 kV programs such that the issue of cutover unit costs is central issue for both programs.[92] SCE's forecast cutover unit cost doubled in the TY 2015 GRC compared to the TY 2012 GRC, and this increase was adopted because no party challenged the increase.[93] SCE changed the unit of scope for 4 kV programs from amp cutover to transformers cutover. SCE was not able to provide historical versus forecast data on either amps or transformers so ORA used the only metric provided for all years: circuits cutover. In rebuttal, SCE critiqued ORA's circuit based analysis, but did not address ORA's fundamental concern by providing other data that would allow a comparison of forecast scope and unit costs to historical values, for example using either amps or transformers cutover.[94] SCE asserted that using transformers as the basis of its forecasts was more accurate since "the number of transformers replaced is a better indicator of the scope of work needed," but failed to provide any evidence supporting this assertion.[95] In hearings, SCE's witness stated in re-direct why it was "very, very difficult" to retroactively determine actual amps cutover,[96] but this misses the point. SCE used amps-cutover to forecast 4 kV Cutover costs since at least 2010 and it should have collected data on actual amps cutover to measure the success of the program.[97]

SCE did not perform an analysis to determine if amps or transformers are better correlated to project costs.[98] Cross examination of SCE's witness, however, showed that the number of transformers is a poor predictor of cutover project costs, whether cutovers are driven

[91] The 4 kV Elimination Program is a two-part program to first, cutover all customers on 4 kV circuits to higher voltage circuits, and then to remove the 4 kV stations and remediate the station locations. See Ex. SCE-2, Vol. 3R, p. 89.

[92] Cutover costs are 95% of 4 kV Elimination projects. See 10 RT., p. 1365, Takayesu/SCE.

[93] Ex. ORA-9A, p. 78.

[94] Ex. SCE-18 Vol. 3, pp. 22-24.

[95] Ex. SCE-18 Vol. 3, pp. 22-24.

[96] 11 RT, pp. 1480-1481, Takayesu/ SCE.

[97] See ORA-9-WP, Book 1, p. 286, Table II-24.

[98] On cross examination of SCE's witness, ORA asked "Has Edison performed an analysis of recorded data to determine if amps or number of transformers are better correlated to cutover project costs?" SCE's answer at page 1364 was "No. We have not performed an analysis." RT Vol. 10, pp. 1362-1364, Takayesu/SCE.

by overloads or substation elimination.[99] During re-direct, SCE's witness stated that using transformers is a "reasonably accurate predictive tool for estimating project costs" because "the transformer is a physical asset. That's the portion that costs money."[100] While ORA agrees that transformers cost money, so do many other materials, particularly where a 12 kV or 16 kV lines is not already on the same poles. Labor to plan, design, and construct the cutovers also costs money.

SCE is not able to describe how much of the total cost of a cutover project is due to transformer costs.[101] Finally, SCE's witness' unconvincing explanation of why transformers provide a better basis for forecasts contradicts SCE' TY 2015 GRC workpapers, which explained that the historical practice of forecasting based on transformers was terminated in favor of amps.[102]

Prior to the cross examination of ORA's witness, ORA provided a corrected version of its testimony (Ex. ORA-9A), including corrections to ORA's original 4kV Cutover program testimony.[103] One outcome of these corrections is that the comparison of scope and unit costs based on circuits cutover is more robust since all years with complete data are included.[104] While that comparison is more accurate if 2016 data is excluded, data was also provided inclusive of 2016 to show that it did not impact the overarching point: SCE's forecast unit cost for 4 kV Cutovers is more than twice the historical average cost per circuit.[105]

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[99] Ex. ORA-103, pp. 45 and 51.

[100] 11 RT, pp. 1481-1482, Takayesu/SCE.

[101] SCE's response to the question "What percentage of the cost is the transformer cost?" was "That I don't know." See 10 RT, p. 1362, Takayesu/SCE.

[102] "To estimate the cost of cutover project **further in the future than one year**, the cost **must** be based on the number of amps by which each circuit is forecast to be overloaded," Ex. ORA-103, p. 33, emphasis added. SCE's explanation is at RT Vol 10, pp 1369-1370, Takayesu/SCE.

[103] Ex. ORA-9A, pp. 80-81.

[104] ORA's original analysis excluded data for 2013 and 2016 because very few circuits were cutover in those years. In the revised analysis, only 2016 data should use with caution because it does not include a majority of projects performed that year. As explained in Ex. ORA-9A, p. 79, SCE provided cost data on only 16 of the 20 projects performed that year.

[105] Using data from Ex. ORA-9A, p. 80. Figure 9-13, the forecast unit cost of $1.35 million per circuit is 2.1 times higher than 2006-2016 average of $0.638 million, and 2.3 times higher than the 2006-2015 average of $0.580 million per circuit.

As stated by ORA's witness in hearings, ORA is not taking a position on whether amps, transformers, or circuits provide the best basis upon which to forecast 4 kV project costs.[106] ORA's concern is that by changing methodologies without providing a means to compare the scope of work forecast and completed, SCE has made it impossible to determine if its proposed increase in expenditures is reasonable. The most obvious mitigation once ORA raised this concern in opening testimony would have been for SCE to compile data on transformers cutover historically, or to provide a forecast of amps to be cutover. SCE had over seven months from the time ORA first raised this question in discovery and ten weeks from the time ORA clarified its concern in opening testimony to provide a means to justify its request in rebuttal by responding to ORA, but SCE did not.[107] As a result, there is insufficient evidence to address the central question of whether SCE's proposed increased funding for 4 kV programs is based on accelerating the programs by performing more work (which could be measured in terms of amps, transformers and circuits if SCE had provided the data) or if SCE's proposal just seeks more funding to maintain the status quo. Lacking such information, the only reasonable action if the CPUC chooses to continue these programs is to provide status quo funding for status quo scope of work, consistent with ORA's recommendation.[108]

ORA's analysis of SCE's 4 kV Cutover Program indicates that SCE has modified its forecast methodology such that it is extremely difficult to determine the reasonableness of its request. Whether evaluated using the historical basis of amps or the proposed basis of transformers; SCE's forecast is excessive compared to historical expenditures. SCE has not meet the burden of proof for this rate increase required by Public Utilities Code section 454.

Given that SCE has failed to justify the reasonableness of its forecast, ORA recommends that the CPUC adopt the same budget it approved in D.15-11-021, $26.736 million, adjusted for inflation using ORA forecast escalation, or $27.615 million in 2017 and $28.275 million in 2018.

SCE should be held accountable for performing a reasonable scope of cutovers for the authorized funding, particularly given the un-vetted doubling of unit costs adopted in the 2015 GRC. One option would be to continue using amps-cutover to provide a consistent record of

[106] 18 RT 2685-2687, Roberts/ORA.

[107] ORA's first data request regarding 4 kV Cutovers was issued September 22, 2016 and asked for historic transformers cutover. See Ex. ORA-9 workpapers, Book 1, p.10.

[108] TURN recommends eliminating the 4 kV Elimination program.

work performed, and a goal of either 3,500 amps per year as adopted for TY 2012, or 2,500 amps per year as adopted for TY 2015. ORA recommends that a scope of 3,500 amps cutover per year be adopted, the same that was approved in the 2012 GRC. Should be directed to SCE provide additional discussion in its next GRC about this program in terms of scope and unit cost trends to inform a CPUC decision regarding the scope of this ongoing program. This will require that SCE collect data necessary to support a thorough analysis of the scope and unit cost of both 4 kV programs overtime using a consistent basis in terms of amps, transformers, or circuits.

Sub-Transmission Lines Plan

Regarding SCE's Sub-Transmission Lines Plan, a review of historical program expenditures shows a number of anomalies.[109] First, SCE's forecast for 2016-2020 has an average value of $78.729 million, but individual values vary significantly from this: nearly $40 million more in 2018 and 2019 but over $60 million lower in 2020. ORA expressed concern regarding SCE's ability to manage the work associated with this budget forecast, in part because SCE expressed a similar concern in its 4 kV Cutover program.[110] Given that program forecasts based on specific projects often change as project timing changes, and the difficulty in staffing a program that is forecast to increase to over $100 million in a single year (2019 to 2020), ORA recommends using the average value of SCE's forecast for 2016-2020: $78.729 million.

Second, in 2016, SCE expended less than half of its 2016 forecast for the program, which shows the difficulty in forecasting specific expenditures in a given year, and supports ORA's more restrained forecast.

Third, the average expenditures recorded for 2011-2016 were $25.329 million, or less than one-third of SCE's forecast average. This increase could be even greater because the recorded values shown are total expenditures, CPUC plus FERC, while the forecast is only for CPUC jurisdictional.[111] ORA's forecast does <u>not</u> attempt to adjust for this significant increase

[109] Ex. ORA-9A, p. 88 (and Ex. ORA-9, p. 85).

[110] SCE forecast of transformers to be cutover ranged from 2,258 in 2016 to 53 in 2020. SCE stated "Due to concerns on resource constraints, SCE applies levelization to forecast LG cutovers 2016-2020 to generate more reasonable work forecast." SCE used a 5-year average of 544 transformers ("Xfmr") for each year, 2016-2020. See SCE's response to data request ORA-SCE-002-TCR, Q. 18a, included Ex. ORA-9 workpapers, Book 1, p. 6.

[111] SCE did not provide historical data for project-based programs such as this one, as shown in Table IV-23, Ex. SCE-2, Vol. 3R, p. 96. ORA requested CPUC jurisdictional recorded costs in data request ORA-SCE-Verbal 36 Q.1, but SCE's response stated that only total costs could be provided. Based on the RO

compared to recorded expenditures. Adjustments to the RO Model were spread across all 81 projects with 100% CPUC forecasts, but not the two projects that had 100% FERC forecasts.[112]

When ORA entered its forecast into the RO Model, discrepancies were observed between SCE's forecast values for 2016 and 2018 for both the Sub-Transmission Lines Plan and the A-Bank Plan discussed in the next section.

ORA was not able to resolve these discrepancies so ORA used the Results of Operations Model values for both programs as the basis of its forecasts for both programs.

A-Bank Plan

ORA's only adjustment to SCE's A-Bank plan is to use recorded 2016 expenditures.[113] To apply the adjustment for 2016 recorded, ORA adjusted RO Model IDs 274, 289 and 338 for the CPUC portion, and RO Model ID 286 for the FERC portion.[114]

Sub-transmission VAR Plan

ORA's only adjustment to SCE's Sub-Transmission VAR plan is to use recorded 2016 expenditures.[115] To apply the adjustment for 2016 recorded, ORA adjusted RO Model ID 249.

System Improvement Programs

All System Improvement Programs are CPUC jurisdictional only.[116] With the exception of the Substation Equipment Replacement Program (SERP), ORA's only adjustment to SCE's System Improvement programs is to use recorded 2016 expenditures.[117]

SERP is an existing program for "work required to replace substation equipment identified to exceed their protection ratings to interrupt fault current."[118] SCE spent an average

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model, only 2 of the 83 projects classified as Sub-transmission Lines Plan have FERC expenditures forecast, but this is going forward, not historical.

[112] The two FERC only projects are included as RO Model IDs 423 and 424.

[113] Ex. ORA-9A, p. 89 (and Ex. ORA-9, p. 87).

[114] Ex. ORA-9-WP.

[115] In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit by which reactive power is expressed in an AC electric power system.

[116] Ex. ORA-9-WP, p. 134 citing SCE response to data request ORA-SCE-TCR-104, Q.3.

[117] Ex. ORA-9A, p. 90 (Ex. ORA-9, p. 88).

[118] Ex. SCE-2, Vol. 3R, p. 106.

of $8.821 million per year for 2013-2015, and in 2016 recorded expenditures dropped to $5.163 million.[119]

In the last GRC, the CPUC adopted a budget of $9.887 million a year, which was between SCE's forecast of "approximately $12 million" and ORA's forecast of $7.415 million.[120] In adopting the budget for this program, the CPUC stated "we agree with ORA that SCE has not demonstrated the need for the dramatic increase in replacements or the capacity to execute at this rate; however, we accept SCE's argument that some increase is warranted."[121] In the current case, SCE is increasing its request by more than three times the level of expenditures adopted in 2015, without providing adequate support for the need for such a large increase, nor SCE's capacity to do the work.

In a single paragraph, SCE provides all its justification for this increase of approximately $20 million per year, which consists of two limited arguments. First, SCE says "the evolving state of both the transmission and distribution systems has resulted in increased Short Circuit Duty levels across the SCE system."[122] SCE does not elaborate on what has "evolved" in the last three years to justify increases in annual program scope of 31% for 66 kV breakers and 114% for lower voltage breakers.[123] SCE states it performed a study in 2016 that resulted in a plan to replace more breakers, but it does not provide the study, the plan, or even a high level description in testimony or workpapers of what has changed since the 2015 rate case to justify this increase, beyond one sentence: "to help facilitate DER expansion and maintain safety and reliability of the electrical system as it evolves."[124]

In addition to the proposed increase in units per year, SCE's forecast includes a unit cost increase of 36% for 66 kV breakers, and 47% for lower voltage breakers.[125] SCE states it "analyzed historical cost data to develop unit costs" and cites to a workpaper in another volume of Exhibit SCE-2, but neither acknowledges the significant unit cost increase nor explains it.

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[119] 2013-2015 average from Figure IV-29, Ex. SCE-2, Vol. 3R, p.106.

[120] D.15-11-021, pp. 57-58.

[121] D.15-11-021, p. 57.

[122] Ex. SCE-2, Vol. 3R, p. 108.

[123] See Ex. ORA-9-WP. GRC, Ex. SCE-2, Vol. 3R, p. 107.

[124] Ex. SCE-2, Vol. 3R, p. 108.

[125] See Ex. ORA-9-WP.

The burden to justify rate increases rests with the utility, and SCE's request for this program does not meet that burden.

Based on the lack of justification for SCE's requested trebling of expenditures, ORA recommends that previously adopted funding levels be continued in terms of real dollars. In nominal dollars, ORA forecasts $10.212 million for 2017 and $10.456 for 2018 using ORA's escalation forecast. For 2016, ORA recommends using recorded expenditures of $5.163 million.[126]

Customer-Requested Projects

SCE forecasts two programs grouped together as Customer Requested Projects: the Generator Interconnection Program and Added Facilities Projects.[127]

SCE provided minimal description of each program. [128] ORA recommends using recorded 2016 expenditures, and has no adjustments for 2017 and 2018.[129]

Rights of Way

SCE's Rights of Way (ROW) program had minimal historical expenditures, but starting in 2016, cost approximately $500,000 per year.[130] ORA does not propose adjustments to SCE's forecast, except using recorded 2016 expenditures.[131]

In-Service Projects

SCE's testimony mentions In-Service Projects in a footnote: "the following capital expenditures for projects with operating dates prior to 2016 are not included in the table above: $16.9 M [million] in 2016, $6.4M in 2017, and $2.8M in 2018."[132] This applies to the total

[126] Exs. ORA-9A, (and Ex. ORA-9) p. 64, Table 9-3.

[127] Added facility projects are all CPUC jurisdictional, so the 2016 adjustment to recorded was made by reducing two large projects, RO Model ID 39 and 58. The Generator Interconnection Program includes two projects with FERC expenditures. The CPUC portion of the 2016 adjustment was made to RO Model ID numbers 76, 77, and 82-86. The FERC adjustment was made to RO Model ID number 536.

[128] Ex. SCE-2, Vol. 3R, p. 111.

[129] Ex. ORA-9A, p. 92 (and Ex. ORA-9) p. 90.

[130] Ex. SCE-2, Vol. 3R, pp. 113-114.

[131] Ex. ORA-9A, p. 92 (and Ex. ORA-9) p. 90.

[132] Ex. SCE-2, Vol. 3R, p. 50, footnote 81.

expenditures, FERC plus CPUC, and while the RO model includes 24 In-Service projects, all but $61,000 in 2016 are FERC costs, so these projects have a minimal impact on CPUC jurisdictional rates.[133] SCE's 2016 recorded cost were recorded as negative, and adjusting SCE's 2016 forecast to this recorded value is the only adjustment ORA made.[134]

Distribution Deferral Pilot Projects

SCE proposes a pilot project to a) perform eight projects to evaluate the potential to defer eight load growth projects and b) test whether DER can impact transformer life.[135] SCE states that a memorandum account has been proposed to track project costs "net of actual amounts expended on the deferred projects,"[136] but provides no estimate of the costs to run the DER solicitations and other costs associated with running the pilot. In general, the pilot is poorly defined compared to the demonstration projects mandated and approved in the DRP proceeding, which were subjected to cost caps in D.17-02-007.[137] SCE also does not discuss the cost of the 74 circuits that are included in the Distribution Automation program that are attributed to the deferral projects.[138]

While ORA sees the potential value in this pilot program, ORA does not agree with the approach taken by SCE. As discussed in section 4.11.1 of this brief in connection with Energy Storage Pilots, SCE should not be proposing pilot projects in this GRC. In addition, while SCE notes that one of the proposed deferral projects is also included in DRP Demo C,[139] it does not explain what incremental value this pilot will provide relative to the Demo C project that has been subjected to a stakeholder vetting process, and approved with a cost cap in D. 17-02-007. The DRP proceeding explicitly allowed utilities to propose demonstration programs beyond

[133] See Ex. ORA-9-WP.

[134] Ex. ORA-9A, p. 92 (and Ex. ORA-9) p. 90.

[135] Ex. SCE-2, Vol. 3R, p. 49.

[136] Ex. SCE-2, Vol. 3R, p. 49.

[137] Ex. ORA-9A, p. 93 (and Ex. ORA-9), p. 91, footnote 290 citing SCE Workpapers supporting Ex. SCE-2, Vol. 3R, Book A, pp. 8-16.

[138] Ex. ORA-9A, p. 93, (Ex. ORA-9), p. 91.

[139] Ex. SCE-2, Vol. 3R, p. 49, footnote 76.

those required by the February 6, 2015 guidance document.[140] While other parties filed alternative proposals, SCE did not.[141] For the reasons above, ORA does not support this pilot.

4.4 T & D – Distribution Maintenance and Inspection

4.4.1 Capital

- **Distribution Construction and Maintenance Programs**

ORA does not oppose SCE's other capital expenditure requests for distribution construction and maintenance programs, but does recommend the Commission decrease its Prefabrication 2016-2018 forecast by $199,000.[142]

Prefabrication is a process of assembling needed parts, equipment and material in the service center yard to be ready for transport to the needed location rather than performing such work at the worksite. SCE justifies this program with:

> Prefabrication activities provide distribution crews with the materials needed for daily construction or maintenance work. Rather than having each crew spend time at the warehouse every day trying to gather the equipment and parts needed to execute the work, prefabrication streamlines this for them. […] The immediate and long-term impact of eliminating prefabrication would be a reduction in construction and maintenance work completed as qualified electrical workers would perform the prefabrication activities.[143]

Edison bases its forecast on the declining level of expenditures for prefabrication. SCE explains that since 2012, the Company has "been able to streamline the material and staging activities in our districts, which is reflected in the declining level of expenditures for Prefabrication. This decline occurred even while our overall capital expenditures increased significantly."[144] Figure I-5 of SCE's testimony shows a graph along with the actual recorded and forecast costs from 2011-2020 demonstrating a decline in prefabrication costs from 2012 to

[140] Ex. ORA-9A, p. 93 (and Ex. ORA-9), p. 91.

[141] SDG&E originally proposed a "Demo Project F" in its July 1, 2015 DRP, but retracted the request in its final proposal filed June 17, 2016 in R.14-08-013. Proposals for other demonstration projects were filed by the Center for Sustainable Energy (CSE), Bloom Energy, and Community Environmental Council on June 17, 2016 in R.14-08-013. These proposals were not adopted. See D.17-02-007, Ordering Paragraphs 18-20, p. 39.

[142] EX.ORA-11, p. 1-6.

[143] Ex. SCE-02, Vol. 05, p. 24, lns. 14-20.

[144] Ex. SCE-02, Vol. 05, p. 25, lns. 4-7.

2015. The table below summarizes the recorded constant 2015$ costs of prefabrication as well as Edison's forecast for 2016-2020.[145]

Prefabrication – Recorded 2011-2015*/Forecast 2016-2018*

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Constant 2015$	18,828	20,432	16,153	13,093	9,715	*10,492*	*10,194*	*9,857*

Source: Ex. SCE-2, Vol. 05, p. 25, Figure I-5.

In forecasting 2016-2018 prefabrication costs, SCE considered declining costs and "consistent with Commission guidance, we forecast future expenditures to be the same as 2015 recorded for total prefab costs, which are split between this activity and Pole Loading Program related prefabrication."[146]

ORA finds SCE's testimony to be inconsistent with the constant 2015$ expenses presented in SCE's Figure I-5 since the constant 2015$ expenses continued to increase after 2015 and issued a data request seeking a clarification. In response to ORA's data request, Edison acknowledged the error, agreed with ORA that its forecast should have shown $9,715,000 for 2016-2020 and stated it would serve Errata to correct this error.[147]

In a follow-up data request, ORA requested SCE to update Figure I-5 on p. 25 of Ex. SCE-02, Vol. 05 and to include updated nominal$ and constant 2015$ numbers. The updated Figure I-5 is shown below as Figure 11-1.

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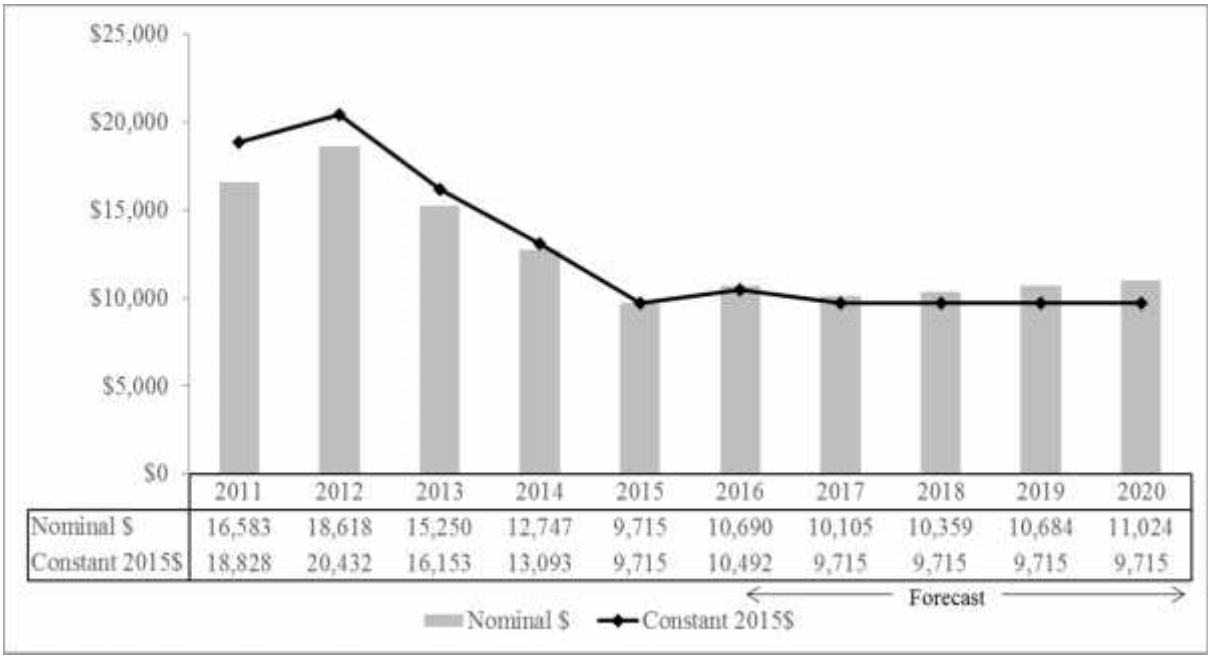
Figure 11-1
Updated Figure I-5 – SCE-02, Vol. 05 - Prefabrication[148]

[145] Ex. ORA-11, pp. 6-7.

[146] Ex. SCE-02, Vol. 05, p. 25, lns. 7-9.

[147] SCE response to data request ORA-SCE-145-YNL, Q.6.a.

[148] ORA-SCE-201-YNL, Q.2, Att-Updated Table-SCE-02 Vol. 05 - Prefabrication.



ORA notes that both nominal and constant 2015$ costs in Figure 11-1 for 2016 are forecasts and not actual recorded expenses. In response to data request ORA-SCE-108-TXB, Q.02 Supplemental Revision, SCE provided recorded adjusted capital expenditures for 2016. ORA uses Edison's 2016 recorded costs instead of SCE's 2016 forecast; the table below summarizes ORA's recommendations and SCE's initial request in the testimony.[149]

Prefabrication – ORA Recommendation vs. SCE Proposal

	2016	2017	2018
ORA Recommendation	$11,141	$10,105	$10,359
SCE Request	10,690	10,603	10,511
Net Difference	451	(498)	(152)

Thus, ORA recommends the Commission adjust SCE's proposed forecast for 2016-2018 by $199,000.

- **Substation Construction and Maintenance Programs**

Since 2014, Edison has been incurring and recording costs for substation physical security and here SCE requests additional money to fund its "several substation physical security programs in place to prevent theft, address compliance requirements, and protect SCE's critical

[149] Ex.ORA-11, p. 8.

assets."[150] The table below summarizes SCE's request and breaks it down by various programs.[151]

Table[152]
Substation Physical Security Enhancements Programs
Recorded 2014-2015 / Forecast 2016-2020 (Nominal $000)

	Number of Substations	2014	2015	2016	2017	2018	2019	2020
Copper Theft	8/year from 2016 and on	$-	$3,330	$8,151	$8,321	$8,530	$8,798	$9,077
Tier 1: Pre-CIP-014 & CIP-014	7	$11,844	$14,408	$14,190	$42,550	$9,052	$-	$-
Tier 2-4	29	$-	$-	$-	$746	$8,059	$13,606	$14,800
	Total	**$11,844**	**$17,738**	**$22,341**	**$51,618**	**$25,640**	**$22,404**	**$23,877**

Regarding copper theft, Edison explains that "SCE has experienced substations being vandalized and looted for copper over the past few years. From 2013-2014 there were, on average, over 13 break-ins to SCE substations per month that resulted in losses due to copper theft, customer outages, and/or serious injury to thieves."[153] Furthermore, "copper theft presents a significant safety risk to SCE employees and contractors" and "[a]ffected customers experience an average of 11 hours of outage each time power is shut off either due to the impact of the theft itself, or due to the repair work required to replace copper parts."[154] According to SCE:

> Because of these safety and reliability risks, SCE has developed a program to reduce copper theft at its substations. We have identified which facilities require physical security enhancements to minimize the possibility of future copper thefts based on factors such as safety (customer and employee) risks and the history of theft at stations. The prioritized substations receive high security fencing and improved lighting to deter theft and reduce the risk of injuries or customer outages. Initial results of this program are proving to be highly effective. Substations given these enhancements have seen a reduction in the number of thefts.[155]

[150] Ex. SCE-02, Vol. 06, p. 42, lns. 10-11.

[151] EX. ORA-11, p. 9.

[152] Ex. SCE-02, Vol. 06, p. 46, Table I-17.

[153] Ex. SCE-02, Vol. 06, p. 42, lns. 13-15.

[154] Ex. SCE-02, Vol. 06, p. 42, lns. 18-23.

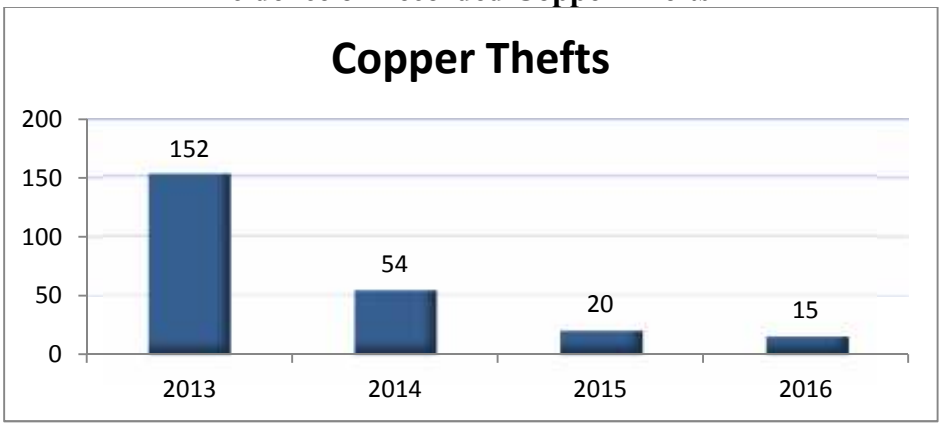
[155] Ex. SCE-02, Vol. 06, pp. 42-43.

ORA reviewed SCE's testimony, workpapers and issued numerous data requests. After considering all of the material, ORA developed independent forecasts for 2017 and 2018 because: 1) copper theft has decreased; 2) there are many non-copper theft incidents; and 3) 30% of copper theft incidents in 2013 only occurred at 6 substations.[156]

Copper Theft Has Decreased

SCE forecast $8.151, $8.321, and $8.53 million in copper theft program expenses for 2016, 2017 and 2018, respectively. SCE recorded approximately $10 million in costs for 2016.[157] While ORA is not opposed to Edison recovering its 2016 costs, ORA is not convinced such large expenses will continue in 2017 and 2018 given that copper theft has drastically decreased. Edison experienced on average thirteen break-ins to its substations per month[158] in 2013, but the actual number of total copper thefts decreased to 20 in 2015 and 15 in 2016. The figure below provides a visual illustration of the decline in copper thefts:

Incidence of Recorded Copper Thefts[159]



In response to ORA's data request seeking clarification on why there has been such a decrease in total annual metal theft record, Edison explains:

> SCE cannot provide full analysis and exact predictions on metal theft behavior, but traditional drivers include the market price of the materials, effectiveness of theft deterring installations, heightened awareness of electrical grid security and associated safety risks, public education and local law enforcement activities. In

[156] Ex. ORA-11, p. 10-15.

[157] ORA-SCE-Verbal-040, SCE-2 Vol. 5, 6, 7.

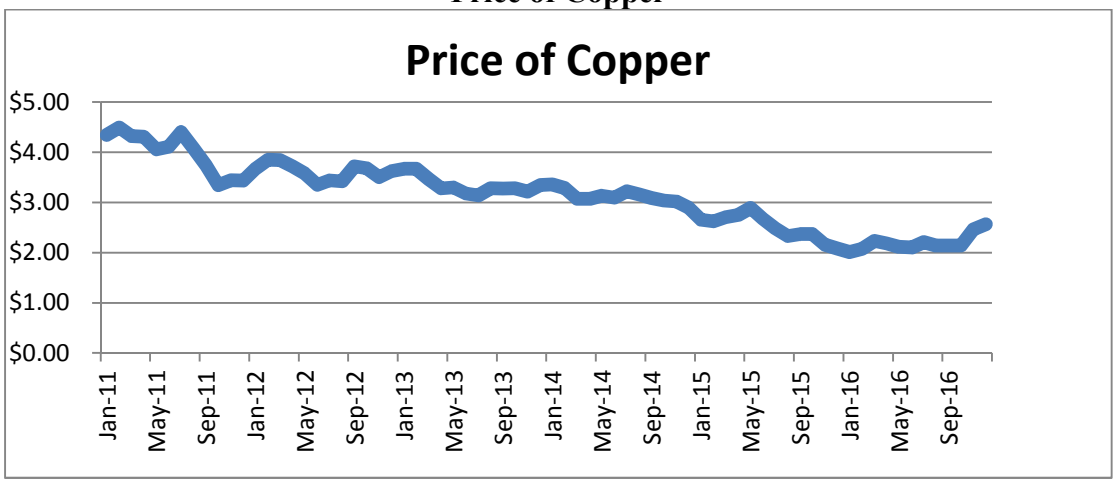
[158] Ex. SCE-02, Vol. 06, p. 42, ln. 14.

[159] SCE response to data request ORA-SCE-154-YNL, Q.16_metal theft update.

addition, copper is the metal most often stolen from our substations. From Jan 2011 to Jan 2016, the price of copper dropped by 53%. Combined with our increased security measures, this led to a significant decrease in metal theft. […] No substation receiving metal theft security enhancements has had a theft of metal, equipment vandalized, or an outage resulting from theft or vandalism.[160]

The figure below shows the decline in the price of copper over time.

Figure[161]
Price of Copper



Non-Copper Theft Security Incidents

Aside from copper theft incidents, Edison also experiences non-copper theft security breaches such as theft, trespassing, suspicious activities and vandalism. The table below and the corresponding figure details these incidents over the 2012-2016 period.[162]

[160] SCE response to data request ORA-SCE-207-YNL, Q.2.c.

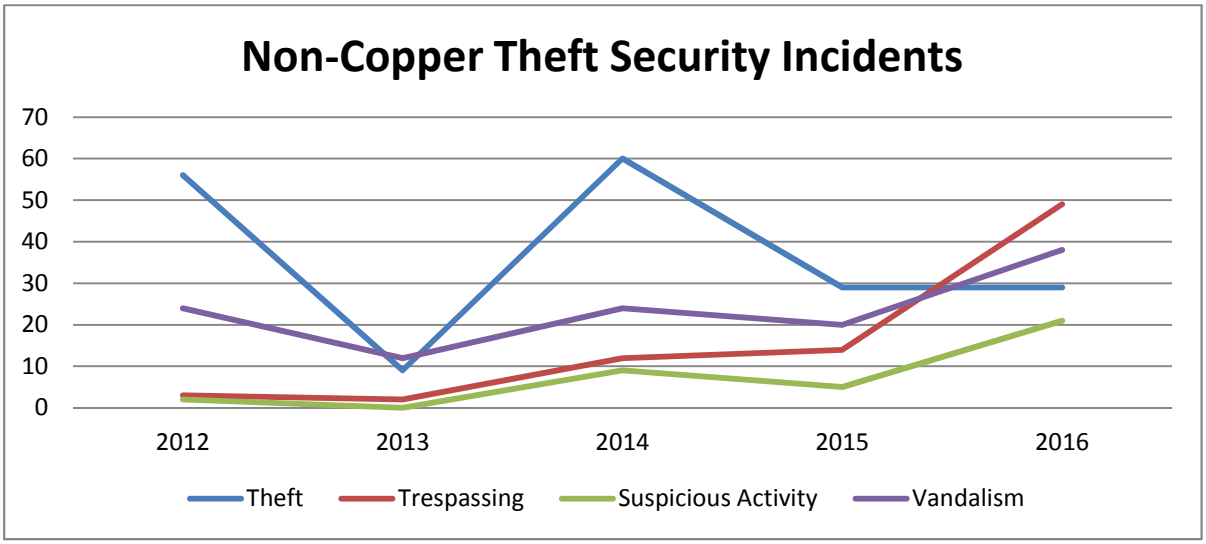
[161] ORA-SCE-154_YNL, Q.10_copper price.

[162] EX. ORA-11, p. 12.

Non-Copper Theft Security Incidents[163]

	2012	2013	2014	2015	2016	TOTAL
Theft	56	9	60	29	29	183
Trespassing	3	2	12	14	49	80
Suspicious Activity	2	0	9	5	21	37
Vandalism	24	12	24	20	38	118

Non-Copper Theft Security Incidents



ORA considers theft and vandalism as the most serious of the four types of incidents with theft accounting for 43.8% of the total incidents over 2012-2016 and vandalism at 28.2%. ORA requested Edison to provide additional information on the dollar value of each theft incident and aggregate the theft incidents into quartiles on the value of property stolen and to indicate the total frequency of incidents per quartile. SCE responded, "SCE tracks all thefts that occur on SCE property such as laptops, vehicles, cell phones, tools/equipment, and metals. These incidents are documented as investigation reports and can contain dollar value estimates, if known. However, most of the investigation reports currenty do not include dollar value."[164]

[163] SCE response to data request ORA-SCE-154-YNL, Q.16.c.

[164] SCE response to data request ORA-SCE-207-YNL, Q.5.b.

Similarly, ORA requested additional information regarding vandalism; SCE responded "[t]he types of vandalism SCE tracks include incidents such as graffiti, fence cuts, vandalism to pole structures, and electrical equipment. […] SCE documents security incidents by means of individual investigation reports, which may record cost estimates for the value of property/equipment damange when available. However, as mentioned in part b of this question, most investigation reports on file do not contain dollar values. SCE does not track vandalism incidents by the value of the property vandalized."[165]

Given the lack of information regarding the types of theft and vandalism incidents and the damage the Company incurred as a result of them, ORA disagrees with Edison's copper-theft forecasts based on non-copper theft security incidents.[166]

In 2013, over 30% of Copper Theft Incidents Occurred In Only Six Substations

In response to its data request, ORA determined that in 2013 out of a total of 152 copper theft incidents, 48 thefts occurred at just six substations. The table below summarizes this information along with Edison's security enhancement expenditures:

High Frequency Copper Thefts by Substation In 2013[167]

Substation	2013 Total	Zip Code	City	Security Costs in 2015	Security Costs in 2016
Substation 15	7	92402	San Bernardino		
Substation 30	5	92404	San Bernardino	$68,847.15	$1,954.32
Substation 55	13	92346	Highland	$(27,284.13)	
Substation 134	8	92405	San Bernardino		
Substation 141	6	92401	San Bernardino	$94,414.53	$581.26
Substation 150	9	92410	San Bernardino		

The average cost for substation fencing/lighting upgrades is approximately $1 million per site.[168] Therefore, based on SCE's forecasts for 2017 and 2018 for the copper theft substation physical security enhancement programs, SCE will be able to upgrade security at 16-17 sites. Given that only six SCE substations experienced four or more copper theft incidents between

[165] SCE response to data request ORA-SCE-207-YNL, Q.5.c.

[166] Ex. ORA-11, p. 14.

[167] SCE response to data request ORA-SCE-207-YNL, metal theft update revised for ORA-207 Excel file.

[168] SCE response to data request ORA-SCE-207-YNL, Q.2.d.

2013-2016, including the 6 referenced above, that these six substations - accounted for over 30% of all copper theft incidents in 2013 (eleven substations accounted for 44.5% of all incidents) and that there has been a drastic decrease in copper theft (as discussed above), ORA recommends the Commission not accept SCE's request for 2017 and 2018.[169]

Since ORA uses Edison's 2016 recorded costs in place of the SCE's 2016 forecast, the following table below summarizes ORA's recommendations and SCE's request. ORA developed forecasts for 2017 and 2018 to ensure that Edison will have enough funds to install substation fencing and lighting upgrades at the ten[170] substations that experienced substantial thefts in 2013.[171]

Copper Theft Substation Physical Security Enhancement Program – ORA Recommendation vs. SCE Request (in $000)

	2016	**2017**	**2018**
ORA Recommendation (Nominal $)	$10,002	$5,000	$5,000
SCE Proposal (Nominal $)	8,151	8,321	8,530
Net Difference	1,851	(3,321)	(3,530)

ORA recommends a forecast for copper theft substation physical security enhancement program of $5.0 million for 2017 and 2018.[172]

The Commission Should Deny SCE's Subtransmission Relay Upgrade Request

SCE requests funding for the Subtransmission Relay Upgrade Program (SRUP) which "will replace those 66kV and 115 kV line protection relay devices identified as potentially unreliable under the condition of load encroachment caused by additional Distributed Energy Resources (DER) generation."[173] The table below summarizes SCE's request.

[169] Id.

[170] ORA notes that SCE already spent $783,948 at one of the eleven substations mentioned.

[171] Id.

[172] Ex. ORA-11, p. 15.

[173] Ex. SCE-02, Vol. 06, p. 32, lns. 9-11.

Table[174]
Subtransmission Relay Upgrade: WBS Element CET-ET-GM-SA
(CPUC-Jurisdictional – Constant 2015 and Nominal $000)

	2016	2017	2018
Nominal $	$0	$0	$41,589
Constant 2015$	$0	$0	$39,004

ORA reviewed SCE's request for funding Grid Modernization in Exhibit ORA-09, Section 3.C.8. ORA does not support ratepayer funding for a comprehensive Grid Modernization plan until the Distributed Resource Plan proceeding has reached key decisions and results from related research, development, and demonstration projects are available.

ORA reiterates its conclusion regarding Grid Modernization as it pertains to Subtransmission Relay Upgrade Program. Since ORA uses SCE's 2016 recorded costs in place of SCE's 2016 forecast, the table below summarizes ORA's recommendations and SCE's request.[175]

Subtransmission Relay Upgrade -- ORA Recommendation vs. SCE Proposal (in $000)

	2016	2017	2018
ORA Recommendation (Nominal $)	$311	$0	$0
SCE Proposal (Nominal $)	0	0	$41,589
Net Difference	311	0	(41,589)

ORA recommends no funding of SCE's subtransmission relay upgrade program for 2018.

- **Transmission Construction And Maintenance Programs**

ORA recommends the Commission adjust $616,000 in 2016 and $519,600 in 2017 for Transmission tools and work equipment activities.

Edison presents the following in requesting funding for its transmission tools and work equipment:

> Transmission Tools and Work Equipment include the costs for acquiring and retiring portable tools and work equipment that cost more than $1,000. Portable tools are moderately priced and have relatively long lives. Examples include electric, pneumatic, hydraulic power tools, electric generators, cable pulling

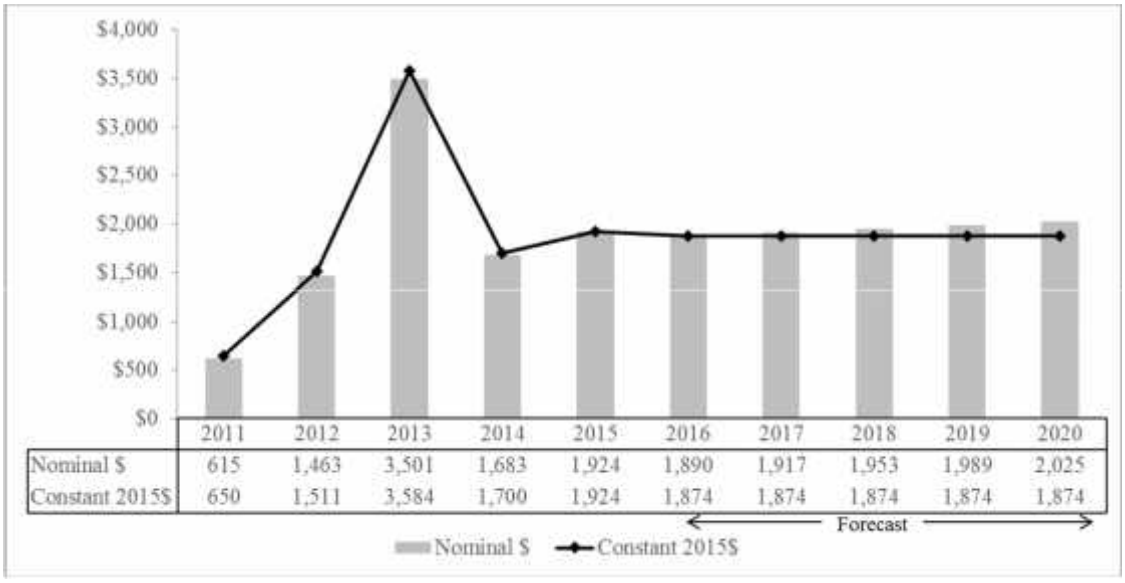
[174] Ex. SCE-02, Vol. 06, p. 36, Figure I-5.

[175] Ex. ORA-11, p. 16.

equipment, water pumping equipment, gas monitors, air compressors, and compression tools for making high voltage electrical connections. Replacement of tools or equipment to increase efficiency or due to technological changes is also included.[176]

Edison bases its forecast on the use of a five-year average for the 2016-2018 forecasts citing unpredictability in equipment failures. Furthermore, in support of using the five-year average, SCE explains that transmission tools and work equipment costs vary by year depending on the number of tool and equipment replacements required due to retirements or new requirements.[177] The figure below, reproduced from SCE's testimony, summarizes the recorded 2011-2015 costs for transmission tools and work equipment as well as Edison's 2016-2020 forecast costs.[178]

Figure[179]
Transmission Tools and Work Equipment – Recorded 2011-2015/Forecast 2016-2020
(CPUC-Jurisdictional – Constant 2015 and Nominal $000)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nominal $	615	1,463	3,501	1,683	1,924	1,890	1,917	1,953	1,989	2,025
Constant 2015$	650	1,511	3,584	1,700	1,924	1,874	1,874	1,874	1,874	1,874

ORA notes that SCE's 2016 nominal and constant 2015$ costs in Figure 11-5 are forecasts and not actual recorded expenses. In response to data request ORA-SCE-108-TXB,

[176] Ex. SCE-02, Vol. 07, p. 33, lns. 9-12 and p. 34, lns. 1-2.

[177] Ex. SCE-02, Vol. 07, p. 34, lns. 4-8.

[178] Ex. ORA-11, p. 17.

[179] Ex. SCE-02, Vol. 07, p. 34, Figure IV-11.

Q.02 Supplemental Revision, SCE provided recorded adjusted capital expenditures for 2016. The response showed that while Edison forecast spending $1.890 million in 2016, the Company actually recorded $1.274 million in expenses (a $616,000 reduction).[180]

As the figure above shows, the costs in 2013 more than doubled compared to 2012. ORA issued a data request asking for an explanation and supporting documentation behind the substantial increase in 2013 recorded costs for transmission tools and work equipment. In its response, SCE named three factors:[181]

1. Increasing workload and the need to replace old, worn, or broken tools.
2. The Transmission Planned Capital Maintenance (TPCM) program had an increased workload starting in 2013 due to implementation of a new planned capital maintenance approach. Additionally, in 2014 the expense for TPCM was even higher due to targeting underground cable. (SCE referred ORA to Figure II-3 on page 11 of Ex. SCE-2, Vol. 7 as well as the supporting narrative on pages 11-12 for additional details regarding the costs increases experienced in the TPCM program in 2013-2014.)
3. In 2013, SCE was in the process of modernizing inspection and execution efforts by bringing in new or updated technology.

ORA reviewed SCE's testimony (Ex. SCE-02, Vol. 7) on pages 11-12, including Figure II-3, which is presented below:

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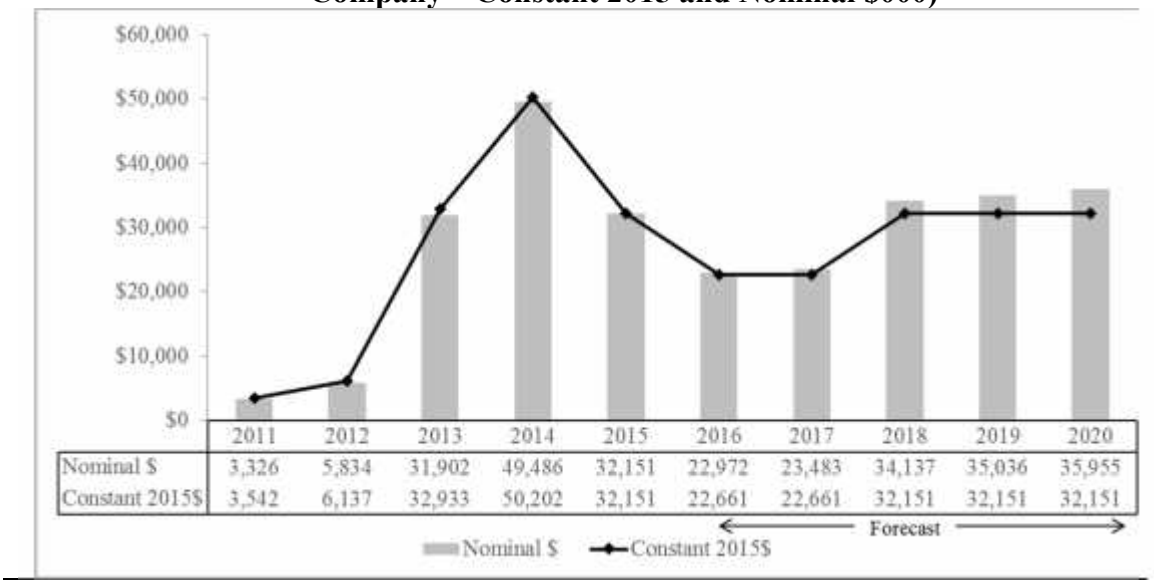
[180] Ex. ORA-11, p. 18.

[181] SCE response to data request ORA-SCE-155-YNL, Q.12.

Ex. SCE-2, Vol. 7, Figure II-3, Transmission Planned Capital Maintenance (Total Company – Constant 2015 and Nominal $000)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nominal $	3,326	5,834	31,902	49,486	32,151	22,972	23,483	34,137	35,036	35,955
Constant 2015$	3,542	6,137	32,933	50,202	32,151	22,661	22,661	32,151	32,151	32,151

As observed in Figure II-3 above, costs began to decrease substantially after 2014. Edison stated:

> Costs decreased in 2015 to levels closer to 2013 when the program first started. While 2015 is the most representative of what the average annual program expenditures will be during this GRC cycle, we expect to incur resource constraints that will inhibit our ability to support this level of planned capital maintenance in 2016 and 2017. For example, SCE must r amp up its work in its Transmission Line Rating Remediation (TLRR) program in 2016 and 2017, which will require additional resources to be reassigned from existing work to support the program in the short run until we can build up our resource pool. As such, SCE is proposing an adjustment to reduce its planned capital maintenance forecast in 2016 and 2017, to 70% of the last year (2015) recorded costs. Beginning in 2018, SCE expects our resource pool to be built up to perform maintenance at the 2015 level and is proposing to use 2015 recorded capital expenditures as the basis of the 2018-2020 forecast.[182]

ORA issued a data request inquiring what Edison meant by "we expect to incur resource constraints." SCE responded that "[b]ecause the TLRR program will be ramping up in 2016 and 2017, this will limit the number of planning personnel available for the planned capital maintenance work" and that "this resource requires several years of training to adequately perform the job." Finally, "[b]ecause planners are highly skilled resources, there are a limited a

[182] Ex. SCE-02, Vol. 07, p. 12, lns. 8-17.

number of people who are qualified to perform this work. For this reason and because SCE has a limited number of planners available, we expect to incur resource constraints to support 2016 and 2017 planned capital maintenance work at levels similar to 2015."[183]

Given that there appears to be a correlation between increased expenditures on transmission tools and work equipment and the increased workload starting in 2013 in the TPCM and Edison citing TPCM workload as one of the reasons for increased expenditures on tools and equipment, ORA proposes capping the forecast costs in a similar way SCE proposed for transmission planned capital maintenance projects for 2016 and 2017. Since ORA uses Edison's 2016 recorded costs in place of SCE's 2016 forecast, the table below summarizes ORA's recommendations and SCE's request.

Transmission Tools and Work Equipment – ORA Recommendation vs. SCE Proposal, ($000)

	2016	2017	2018
ORA Recommendation (Nominal $)	$1,274	$1,397[184]	$1,953
SCE Proposal (Nominal $)	1,890	1,917	1,953
Net Difference	(616)	(529)	0

ORA recommends the Commission adjust $616,000 in 2016, which is based on SCE's actual recorded costs and adjust $519,600 in 2017 for transmission tools and work equipment activities.[185]

4.5 Distribution Construction and Maintenance

4.5.1 O&M

SCE's Distribution Construction and Maintenance organization is responsible for patrolling, locating and repairing problems on its distribution system. The activities of the

[183] SCE response to data request ORA-SCE-155-YNL, Q.4.b.

[184] 1,397.4 = 1,924 * 70% *1.013 * 1.025. ORA assumes annual inflation rate of 1.3% for 2016 and 2.5% for 2017 based on IHS Economics – U.S. Economic Outlook.

[185] EX. ORA-11, pp. 19-20.

organization include maintaining, inspecting and replacing underground structures and streetlights and responding to power outage emergencies.[186]

In its Application, SCE combined the forecast expenses from seven FERC sub-accounts to calculate its forecast of $70.490 million for its Distribution Construction and Maintenance expenses. SCE developed its forecast by using 2015 recorded adjusted expenses and historical averages for proposed test year projects and activities. The corresponding ORA estimate for SCE's Distribution Construction and Maintenance expenses is $65.946 million. ORA's estimate is $4.544 million less than SCE's forecast.[187]

ORA does not oppose SCE's TY forecast for FERC sub-accounts: 583.170 – Patrolling For, Locating, and Repairing Trouble on the Distribution System ($32.237 million), 586.140 – Setting, Removing, and Relocation Customer Meters ($10.270 million), 588.140 – Stand By time, Distribution Business Line Construction Support, Underground Structure Shoring and Repairs and Information Technology/Corporate Real Estate Chargebacks ($9.093 million) or 588.170 – Outage Data Management and Circuit Mapping ($1.989 million).

ORA disagrees with SCE's TY forecasts for Streetlight Operations and Maintenance, Service Guarantee Credits, and Distribution Storm Expenses for the reasons discussed below.[188]

- **FERC Sub-Account 585.170**

Streetlight Operations and Maintenance

SCE forecasts $6.936 million for FERC sub-account 585.170 (Labor of $3.674 million and Non-Labor of $3.262 million) for its Streetlight Operations and Maintenance expenses.[189] SCE used its 2015 recorded adjusted expenses as the basis for its TY 2018 forecast.

ORA forecasts $4.543 million using SCE's street light model[190] as a basis for its estimate. ORA's estimate is $2.393 million less than SCE's forecast.[191]

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[186] Ex. SCE-2, Vol. 5, p. 1.

[187] Ex. ORA-7, p. 11.

[188] Ex. ORA-7, p. 12.

[189] Ex. SCE-2, Vol. 5, p. 58.

[190] ORA's estimate of $4.543 million is taken from SCE's streetlight model provided in SCE's response to data request ORA-SCE-076-TLG, Q.1-f-1. ORA's estimate is comparable to SCE's 2016 recorded adjusted expenses for Accounts 585.170 and 596.170 of $4.850 million for streetlight operations and maintenance. SCE provided 2016 recorded adjusted expenses in data request ORA-SCE-108-TXB, Q.1. (See Ex. ORA-7, p. 13, footnote 24.)

To justify its use of 2015 recorded expenses for its estimate, SCE says that, "[t]he last recorded year reflects the cost reductions we achieved through our restructuring of the Street Lighting organization and decrease in maintenance activities attributable to past efforts from our proactive replacement program."[192]

SCE's forecast does not adequately account for future activities[193] that will reduce SCE's maintenance expenses still further in the TY.[194] For instance, SCE's estimate does not take into account the installation/conversion of 300,000 Light Emitting Diode (LED) technology[195] streetlights, which are more energy efficient and require less maintenance. As even SCE notes, "[a]s LED technology has matured, the cost of LED luminaries has declined and the expected useful life now exceeds that of HPSV street lighting technology."[196]

Nor does SCE's forecast take into account the sale of approximately 110,000 street lamps to cities,[197] and the cost reduction associated with reduced call volume from customer-related and patrol-identified streetlight burnout issues.[198]

SCE's recorded adjusted expenses declined by $2.108 million between 2013 and 2015, from $9.044 million in 2013 to $6.936 million in 2015. The decline in expenses was due to "fewer repair activities and an organizational change."[199]

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[191] Ex. ORA-7, p. 13.

[192] Ex. SCE-2, Vol. 5, p. 46.

[193] SCE's line items for ongoing and routine expenses related to streetlight Administration and Billing and its streetlight light maintenance related to its Design Construct and Maintain activities have both declined between 2014 and 2015 and should continue to decline in the TY. SCE's streetlight billing activities are not new and have costs embedded in rates, and incremental funding of $1.434 million ($4.302 million over three years) that is in addition to 2015 recorded expenses for this activity of $0.928 million in the TY is not required. SCE response to data request ORA-SCE-076-TLG, Q.1-f-1 and Ex. SCE-2, Vol. 5, Workpapers, p. 138. (See Ex. ORA-7, p. 13, footnote 27.)

[194] Ex. ORA-7, p. 13.

[195] SCE owns approximately 680,000 streetlights. Of that number, SCE plans to convert 300,000 to LED lights by the end of 2020. (Ex. SCE-2, Vol. 5, pp. 39 and 40 and SCE's response to data request ORA-SCE-076-TLG, Q.1-c (Ex. ORA-7-WP, p. 7-8.)

[196] Ex. SCE-2, Vol. 5, p. 40.

[197] Ex. SCE-2, Vol. 5, p. 41.

[198] SCE states it "anticipates the volume of customer-related and patrol-identified issues will decline as increasing quantities of LEDs replace non-LED lights." SCE response to data request ORA-SCE-076-TLG, Q.1-f-6 (Ex. ORA-7-WP, p. 7-15 – 7-16).

[199] Ex. SCE-2, Vol. 5, p. 46.

In SCE's 2015 GRC, SCE was authorized $9.245 million for Account 585.170. SCE's 2015 recorded adjusted expenses were $6.936 million, or $2.309 million less than authorized. A reduction in maintenance costs due to the installation of LEDs is warranted.[200]

ORA recommends a forecast of $4.543 million for the test year for this account.[201]

Service Guarantee Credits

SCE requests that a baseline of service guarantee credits of $577,000[202] associated with its two Transmission and Distribution-driven guarantees for the Test Year be changed from being 100% shareholder-funded[203] to requiring that customers fund the credits. These are credits that are to be paid to customers who have been inconvenienced by SCE's failure to meet service commitments. ORA recommends that SCE's request be denied.[204]

SCE says it "concurs with the notion that we should compensate our customers for the inconvenience that occur when the Company does not meet the standards set by Service Guarantees."[205] Nonetheless, SCE "requests that the Commission reverse this long-standing policy and recognize that a base level of credits should be included in SCE's costs as reasonable."[206]

The two T&D-driven service guarantees are Service Guarantee #2 – Service Restoration (within 24 hours) and Service Guarantee #3 – Notification of Planned Outage.[207] SCE pays rebates, a $30 credit, to customers for each occurrence when SCE fails to meet these Service Guarantees.[208]

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[200] D.15-11-021, p. 150. SCE provided its 2015 GRC authorized amount of $9.245 million in response to data request ORA-SCE-Verbal-006, Q.1 (Ex. ORA-7-WP, p. 7-9 – 7-14.)

[201] Ex. ORA-7, p. 14.

[202] Ex. SCE-2, Vol. 5, p. 18.

[203] Ex. SCE-2, Vol. 5, p. 15.

[204] Ex. ORA-7, p. 15.

[205] Ex. SCE-2, Vol. 5, p. 18.

[206] Ex. SCE-2, Vol. 5, p. 18.

[207] Ex. SCE-2, Vol. 5, p. 16.

[208] Ex. SCE-2, Vol. 5, p. 15.

The Service Guarantee Credits, which the Commission has found should be paid by SCE shareholders, have been in place since 2004.[209] Ever since then, however, SCE has been trying to shift the costs to its customers to make them pay for SCE's failures to live up to service commitments. The Commission has refused to do so. The Commission should reaffirm this policy.

In D.06-05-016, which resolved SCE's Test Year 2006 GRC, the Commission continued the requirement that SCE, not its customers, fund SCE's service guarantee credit program. In D.06-05-016 the Commission stated:[210]

> Regarding the payments to customers, these are payments that result from the company not meeting its commitments to individual customers. If the company is unable to meet its commitments, the shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer.

In the Commission's decision on SCE's 2012 GRC, the Commission stated:[211]

> We agree with DRA that SCE's proposal to have ratepayers fund baseline service guarantee credits should be denied. The Commission has adopted this view in the two previous Edison GRCs and the utility has not articulated persuasive arguments for reversing this longstanding policy decision.

Again, in deciding SCE's Test Year 2015 GRC, the Commission stated:[212]

> ORA cites prior GRC decisions rejecting ratepayer funding for guarantee payouts and recommends that we continue that policy. As we found in D. 12-11-051, we agree with ORA that SCE has not presented a persuasive argument for ratepayer funding of service guarantees. Therefore, we reject SCE's proposal.

SCE still has not articulated a persuasive argument for reversing this long standing policy. Nothing has changed since the Commission first stated its policy that: "[I]f the company

[209] D.04-07-022.

[210] D.06-05-016, p. 122.

[211] D.12-11-051, p. 228.

[212] D.15-11-021, p. 151.

is unable to meet its commitments, the shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer."[213]

Distribution Storm Expenses

SCE forecasts $9.388 million for FERC sub-account 598.170 (Labor of $4.764 million and Non-Labor of $4.624 million) for its Distribution Storm expenses.[214] SCE's forecast of $9.388 million, based on a five year average (2011-2015) is an increase of $1.907 million, or 25.49%, over SCE's 2015 recorded adjusted expenses of $7.481 million. For test year 2018, ORA uses a five- year average (2012-2016) and forecasts $7.814 million.[215] ORA's estimate is $1.574 million less than SCE's forecast, but still more than SCE actually spent for storm expenses in 2015.[216]

ORA's use of a five-year average of SCE's most recent data accounts for the inherent variability of costs incurred from storm activity.[217] ORA excluded 2011 expenses of $18.533 million since 2016 expense data was available. SCE's recorded expenses fluctuated slightly averaging $7.101 million for the four year period (2012-2015) after the $12.295 million decline in recorded expenses between 2011 and 2012.

In SCE's test year 2012 GRC, the Commission authorized SCE $18.732 million.[218] SCE's actual 2012 recorded adjusted expenses were $5.517 million, or $13.215 less than authorized.[219]

In SCE's 2015 GRC,[220] the Commission authorized SCE $13.031 million,[221] and SCE's 2015 recorded adjusted expenses were $7.481 million, or $5.550 million less than authorized.

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[213] D.06-05-016, p. 122.

[214] Ex. SCE-2, Vol. 5, p. 63.

[215] Ex. ORA-7, p. 17, footnote 46: SCE provided 2016 recorded adjusted expenses for Account 598.170 - Distribution Storm of $10.667 million in response to data request ORA-SCE-108-TXB, Q.1.

[216] Ex. ORA-7, p. 17.

[217] Ex. ORA-7, p. 17.

[218] Ex. ORA-7, p. 18, footnote 48 citing SCE response to DRA-Verbal-004 and D.12-11-051.

[219] D.12-11-051, p. 211.

[220] D.15-11-021, p. 146.

[221] Ex. ORA-7-WP, p. 7-9 – 7-14 (ORA-SCE-Verbal-006, Q.1).

Given the uncertainty and unpredictability of the weather, and SCE's substantial underspending in this account in the last two GRCs, ORA recommends a one-way balancing account to track and record expenses related to storms and weather disturbances recorded in Account 598.170. Implementing a one-way balancing account will ensure that, if SCE's expenses related to storms or weather disturbances continue to be lower than forecast, as they were after SCE's 2012 and 2015 GRCs, unspent funds will be returned to ratepayers.[222]

4.6 T&D Substation Construction & Maintenance

4.6.1 O&M

Transmission and Distribution – Substation Construction and Maintenance O&M expenses include activities corresponding to SCE's transmission and substations inspection and maintenance activities. Operating expense activities include operating the Grid Control Center (GCC), Inspection and maintenance of substations equipment, Substation operations, Circuit Breaker inspections and maintenance, Substation maintenance crew supervision, Relay inspections and maintenance, Transformer inspections and maintenance and Miscellaneous substations expenses as well as Miscellaneous equipment inspections and maintenance expenses. SCE forecasts $78.1 million for TY 2018 substation construction and maintenance activities.[223]

SCE's 2015 authorized expenses for Substation Construction & Maintenance were $90 million and its 2015 recorded expenses were $83 million. SCE spent $7 million less in 2015 than authorized on Substation Construction & Maintenance expenses.[224]

The table below compares SCE's TY 2018 forecast request and ORA's forecast recommendation for T&D – Substation Construction and Maintenance.

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[222] Ex. ORA-7, p. 18.

[223] Ex. ORA-6, p. 9.

[224] Ex. SCE-02, Vol. 06, p. 5.

SCE's and ORA's T&D Forecast
O&M Expenses for TY 2018
Substation Construction & Maintenance
(in Thousands of 2015 Dollars)[225]

Ferc Account	Description	2018 SCE Forecast	2018 ORA Forecast
561.17	Grid Control Center	$9,813	$9,813
562.150, 582.150	Inspection and Maintenance of Substation Equipment	$1,908	$1,908
562.170, 582.170	Substation Operations	$43,594	$43,594
568.150, 592.150	Miscellaneous Substation Expenses	$2,980	$2,980
568.150, 592.150	Circuit Breaker Inspection and Maintenance	$5,652	$5,652
568.150, 592.150	Substation Maintenance Crew Supervision	$4,344	$4,344
568.150, 592.150	Miscellaneous Equipment Inspection and Maintenance	$4,113	$4,113
568.150, 592.150	Relay Inspection and Maintenance	$3,246	$3,246
568.150, 592.150	Transformer Inspection and Maintenance	$2,499	$2,499
	Total	**$78,150**	**$78,150**

4.7 T&D Transmission Construction & Maintenance

4.7.1 O&M

SCE's Transmission and Distribution – Transmission Construction and Maintenance O&M expenses include activities corresponding to SCE's transmission inspection, maintenance, and construction activities. Transmission inspection activities include routine annual patrols and inspections of SCE's overhead and underground transmission lines and additional inspections during and after storms or other emergencies. Transmission maintenance activities include transmission line maintenance, insulator washing, and road and right-of-way maintenance.[226] In addition, other activities corresponding to Transmission Construction and Maintenance include SCE's transmission line rating remediation, inspection and maintenance of SCE's fiber-optic network and transmission vegetation management.[227]

[225] Ex. ORA-6, p. 10.

[226] Ex. SCE-02, Vol. 07, p. 1.

[227] Id.

SCE forecasts $41.025 million for T&D – Transmission Construction and Maintenance O&M expenses for TY 2018.[228] SCE's TY 2018 forecast of $41.023 million is an increase of $8.293 million compared to 2015 recorded expenses of $32.732 million. [229]

The table below provides SCE's recorded O&M expenses and TY 2018 forecasts of T&D - Transmission Construction & Maintenance:

2011-2015 Recorded / 2018 Forecast
T&D – Transmission Construction & Maintenance
(in Thousands of 2015 Dollars)

FERC Account	Description	2011	2012	2013	2014	2015	2018 Forecast
566.150	Inspection of Transmission Overhead System	$ 6,407	$ 6,554	$ 7,982	$ 5,904	$ 5,208	$ 5,242
566.150	Inspection of Transmission Underground Syster	$ 1,188	$ 1,358	$ 1,231	$ 1,021	$ 1,186	$ 1,201
571.150	Transmission Overhead and Underground Line I	$ 6,502	$ 5,073	$ 4,731	$ 13,442	$ 6,841	$ 6,841
571.150	Transmission Line Rating Remediation	$ -	$ 220	$ 650	$ 980	$ 37	$ 7,600
566.150	Fiber Optic Network Inspection and Maintenanc	$ 951	$ 1,058	$ 1,087	$ 1,516	$ 1,075	$ 1,075
571.150	Transmission Insulator Washing	$ 5,879	$ 5,409	$ 5,445	$ 4,864	$ 396	$ 1,100
571.150	Road and Right of Way Maintenance	$ 5,110	$ 4,837	$ 6,702	$ 6,738	$ 3,645	$ 3,645
571.150	Transmission Vegetation Management	$ 7,405	$ 7,773	$ 7,797	$ 8,509	$ 10,442	$ 10,442
573.170	Transmission/Substation Storm O&M	$ 1,731	$ 2,628	$ 1,094	$ 1,202	$ 1,692	$ 1,669
566.150	Transmission Line Expense	$ 2,882	$ 3,509	$ 2,576	$ 1,657	$ 2,210	$ 2,210
	Total	**$ 38,055**	**$ 38,419**	**$ 39,295**	**$ 45,833**	**$ 32,732**	**$ 41,025**

Source: 2011-2015, 2018 data from Ex. SCE-2, Vol. 07, p. 37-39.

The table below compares SCE's and ORA's TY 2018 forecasts of T&D – O&M expenses for Transmission Construction & Maintenance:

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[228] Ex. SCE-02, Vol. 07, p. 2.

[229] Ex. SCE-02, Vol. 07, p. 4, Figure I-1.

SCE's and ORA's T&D Forecast
O&M Expenses for TY 2018
Transmission Construction & Maintenance
(in Thousands of 2015 Dollars)

FERC Account	Description	SCE's 2018 Forecast	ORA's 2018 Forecast
566.150	Inspection of Transmission Overhead System	$ 5,242	$ 5,242
566.150	Inspection of Transmission Underground System	$ 1,201	$ 1,201
571.150	Transmission Overhead and Underground Line Maintenance	$ 6,841	$ 5,786
571.150	Transmission Line Rating Remediation	$ 7,600	$ 7,600
566.150	Fiber-Optic Network Inspection and Maintenance	$ 1,075	$ 1,075
571.150	Transmission Insulator Washing	$ 1,100	$ 1,100
571.150	Road and Right of Way Maintenance	$ 3,645	$ 3,645
571.150	Transmission Vegetation Management	$ 10,442	$ 9,474
573.170	Transmission/Substation Storm O&M	$ 1,669	$ 1,669
566.150	Transmission Line Expenses	$ 2,210	$ 2,210
	Total	**$ 41,025**	**$ 39,002**

Source: 2018 data from Ex. SCE-2, Vol. 07, p. 2, Table I-1.

After reviewing SCE's testimony, work-papers, data request responses to ORA and historical expense levels for the FERC Accounts, ORA opposes SCE's TY forecast for the following FERC Accounts: 1) Transmission Overhead and Underground Line Maintenance-FERC Account 571.150 and 2) Transmission Vegetation Management-FERC Account 571.150.[230]

Transmission Overhead and Underground Line Maintenance – FERC Account 571.150

Transmission overhead and underground line maintenance includes repairs on transmission line equipment and structures. Maintenance work on the transmission system can be both proactive[231] work identified during regular inspections, or reactive maintenance[232] due to

[230] Ex. ORA-6, p. 12-15.

[231] Ex. SCE-02, Vol. 07, p. 14; Proactive maintenance is performed based on inspection results and analysis of issues found in the field.

[232] Ex. SCE-02, Vol. 07, p. 14; Reactive maintenance is performed when equipment fails in service either due to equipment degradation, weather, animal intrusion, third-party damage or after a fire.

unplanned events.[233] SCE records expenses for overhead and underground line maintenance in FERC Account 571.150.[234]

SCE forecasts $6.84 million[235] for its TY 2018 expenses. ORA's corresponding TY 2018 forecast is $5.79 million.

The table provides SCE's recorded O&M expenses and TY 2018 forecasts of T&D - Transmission Overhead & Underground Line Maintenance:

Transmission Overhead & Underground Line Maintenance
FERC Account 571.150
(in Thousands of 2015 Dollars)

	Recorded					SCE's Forecast	ORA's Forecast
	2011	2012	2013	2014	2015	2018	2018
Labor	$3,730	$3,589	$2,921	$3,551	$4,482	$4,482	$ 3,680
Non-Labor	$2,772	$1,484	$1,811	$9,892	$2,358	$2,358	$ 2,106
Total	$6,502	$5,073	$4,731	$13,442	$6,841	$6,841	$ 5,786

Source: 2018 data from Ex. SCE-2, Vol. 07, p. 38, Table V-13.

SCE based its TY forecast of $6.841 million[236] on last recorded year 2015 to forecast 2018 costs.

ORA reviewed SCE's historical expenses and TY estimate for Transmission Overhead & Underground Line Maintenance. ORA recommends that a forecast based on a 4-year average (2011, 2012, 2013 and 2015) is a much more reasonable approach to estimating TY labor and non-labor expense for Transmission Overhead & Underground Line Maintenance.

Non-labor expenses recorded in last year recorded 2015 are comparable to years 2011-2013; however, non-labor expenses recorded in year 2014 are substantially and unusually higher than 2011-2013 and most recent year 2015.

[233] Ex. SCE-02, Vol. 07, p. 14.

[234] Ex. ORA-6, p. 13.

[235] Ex. SCE-02, Vol. 07, p. 14.

[236] Ex. SCE-02, Vol. 07, p. 14.

For 2014 level of expenses, SCE states:

> In 2014, SCE performed significant programmatic maintenance activities, especially in the areas of tower painting, torqueing, insulator replacement, and overhead conductor repair. SCE does not anticipate performing programmatic maintenance at this level going forward. Labor expenses are for SCE crews and personnel performing transmission maintenance. Non-labor expenses include costs for contract crews, and allocated costs for vehicles and other allocated overheads. The total costs in this activity vary from year-to-year based on unplanned equipment breakdown, and the number of issues identified during inspections.[237]

SCE also states:

> … In addition, 2014 is not representative of future spend due to the abnormally high amount of work performed that year.[238]

Using a 4-year average (2011, 2012, 2013 and 2015) is the most reasonable approach to estimating labor and non-labor expenses for this FERC Account. ORA recommends $5.786 million for TY 2018 for Transmission Overhead & Underground Line Maintenance expenses.[239]

Transmission Vegetation Management - FERC Account- 571.150

Transmission Vegetation Management includes all of the expenses associated with tree trimming and tree removal in proximity to transmission and distribution high voltage lines, and weed abatement around overhead structures in high fire designated areas in proximity to transmission and distribution high voltage lines. It also includes costs of planting different species of trees as replacements and in handling preventive soil treatment. The majority of costs are from a fixed price contract with SCE's tree trimming contractors, which requires them to maintain compliance for the approximately 1.5 million trees that exist in proximity to energized conductors throughout SCE's service territory.[240] SCE's TY 2018 forecast is based on last year

[237] Ex. SCE-02, Vol. 07, p. 15.

[238] Ex. SCE-02, Vol. 07, p. 15.

[239] Ex. ORA-6, p. 14.

[240] Ex. SCE-02, Vol. 07, p. 24.

recorded 2015. [241] SCE's vegetation management for Transmission assets are recorded to GRC account 571.150.[242]

The table below provides SCE's recorded O&M expenses and compares SCE's and ORA's TY 2018 forecasts of T&D-Transmission Vegetation Management.

2011-2015 Recorded / 2018 Forecast
Transmission Vegetation Management
FERC Account 571.150
(in Thousands of 2015 Dollars)

	Recorded					SCE's Forecast	ORA's Forecast
	2011	2012	2013	2014	2015	2018	2018
Labor	$ 377	$ 494	$ 361	$ 772	$ 1,133	$ 1,133	$ 952
Non-Labor	$ 7,028	$ 7,279	$ 7,436	$ 7,736	$ 9,310	$ 9,310	$ 8,522
Total	**$ 7,405**	**$ 7,773**	**$ 7,797**	**$ 8,508**	**$ 10,443**	**$ 10,443**	**$ 9,474**

Source: 2011-2015, 2018 data from Ex. SCE-2, Vol. 07, p. 38, Table V-13.

For SCE's Transmission Vegetation Management, SCE seeks $10.4 million[243] for TY 2018.

SCE states that labor expenses are driven by the work performed by SCE arborists and employees that manage the vegetation management program and non-labor costs include contractor costs and charges associated with the vegetation management program.

ORA forecasts TY Transmission Vegetation Management labor and non-labor expenses, by using a 2-year average that takes into account SCE's most recent recorded years (2014 and 2015) since these two years, 2014 and 2015 include recent SCE's changes in contractor terms and more recent costs. ORA agrees with SCE's statement that:

> Labor and non-labor costs, collectively, for vegetation management remained relatively stable from 2011 to 2013. Costs increased in 2014 due to a change in contract terms, and have since stabilized. SCE expects to continue to perform the same level of activities in this area going forward. [244]

[241] Ex. SCE-02, Vol. 07, p. 25, Table II-11.

[242] Ex. ORA-6, p. 15.

[243] Ex. SCE-02, Vol. 07, p. 38.

[244] Ex. SCE-02, Vol. 07, p. 25.

ORA reviewed SCE's historical expenses and recommends $9.4 million ($952,000 for labor and $8.522 million for Non-labor) for this account based on the reasons discussed above.[245]

4.8 T&D - Adjustments to Infrastructure Replacement Projects

As equipment ages, the risk of experiencing failures generally increases. The capital projects included within the Infrastructure Replacement area seek to replace pieces of equipment prior to their failure based on a risk/reliability evaluation. Stated another way, these programs preemptively replace pieces of equipment that are still operational, based on various studies that show they may soon fail. There are 11 project categories that make up the Infrastructure Replacement area. Of these 11 categories, ORA is recommending adjustments to eight of them. However, seven of these eight adjustments are either due to corrections to SCE's original estimates, or are minor rounding adjustments. Only one of ORA's recommended adjustments, addressing issues with SCE's new Overhead Conductor Program (OCP), are protested by SCE (as well as CUE).[246]

In Exhibit ORA-08, there are detailed discussions of the OCP. SCE presents its Infrastructure Replacement testimony in Exhibit SCE-02, Volume 08. References to SCE's Rebuttal testimony refer to SCE-18, Vol. 08. All references to SCE's Direct and Rebuttal testimony in the remainder of this section of this Brief refer to those specific SCE exhibits.

Overhead Conductor Program

SCE described in detail in direct testimony its new Overhead Conductor Program (OCP) as folllows:

> The goals of the Overhead Conductor Program are to reduce the frequency and impact of wire down events by executing proactive overhead conductor replacement projects, reactive emergency wire down work during events, and reactive planned conductor work after wire down events. Similar to the WCR program that focuses on the worst performing circuits to addresses reliability risks, OCP ranks overhead circuits based on criteria such as specific increased likelihood of wire down events to address safety and reliability risks.[247]

In its analysis of this new program, ORA agrees that the OCP is a worthwhile program, but questions whether SCE would be able to complete all of the capital expenditures that it had

[245] Ex. ORA-6, p. 16.

[246] California Coalition of Utility Employees.

[247] Ex. SCE-2, Vol 8, p. 47.

proposed for 2017 and 2018. SCE proposes OCP replacement levels of 300 circuit-miles in 2017, and an additional 300 circuit-miles in 2018. ORA recommends replacement levels of 200 and 250 circuit-miles in 2017 and 2018, respectively. In their respective Rebuttal testimonies, both SCE and CUE challenged ORA's analyses and recommendations.

SCE's alleges in its Rebuttal (beginning on line 6, page 9) that ORA's analyses of the OCP were based on SAIDI/SAIFI[248] reliability arguments, while the OCP was primarily designed to improve safety. However, SCE fails to point out that ORA's analyses focused on reliability by necessity. ORA was unable to find any type of SCE-developed model/methodology, in either SCE's testimony or work papers, that would allow an interested party to quantify the safety impacts of overhead cable replacements. In fact, ORA was unable to find any discussion/analyses in SCE's testimony or work papers that demonstrated how SCE derived its OCP forecasts. ORA's testimony regarding OCP is equally applicable to both the safety and the reliability aspects of that new program.

Closely related to its previous allegation, SCE also alleges that ORA overlooked the fundamental safety risk driver of the OCP.[249] As mentioned previously, ORA carefully searched SCE's testimony and work papers, but was unable to locate any type of SCE-developed model/methodology that SCE may have used to derive its 300 circuit-mile forecasts for the OCP for 2017 and 2018. ORA was also unable to find any type of SCE-developed model/methodology that would allow an interested party to quantify the safety impacts of overhead cable replacements.

Stated simply, ORA's OCP replacement goal was to ensure improved safety and reliability, while simultaneously remaining cognizant of the fact that the OCP is a new program, and that SCE is continuing to refine its criteria for selecting OCP projects. ORA's recommended 2017 replacement level of 200 circuit-miles is 2.7 times the quantity replaced in 2015 (which is the last year for which ORA had recorded replacement data); ORA's recommended 2018 level of 250 circuit-miles is 3.4 times greater. Since SCE's recorded 2015 replacement levels were designed to improve safety, and since ORA's 2017 and 2018 replacement recommendations are

[248] System Average Interruption Duration Index/System Average Interruption Frequency Index.

[249] Ex. SCE-18, Vol. 8.

multiple times larger than the recorded 2015 amount, ORA's replacement recommendations will result in even greater safety improvements than SCE's.

ORA also took into consideration the fact that in 2016, SCE spent $44.873 million less than its 2016 forecast. Combining this lower expenditure with the fact that SCE's testimony states that the OCP is continuing to evolve, one can conclude that a "ramping up" of OCP expenditures was occurring. In ORA's judgment, forecasts of 200 circuit-miles in 2017 and 250 circuit-miles in 2018 will ensure that overhead wire safety will be much improved; at the same time, these forecasts will also reflect the expected "ramping up" of projected OCP projects.

Throughout page 10 of its Rebuttal**,** SCE alleges that ORA has erroneously concluded that reliability analyses, which hold overhead conductor failure rates constant, will automatically understate the reliability impacts of the OCP. Stated more simply, SCE alleges that ORA cannot know if reliability will improve under the OCP – if OCP reliability improvements are not sufficient to offset line degradation, then reliability may actually decrease

SCE's Rebuttal contains the same two fundamental flaws. First, as SCE states in footnote 20 (page 10) of its Rebuttal, "overhead conductor reliability performance was held constant for all simulations in this rate case." Stated another way, SCE's reliability analyses were based on a continuation of the historical overhead conductor failure rates. SCE has not presented evidence, that the overhead failure rate is going to suddenly worsen. Given that the new OCP is now operational (and is designed to improve overhead reliability), and given that the record in this case is for a sudden worsening of overhead line reliability, one can conclude that the continued funding of the OCP will result in increased system reliability. SCE does not mention that in earlier portions of SCE's Direct testimony, SCE concluded that:

> The analysis concludes that approximately 350 conductor-miles of primary mainline underground cable must be preemptively replaced each year to achieve, in 20 years, approximately today's level of SAIDI.[250]

As discussed in the footnote below, as part of its Worst Circuit Replacement (WCR) testimony, SCE has concluded that the yearly replacement of 350 circuit-miles of cable under the

[250] Ex. SCE-02, Vol. 08, p. 6, lines 2 through 4. This discussion pertains to the Worst Circuit Reliability (WCR) program. As part of its analysis on this subject, SCE concluded that the replacement of 350 conductor-miles of underground cable would be sufficient to maintain system reliability over the next 20 years. ORA has recommended that SCE's 350 circuit-mile forecast be adopted, thereby ensuring that system reliability will not be degraded.

WCR program will be sufficient to ensure that 20 years hence, its system reliability will be the same as it is currently. Given that ORA has not recommended any adjustments to that program, it necessarily follows that SCE's reliability will not decrease. Given that reliability decreases would likely occur if SCE actually expected the reliability of overhead lines to suddenly change, provides additional evidence that it is not only unrealistic, but it is inaccurate to assume that failure rates for overhead lines will suddenly increase.

SCE's next Rebuttal discussion begins on page 11, line 20. SCE states that it disagrees with ORA's characterization that preemptive line replacement levels have "skyrocketed." To justify that disagreement, SCE compares proposed replacement levels to the total inventory of linear assets in SCE's system, and concludes that its proposed replacement levels are "modest" in comparison.

ORA asserts it is not only misleading, but meaningless, to compare proposed preemptive replacement levels to the total miles of cable in SCE's entire distribution system. In order to evaluate how preemptive replacement levels have evolved, the relevant analysis involves comparing SCE's proposed replacement levels with historical replacements. To that end, ORA developed Table 8-2 on page 17 of its testimony, a copy of which is reprinted below.

In Table 8-2, ORA tabulated all of the programs in which SCE has proposed preemptive replacements of distribution cables. In order to compare "apples to apples," ORA converted all of the historical and proposed replacement levels to conductor-miles, thereby ensuring that all of the measurements were comparable. Columns (i) and (j) show replacement levels for the OCP, while columns (k) and (l) show the sum of the replacement levels for all of the proposed programs. As shown on line 2 of Table 8-2, as recently as 2012, only 207 conductor-miles of preemptive replacements in total were undertaken. Lines 7 and 8 show that by 2017 and 2018, SCE has proposed that 1,315 and 1,350 conductor-miles (in total) be replaced, while ORA recommends 1,065 and 1,225 conductor-miles, respectively. Comparing ORA's recommendations to the 207 conductor-mile replacement level that occurred in 2012, the resulting percentage increases amount to 414% for 2017 and 492% for 2018.[251] By any reasonable definition of the word, these levels of increases can fairly be called "skyrocketing.

[251] (1,065-207)÷207=4.14 for 2017. (1,225-207)÷207=4.92 for 2018.

Table 8-2
TOTAL PREEMPTIVE CABLE REPLACEMENTS
(Conductor-Miles)

Line #	Year	UNDERGROUND REPLACEMENTS								OVERHEAD REPLACEMENTS		TOTAL	
		Quantity of WCR Replacements (Conductor-Miles)		Quantity of CIC Injections (Conductor-Miles)		Quantity of CIC Replacements (Conductor-Miles)		Total Underground Replacements (Conductor-Miles)		Quantity of Overhead Replacements (Approximate Conductor-Miles)		Total Preemptive Replacements (Conductor-Miles)	
		SCE	ORA	SCE	ORA	SCE	ORA	SCE	ORA	SCE	ORA	SCE	ORA
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2011 - Recorded	296	296	0	0	1	1	297	297	0	0	297	297
2	2012 - Recorded	192	192	0	0	15	15	207	207	0	0	207	207
3	2013 - Recorded	300	300	1	1	21	21	322	322	0	0	322	322
4	2014 - Recorded	403	403	7	7	68	68	478	478	0	0	478	478
5	2015 - Recorded	283	283	36	36	133	133	452	452	185	185	637	637
6	2016 - Forecast	400	n.a	90	n.a	100	n.a	590	n.a	800	n.a	1390	n.a
7	2017 - Forecast	350	350	100	100	115	115	565	565	750	500	1315	1065
8	2018 - Forecast	350	350	100	100	150	150	600	600	750	625	1350	1225

n.a. = not available; recorded data not provided at this level of detail. ORA made no forecasts for these numbers as they were not needed for the development of the 2016 recorded data shown on Table 8-1.

On page 12 of its Rebuttal**,** SCE next alleges that increases of this magnitude are not uncommon. SCE cites Cable-In-Conduit (CIC) replacements as an example of a capital program that experienced substantial increases. This example is rather meaningless, since it is akin to a circular argument because the CIC program is itself a component of (and one of the reasons for) the "skyrocketing" increase that ORA has identified in Table 8-2. (See Columns (c), (d), (e), and (f) in Table 8-2.) ORA stands by its contention that increases of this magnitude, over such a short period, are indeed uncommon.

Beginning on line 4 of page 12, SCE states that as new problems are identified, prudent utility operators should pursue new activities to address these problems. ORA is not philosophically opposed to that proposition. However, that does not mean that a utility should be given a "carte blanche" pass to spend whatever it wants. Judgment, common sense, and careful analyses are always necessary when evaluating proposed increases of this magnitude. As discussed previously, ORA took into consideration the fact that in 2016, SCE spent $44.873 million less than its 2016 forecast.

Combining this lower expenditure with the fact that SCE's testimony states that the OCP is continuing to evolve, led ORA to conclude that a "ramping up" of OCP expenditures was occurring. Forecasts of 200 circuit-miles in 2017, and increasing to 250 circuit-miles in 2018, will ensure that overhead wire safety will be much improved; at the same time, these forecasts will also reflect the expected "ramping up" of projected OCP projects.

SCE also disputes ORA's conclusion that OCP expenditures can be reasonably expected to "ramp up." Beginning on line 18 of page 12, SCE contends that in 2016 it completed "202 miles of its planned scope of 204 miles." This statement is factually incorrect.

On page 49 of its Direct testimony, SCE provides Table III-12, which shows the details of SCE's calculation for OCP expenditures. Table III-12 is reprinted below.

Table III-12
Historical and Forecast Spend for OCP[34]

Year	Recorded/Forecast Replacements Overhead Conductor (Circuit-miles)	Forecast Unit Cost of Overhead Conductor Replacement (Nominal dollars x 1,000)	Recorded/Forecast Cost of Overhead Conductor Replacements (Nominal dollars x 1,000)
2011			
2012			
2013			
2014			
2015	74		$58,126
2016	320	$444	$142,203
2017	300	$454	$136,087
2018	300	$465	$139,514
2019	300	$480	$143,891
2020	300	$495	$148,466

As shown in the second column, SCE explicitly shows that it has forecast OCP replacement levels of 300 circuit-miles for each of the years 2017 through 2020. In response to Data Request TURN-SCE-059, Question 01.b.iii, SCE provided an Excel spreadsheet in which it purportedly derives its new scope of completing only 204 circuit-miles. On page A-14 of its Rebuttal, SCE provides a copy of this data request response, along with an embedded link to the Excel spreadsheet, a portion of which ORA has reproduced on the following page.

As shown in the first column, ORA has only included those projects that were forecast for 2016. (At the bottom of this table, ORA has (in red) provided column summaries.) Summing the circuit-miles listed in the fourth column gives a total of 203.9, which is apparently how SCE derived its new completion scope of 204 circuit-miles. Assuming, that the Commission accepts as reasonable this new completion total, the 204 circuit-mile total is still not accurate. The table after next only includes those 2016 projects that are shown as having been completed (where the Project Completed column "Yes").

Project Year	Total Estimate	Reactive / Proactive	Circuit Miles	BLF Count	Project Completed
2016	$5,327,560	Proactive	11.53	224	Yes
2016	$2,999,095	Proactive	6.67	28	Yes
2016	$2,271,415	Reactive	2.92	47	Yes
2016	$1,543,098	Reactive	1.11	16	
2016	$2,869,436	Proactive	5.03	66	Yes
2016	$5,103,049	Proactive	4.83	59	
2016	$28,552	Reactive	0.00	0	Yes
2016	$10,249	Reactive	0.01	2	
2016	$5,705,231	Proactive	7.78	75	Yes
2016	$9,872	Reactive	0.00	3	
2016	$6,825,320	Proactive	10.23	141	
2016	$1,964,041	Proactive	2.19	44	
2016	$467,417	Reactive	0.95	9	
2016	$129,162	Reactive	0.00	2	Yes
2016	$534,940	Reactive	0.70	0	Yes
2016	$2,524,919	Reactive	2.03	22	Yes
2016	$567,407	Reactive	0.71	5	Yes
2016	$4,799,586	Reactive	3.49	26	Yes
2016	$6,599,206	Proactive	7.32	47	
2016	$112,289	Reactive	0.12	0	Yes
2016	$1,638,016	Reactive	2.18	32	Yes
2016	$354,407	Reactive	0.63	22	Yes
2016	$369,482	Reactive	0.66	35	Yes
2016	$5,539,991	Proactive	4.97	36	
2016	$1,034,936	Reactive	1.74	26	Yes
2016	$3,653,902	Proactive	6.60	79	Yes
2016	$915,427	Reactive	0.99	72	Yes
2016	$310,254	Reactive	0.64	10	Yes
2016	$4,024,979	Proactive	5.40	80	Yes
2016	$11,806	Reactive	0.00	3	
2016	$47,586	Reactive	0.11	0	Yes
2016	$2,972,049	Proactive	3.26	49	Yes
2016	$3,538,485	Proactive	7.06	116	
2016	$248,835	Reactive	0.39	6	Yes
2016	$1,322,734	Proactive	2.20	26	Yes
2016	$12,198	Reactive	0.00	3	
2016	$8,110,558	Proactive	10.20	106	
2016	$11,964	Reactive	0.00	3	
2016	$12,353	Reactive	0.00	8	
2016	$1,013,510	Reactive	1.37	15	Yes
2016	$2,370,422	Proactive	3.96	112	Yes
2016	$2,710,111	Proactive	2.30	38	
2016	$529,275	Reactive	0.73	3	Yes
2016	$1,484,486	Reactive	0.77	20	Yes
2016	$228,101	Reactive	0.17	4	Yes
2016	$456,673	Reactive	0.86	0	Yes
2016	$177,784	Reactive	0.25	5	Yes
2016	$5,208,811	Reactive	2.43	28	Yes
2016	$839,100	Reactive	1.59	2	
2016	$1,370,488	Reactive	2.75	15	Yes
2016	$195,702	Reactive	0.24	5	Yes
2016	$116,616	Reactive	0.00	0	Yes
2016	$2,499,298	Reactive	4.55	0	
2016	$2,808,537	Reactive	2.08	24	Yes
2016	$13,335	Reactive	0.00	3	
2016	$91,101	Reactive	0.12	6	Yes
2016	$8,114,003	Proactive	17.02	203	Yes
2016	$3,473,778	Proactive	7.73	154	Yes
2016	$13,476	Reactive	0.00	4	
2016	$173,726	Reactive	0.10	4	Yes
2016	$11,806	Reactive	0.00	3	
2016	$3,014,581	Proactive	3.33	84	
2016	$2,233,250	Proactive	2.77	82	
2016	$3,725,304	Proactive	4.50	56	Yes
2016	$1,552,988	Proactive	4.17	0	Yes
2016	$6,096,384	Proactive	12.32	124	
2016	$4,338,557	Proactive	8.99	220	Yes
2016	$1,618,642	Proactive	2.03	4	
2016	$13,596	Reactive	0.00	3	Yes
2016	$1,187,737	Reactive	2.17	14	Yes

Only 2016 Projects	**Total = $142,202,984**		**Total = 203.9 Miles**	**Total = 2,763**	**Total Completed and Not Completed Through 2/17 = 70 Projects**

Project Year	Total Estimate	Reactive / Proactive	Circuit Miles	BLF Count	Project Completed
2016	$5,327,560	Proactive	11.53	224	Yes
2016	$2,999,095	Proactive	6.67	28	Yes
2016	$2,271,415	Reactive	2.92	47	Yes
2016	$2,869,436	Proactive	5.03	66	Yes
2016	$28,552	Reactive	0.00	0	Yes
2016	$5,705,231	Proactive	7.78	75	Yes
2016	$129,162	Reactive	0.00	2	Yes
2016	$534,940	Reactive	0.70	0	Yes
2016	$2,524,919	Reactive	2.03	22	Yes
2016	$567,407	Reactive	0.71	5	Yes
2016	$4,799,586	Reactive	3.49	26	Yes
2016	$112,289	Reactive	0.12	0	Yes
2016	$1,638,016	Reactive	2.18	32	Yes
2016	$354,407	Reactive	0.63	22	Yes
2016	$369,482	Reactive	0.66	35	Yes
2016	$1,034,936	Reactive	1.74	26	Yes
2016	$3,653,902	Proactive	6.60	79	Yes
2016	$915,427	Reactive	0.99	72	Yes
2016	$310,254	Reactive	0.64	10	Yes
2016	$4,024,979	Proactive	5.40	80	Yes
2016	$47,586	Reactive	0.11	0	Yes
2016	$2,972,049	Proactive	3.26	49	Yes
2016	$248,835	Reactive	0.39	6	Yes
2016	$1,322,734	Proactive	2.20	26	Yes
2016	$1,013,510	Reactive	1.37	15	Yes
2016	$2,370,422	Proactive	3.96	112	Yes
2016	$529,275	Reactive	0.73	3	Yes
2016	$1,484,486	Reactive	0.77	20	Yes
2016	$228,101	Reactive	0.17	4	Yes
2016	$456,673	Reactive	0.86	0	Yes
2016	$177,784	Reactive	0.25	5	Yes
2016	$5,208,811	Reactive	2.43	28	Yes
2016	$1,370,488	Reactive	2.75	15	Yes
2016	$195,702	Reactive	0.24	5	Yes
2016	$116,616	Reactive	0.00	0	Yes
2016	$2,808,537	Reactive	2.08	24	Yes
2016	$91,101	Reactive	0.12	6	Yes
2016	$8,114,003	Proactive	17.02	203	Yes
2016	$3,473,778	Proactive	7.73	154	Yes
2016	$173,726	Reactive	0.10	4	Yes
2016	$3,725,304	Proactive	4.50	56	Yes
2016	$1,552,988	Proactive	4.17	0	Yes
2016	$4,338,557	Proactive	8.99	220	Yes
2016	$13,596	Reactive	0.00	3	Yes
2016	$1,187,737	Reactive	2.17	14	Yes

Only 2016 Projects	**Total = $83,393,394**		**Total = 126.16 Miles**	**Total = 1,823**	**Total Completed Through 2/17 = 45 Projects**

The only difference between this second spreadsheet and the first is that only projects completed by February 2017 are included; this can be seen in the last column (Project Completed), where all the projects are shown as "Yes." As ORA has shown in its comments (in red) at the bottom of this second table, if only the OCP projects that were actually completed through February 2017 are included in the spreadsheet, only 126.16 circuit-miles were actually finished, not the revised 204 circuit-miles that SCE now states was its ultimate goal for 2016. Therefore, whether one uses SCE's initial goal of completing 300 circuit-miles, or one uses the revised 204 circuit-mile figure, the results are the same -- SCE was not able to complete all of the projects it had forecast in 2016 for the OCP. Therefore, rather than showing that SCE had been able to successfully complete all of its OCP forecast replacements, the spreadsheet included on page A-14 of its Rebuttal clearly shows that SCE is still in the process of "ramping up" its forecast OCP completions.

As discussed previously, in developing its OCP recommendations, ORA took into consideration the fact that in 2016, SCE actually spent $44.873 million less than its 2016 forecast. Combining this lower expenditure with the fact that SCE's testimony states that the OCP is continuing to evolve, led ORA to conclude that a "ramping up" of OCP expenditures was occurring. Logic would therefore dictate that ORA's forecasts should reflect that conclusion. The Excel spreadsheet included on page A-14 provides confirmation that ORA's judgment regarding the "ramping up" of OCP expenditures is correct.

4.9 T&D Poles - Capital

ORA's Distribution Maintenance & Inspection forecast differs from SCE's forecast on only the 2016 program year. ORA's forecast is based on the recorded expenditure data SCE provided.[252] ORA accepts SCE's forecast for program years 2017 and 2018 for the Distribution Maintenance & Inspection Programs.

ORA's Poles forecast differs from SCE's forecast on only 2016. ORA's 2016 forecast is based on the recorded expenditure data SCE provided.[253] ORA accepts SCE's forecast for 2017 and 2018 for the Poles Programs.[254]

[252] SCE response to data request ORA-SCE-108-TXB.

[253] SCE response to data request ORA-SCE-108-TXB.

[254] Ex. ORA-10, p. 3-4.

ORA only discussed capital expenditures and did not specifically address SCE's capital additions. Capital expenditures reflect the capital dollars that SCE spends in a given year. No consideration is given as to whether or not those expenditures result in projects that are actually completed (and considered to be "used and useful") during the year. In contrast, capital additions reflect the dollar amount of projects that are completed during a given year, regardless of when the expenditures actually took place. SCE presents its testimony and workpapers using the "expenditure" format. SCE's Results of Operations (RO) computer model takes these expenditures and converts them to capital additions using project completion dates that are loaded into the model.[255]

4.9.1 Distribution Maintenance and Inspection Programs

Distribution Maintenance and Inspection programs include: 1) Preventative Maintenance; 2) Breakdown Maintenance and 3) Remove Idle Facilities Program.

SCE's request for program years 2016-2018 is based on the historical average of the 2011-2015 expenditures for the Distribution Maintenance and Inspection and Remove Idle Facilities Programs.[256] However, SCE's recorded capital for 2016 was $16 million, or six percent higher than SCE's request. Based on this fact, ORA's review, and that SCE's 2017-18 forecasts use on the Commission-encouraged five-year average, ORA accepts SCE's forecast.[257]

4.9.2 Poles Program

SCE's Capital Poles Program include about 1.4 million poles spread over its 50,000 square mile service territory.[258] The capital expenditure activities related to poles include repairs, replacements, and disposal.

The major pole programs are the (1) Pole Loading Replacements Programs and the (2) Deteriorated Pole Replacement and Restoration Programs. Each program is segmented by Distribution or Transmission WBS reporting categories. For 2018, the Pole Loading Replacements Programs total $144 million of the capital expenditure request, and the Deteriorated Pole Replacement and Restoration Programs total $242 million.[259]

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[255] Ex. ORA-10, p. 6.

[256] Ex. SCE-02, Vol. 4, p. 14, lns. 4-5 and p. 16, lns. 7-9.

[257] Ex. ORA-10, p. 10.

[258] Ex. SCE-02, Vol. 09, p. 30, lns. 4, 29.

[259] Ex. ORA-10, pp. 10 and 12.

Pole Loading Distribution Pole Replacements and Pole Loading Transmission Poles Replacements

The Pole Loading Program (PLP) is relatively new; initial activities began in 2014, and SCE adopted the program in the 2015 General Rate Case. The program is driven by the Commission's General Order (G.O.) 95 -- Design, Construction and Maintenance of Overhead Lines. GO 95 requires that newly installed poles meet minimum safety standards.[260] SCE states:

> The main risk associated with poles that do not meet minimum safety factor requirements is that they may break or fail at wind loads below the minimum design wind loads for that geographic location, resulting in increased risk to public safety and system reliability.[261]

The PLP is designed to systematically assess all poles and replace or repair the poles that do not meet minimum G.O. 95 standards.[262]

The capital expenditures' forecast in the PLP program is driven by the number of poles replaced and their unit costs. The poles replacement forecast is based on the number of assessments and an assessment "reject rate." SCE is using an assessment reject rate of 9 percent for this GRC forecast.[263] Other factors which impact the forecast are scheduling and permitting issues, geographic "grouping" and safety concerns such as high fire zones or other damaging influences.[264]

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[260] Ex. SCE-02, Vol. 9, p. 31, lns. 6-9.

[261] Ex. SCE-02, Vol. 9, p.10, lns. 13-15.

[262] Ex. ORA-10, p. 12.

[263] Ex. SCE-02, Vol. 9, p. 16, ln. 5.

[264] Ex. SCE-02, Vol. 9, p. 22, ln. 26 and p. 10, ln. 11; workpapers, p. 116.

Poles Capital Expenditures for 2016-2018
SCE Proposals & ORA Adjustments

	Poles Capital						
SCE-02Vol. 09	Nominal, $000						
WBS Description	SCE 2016	ORA ADJ.	ORA 2016	SCE 2017	ORA 2017	SCE 2018	ORA 2018
Prefabrication Capital Expenditures, PLP Portion	3,260	-742	2,518	3,638	3,638	4,088	4,088
Joint Pole Capital Credit, Distribution	-7,626	-12	-7,638	-8,057	-8,057	-8,585	-8,585
Joint Pole Capital Credit, Transmission	-388	-76	-464	-709	-709	-1,084	-1,084
Joint Pole Capital Credit, Transmission	-9,513	9,513	0	-9,424	-9,424	-8,763	-8,763
Distribution Deteriorated Pole Replacement and Restoration	219,123	52,667	271,790	193,402	193,402	177,355	177,355
Pole Capital Savings	0	0	0	-12,965	-12,965	-12,529	-12,529
Joint Pole Capital Credit, Distribution	-46,791	-75	-46,866	-43,558	-43,558	-42,181	-42,181
Transformer Capital Expenditures, PLP Portion	4,804	-1,093	3,711	5,360	5,360	6,024	6,024
Transmission Deteriorated Pole Replacement and Restoration	0	0	0	0	0	64,362	64,362
Wood Pole Disposal	1,106	44	1,150	1,234	1,234	1,387	1,387
Wood Pole Disposal	2,637	104	2,741	2,378	2,378	2,161	2,161
Pole Loading Distribution Pole Replacements	106,353	-17,368	88,985	112,368	112,368	119,731	119,731
Pole Loading Transmission Pole Replacements	8,808	1,951	10,759	16,116	16,116	0	0
Pole Loading Transmission Pole Replacements	0	0	0	0	0	24,628	24,628
Transmission Deteriorated Pole Replacement and Restoration	82,748	4,811	87,559	76,451	76,451	0	0
Pole Capital Savings	-4,002	4,002	0	-6,872	-6,872	-8,604	-8,604
Totals	**360,519**	**53,726**	**414,245**	**329,362**	**329,362**	**317,990**	**317,990**

ORA focused on the Pole Loading Programs and Deteriorated Poles Programs when assessing the overall reasonableness of SCE's Poles Programs capital expenditure request. Reviewing the Table above, comparing SCE's original 2016 program year request with the actual 2016 expenditures (the ORA 2016 column) is helpful. For the combined Pole Loading Programs, 2016 spending was about 13 percent below SCE's request. For the combined Deteriorated Poles Programs, 2016 spending was about 19 percent above SCE's request. ORA recommends the Commission adopt the recorded 2016 expenditures as the 2016 forecast.[265]

For the 2017 and 2018 Poles Programs, SCE forecasts steady to declining capital expenditures for the major program areas. Along with the impact of the increasing credits from the Joint Capital Credits Programs, SCE's poles capital expenditures are forecast to decline by 23 percent when comparing the overall 2018 forecast to the 2016 recorded spending.

ORA reviewed the input assumptions and programmatic details of all the poles programs activities, and found them reasonable. Based on this review, and the overall declining forecast for the Poles Programs capital expenditures, ORA accepts SCE's 2017 and 2018 forecasts. ORA recommends adopting the recorded data for program year 2016.

[265] Ex. ORA-10, pp. 15-16.

Pole Loading and Deteriorated Poles Program Balancing Account

SCE proposes modifying the Pole Loading and Deteriorated Poles Programs Balancing Account (PLDPBA).[266] SCE adopted the PLDPBA in the 2015 GRC.[267] As filed, the two-way balancing account records the difference between: (1) recorded capital-related revenue requirements for the Pole Loading Program and Deteriorated Pole Program, (2) Operation and Maintenance (O&M) expenses for the Pole Loading Program, and (3) the authorized Pole Programs revenue requirement as adopted in D.15-11-021.[268] The account is capped at 15 percent above the adopted forecast amounts for 2016 and 2017, while there is no cap for 2015.[269] SCE reports that the 2015 recorded operation of the PLDPBA reflects an over-collection (i.e., under spending) of $36.2 million.[270] SCE states that it will provide the recorded operation of the PLDPBA for 2016 in supplemental testimony in this proceeding.[271]

SCE proposes removing the 15 percent cap on Pole Loading and Deteriorated Pole Program spending, beginning in 2018.[272] SCE argues that there is still uncertainty associated with the pole cost per unit estimates because there are potential events beyond SCE's control which impact pole safety and reliability and that there is still a lack of experience with pole restoration.[273]

The Commission should reject SCE's proposal to modify the PLDPBA because: 1) there is just one year of available 2015 recorded data for the balancing account and it shows an over-collection; 2) the cap applies to 2016 and 2017, where there is no recorded information to evaluate the impact of the 15 percent cap and 3) SCE's argument that there is cost uncertainty with the pole replacement programs is not consistent with the overall showing and cost forecasts

[266] Exs. SCE-02, Vol. 9, p. 79 and SCE-09, Vol. 1, pp. 30-32.

[267] D.15-11-021, O.P. 8.

[268] Ex. SCE-09, Vol. 1, p. 30.

[269] D.15-11-021, O.P. 8.

[270] Ex. SCE-09, Vol. 1, p. 31.

[271] Ex. SCE-09, Vol. 1, p. 32.

[272] Ex. SCE-09, Vol. 1, p. 32.

[273] Ex. SCE-09, Vol. 1, p. 32.

in its Poles exhibit. A full cycle of recorded data will be available in the next GRC where any appropriate modifications to the balancing account may be addressed.[274]

4.9.3 O&M

SCE's Pole expenses include costs for inspection and remediation of poles as part of SCE's Deteriorated Pole Program, and its Pole Loading Program (PLP). SCE says its Pole Loading Program identifies poles for repair or replacement if the poles do not meet safety requirements. The safety requirements include wind loading tests.[275]

SCE forecasts $43.559 million for Poles expenses.[276] SCE developed its forecast by using its 2015 recorded adjusted expenses as a basis, and then adding incremental expenses for proposed test year projects and activities. The corresponding ORA estimate for SCE's Poles expenses is $33.959 million. ORA's estimate is $9.600 million less than SCE's forecast.[277]

SCE combined the forecast expenses from four FERC sub-accounts to calculate its forecast of $43.559 million for its forecast of Poles expenses.[278] Of the four FERC sub-accounts, ORA disputes SCE's forecasts for three of them. The three ORA disputes are FERC sub-account 566.125, which include expenses for both Transmission Intrusive Pole Inspections and Transmission Pole Loading Program, FERC sub-account 583.125, Distribution Intrusive Pole Inspections, Joint Pole Credits, Distribution Pole Loading Assessments and Joint Pole Organization, and FERC sub-account 593.125, Distribution Pole Loading Program Capital – Related expenses and Distribution Pole Loading Program Repairs.[279]

SCE's Total TY 2018 forecast for its Poles expenses was $43.559 million.[280] This is an increase of $15.523 million, or 55.37%, over SCE's 2015 recorded adjusted expenses of $28.036 million. SCE's recorded adjusted expenses increased by $24.028 million between 2011 and

[274] Ex. ORA-10, p. 17.

[275] Ex. SCE-2, Vol. 9, p. 1.

[276] Ex. SCE-2, Vol. 9, p. 5.

[277] Ex. ORA-7, p. 18.

[278] Ex. ORA-7, p. 19.

[279] Ex. ORA-7, p. 19, Figure 7-3.

[280] Ex. SCE-2, Vol. 9, pp. 80-83.

2014. SCE says this increase was partly due to the implementation of SCE's Pole Loading Program in January 2014.[281]

SCE's recorded adjusted expenses declined by $3.344 million between 2014 and 2015 from $31.380 million to $28.036 million. SCE says it:

> … performed approximately 63,000 fewer assessments than originally forecasted for the Pole Loading Program in 2015, which led to significantly fewer repairs. Furthermore, the repair rate was less than the 3% forecast in the 2015 GRC.[282]

SCE's 2015 recorded adjusted expenses for its Poles activities were $18 million less than authorized in its 2015 GRC.[283]

FERC Sub-Account 566.125

ORA relied on SCE's initial September 2016 testimony when SCE gave its forecast of $685,000 for FERC sub-account 566.125 – Transmission Intrusive Pole Inspections and Transmission Pole Loading Program Assessments,[284] and $746,000 for Transmission Pole Loading Program Related Expense and Transmission Pole Loading Program Repairs.[285] As shown in ORA's testimony, submitted in April 2017, ORA agreed with this forecast.[286]

SCE's rebuttal testimony changed its forecast.[287] Having had no notice or opportunity to review this proposed increase, ORA opposes SCE's changed forecast for FERC sub-account 566.125, Transmission Intrusive Pole Inspections and Transmission Pole Loading Assessments.

FERC Sub-Account 583.125

SCE forecasts $34.799 million for Sub-Account 583.125 (Labor of $8.869 million and Non-Labor of $25.930 million) for its Distribution Intrusive Pole Inspections, Joint Pole Credits, Distribution Pole Loading Program Assessments and Joint Pole Organization expenses.[288]

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[281] Ex. SCE-2, Vol. 9, p. 17.

[282] Ex. SCE-2, Vol. 9, p. 3.

[283] Ex. SCE-2, Vol. 9, Figure I-1, p. 2. SCE's 2015 GRC request was $50 million and it was authorized $46 million for its Poles activities.

[284] Ex. SCE-2, Vol. 9, pp. 80-83; E.

[285] Ex. ORA-7, p. 20.

[286] Ex. ORA-7, p. 20.

[287] Ex. SCE-18, Vol. 9, p. 6, lines 10-15.

[288] Ex. SCE-2, Vol. 9, p. 82.

SCE's forecast of $34.799 million is an increase of $13.375 million or 62.43% over 2015 recorded adjusted expenses of $21.424 million. ORA forecasts $27.944 million using SCE's 2015 recorded adjusted expenses, 2016 recorded adjusted expenses, and SCE's TY 2018 forecast for SCE's Sub-Account 583.125. ORA's estimate is $6.855 million less than SCE's forecast.[289]

ORA does not oppose SCE's TY forecast for Distribution Intrusive Pole Inspections of $4.984 million[290] and Joint Pole Credits of $(3.140) million that are included in its forecast for Account 583.125.[291] ORA objects to SCE's forecast for Distribution Pole Loading Program Assessments of $24.407 million and its Joint Pole Organization expenses of $8.548 million.[292]

Distribution Pole Loading Program Assessments

For Distribution Pole Loading Program Assessments, ORA forecasts $18.658 million.[293] ORA's forecast uses a three-year average (2014-2016). If the Commission is disinclined to adopt ORA's forecast, then ORA suggests, as an alternative, that the Commission use a test year estimate of $11.355 million for SCE's Pole Loading Program Assessments. The estimate of $11.355 million is the difference between SCE's authorized funding in the 2015 GRC of $25.071 million[294] (combined transmission and distribution pole program assessment funding), and its recorded 2015 expenses of $13.716 million. ORA's alternative recommendation considers the amount recorded in SCE's two-way balancing account for pole loading program assessments.

SCE's TY forecast includes funding for the completion of "200,000 assessments in 2016, 220,000 in 2017 and 230,000 in 2018."[295] SCE's pole assessments are performed by contractors

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[289] Ex. ORA-7, p. 21.

[290] Ex. ORA-7, footnote 64: "SCE's recorded adjusted expenses for its Distribution Intrusive Pole Inspections declined by $2.116 million between 2013 and 2015 from $8.158 million to $6.042 million. SCE's 2015 expenses of $6.042 million are $1.367 million less than authorized in its 2015 GRC of $7.409 million (*See* Ex. ORA-7-WP, p. 7-9 – 7-14: SCE response to ORA Verbal-006, Q.1-a). SCE's TY forecast of $4.984 million is $1.058 million less than its 2015 recorded expenses. The decline in expenses is due to SCE's completion of its first ten-year cycle for its grid and non-grid pole inspections (*See,* Ex. SCE-2, Vol. 9, pp. 41-42)."

[291] Ex. ORA-7, p. 22.

[292] Ex. ORA-7, p. 23.

[293] Ex. ORA-7, p. 23.

[294] *See* Ex. ORA-7-WP, p. 7-1, SCE response to ORA-SCE-Verbal-006, Q.1.

[295] Ex. SCE-2, Vol. 9, p. 18. SCE proposes to continue the Pole Loading Program two-way balancing account in the TY but requests that the 15% cap above authorized expenditures that was adopted by the

and the majority of the expenses for this activity is recorded as non-labor. SCE states the "cost per assessment has stayed relatively constant throughout the recorded period and is expected to stay constant throughout the forecast period."[296] SCE's recorded adjusted expenses declined by $6.110 million between 2014 and 2015, and SCE recorded $12.255 million for 2015.[297]

SCE's Pole Loading Program began in January 2014, and its "forecast had called for 205,000 assessments per year for 7 years beginning in 2014."[298] SCE did not meet the assessment proposals it made in its 2015 GRC, and did not spend the funds it was authorized for pole assessments for the three-year period (2014-2016).[299]

In D.15-11-021, the Commission authorized SCE $22.323 million ($66.969 million over the three year rate case cycle) for Distribution Pole Loading Program Assessments.[300] In the three year period (2014, 2015 and 2016) SCE recorded Distribution Pole Loading Program Assessment expenses of $50.777 million[301] and the three year average (2014-2016) for the number of Distribution Pole Program Assessments completed is 144,717. The average over the three year period for total pole loading assessments completed (Transmission and Distribution) is 161,786 and the average cost for total pole assessments performed is $18.658 million.

D.15-11-021 adopted SCE's proposed seven-year assessment schedule, to begin in 2015, performing 205,754 pole assessments a year at $106 per pole. SCE's 2015 GRC O&M expense forecast also included funding for fourteen planners that were supposed to be dedicated to its Pole Loading Program.[302]

Commission in its 2015 GRC be removed. ORA's recommendation and discussion on SCE's two-way balancing account proposal is included in Ex. ORA-10.

[296] Ex. SCE-2, Vol. 9, p. 18.

[297] Ex. ORA-7, p. 24.

[298] Ex. SCE-2, Vol. 9, p. 17.

[299] Ex. ORA-7, p. 24.

[300] Ex. ORA-7, p. 25, footnote 75: SCE response to data request ORA-SCE-Verbal-006, Q.1 and D.15-11-021, p. 121. SCE was authorized $2.748 million for Account 566.125 - Transmission Pole Loading Program Assessments in its 2015 GRC and recorded 2015 expenses of $1.461 million and recorded 2016 expenses of $0.948 million.

[301] The three-year average (2104-2016) for the number of Distribution Pole Program Assessments completed in 144,717. The average over the three-year period for total pole loading assessments completed (Transmission and Distribution) is 161,786, and the average cost for total pole assessments performed is $18.658 million. (Ex. ORA-7, pp. 25-26.)

[302] D.15-11-021, pp. 121 through 123.

In this GRC, ORA asked SCE for documentation of the number of planners dedicated to SCE's Pole Loading Program, and was told SCE "subsequently … determined that the employees performing the work referenced in the question should charge capital."[303]

In Rebuttal, SCE says ORA's proposal is "inconsistent with the Commission's decision, D.15-11-021."[304] In support of this, SCE says that, "[i]n D.15-11-021, the Commission rejected ORA's proposal to lengthen the PLP Assessment program from seven to ten years." SCE goes on to say that, "[d]espite ORA's claims to the contrary, ORA's current proposal amounts to a restatement of its previous position."[305] SCE then discusses the Commission's interest in "quickly developing a more comprehensive understanding of the extent of overloaded poles outweighs the potential cost deferral advantage of slowing the pace of assessments."[306]

As noted in its testimony, ORA recognizes that, in the TY 2015 GRC decision, the Commission adopted SCE's proposed seven-year assessment schedule. According to SCE's schedule, SCE would perform 205,704 pole assessments a year beginning in 2015.[307] But SCE's own records show that in the years 2015 and 2016, it did not complete the number of Pole Assessments it said it would.[308]

Three years (2014-2016) of data on the number of pole assessments SCE completed and SCE's recorded costs is now available for review and analysis. ORA asks that the Commission consider SCE's actual performance against the claims SCE made in its last GRC when it considers SCE's claims in this GRC. ORA continues to recommend a forecast of $18.658 million as a reasonable expense level for SCE's TY Distribution Pole Loading Program Assessment expenses.[309]

Joint Pole Organization

For its Joint Pole Organization TY expenses, SCE forecasts $8.548 million. ORA forecasts $7.442 million using SCE's 2015 recorded adjusted expenses as a basis plus

[303] Ex. ORA-7-WP, p. 7-26.

[304] Ex. SCE-18, vol. 9, p. 7, heading, lines 6-7.

[305] Ex. SCE-18, Vol. 9, p. 7.

[306] Ex. SCE-18, Vol. 9, p. 7.

[307] Ex. ORA-7, p. 26.

[308] Ex. ORA-7, p. 25, Table 7-13, see also footnote 74.

[309] Ex. ORA-7, p. 27.

incremental funding of $0.553 million for proposed activities and staffing.[310] ORA normalized SCE's incremental request of $1.659 million over the three year rate cycle.[311]

Some of the activities performed by SCE's Joint Pole Organization are the same or similar to activities performed by other business units/line items within SCE's T&D organization recording expenses to FERC sub-accounts 566.125, 571.125, 583.125 and 593.125 (i.e., Transmission/Distribution Pole Loading Program Assessments, Transmission/Distribution Pole Loading Program Repairs, and Distribution Intrusive Pole Inspections). These programs already have costs embedded in rates.[312] As ORA said in its testimony, if SCE chooses to organize its business units/line items within its T&D organization so that different areas are performing the same or similar activities, then the duplicative cost should be funded by SCE shareholders, not its ratepayers.[313]

In Rebuttal, SCE objects to ORA's forecast saying that "ORA accepted SCE's need to add staff," but that "ORA's calculations are at odds with ORA's intent."[314] In Rebuttal, SCE also refers to the "…extensive documentation of the increased workload in JPO" SCE provided.[315]

The "extensive documentation of the increased workload in JPO" was apparently provided in a data request response to TURN, not ORA. The documents SCE cites in Rebuttal that it did provide ORA in support of this "increased workload" were SCE's direct testimony on

[310] Ex. ORA-7, p. 27.

[311] ORA calculated its estimate for SCE's Joint Pole Organization by using 2015 expenses of $6.889 million and adding incremental funding of $0.553 million ($1.659 million divided by three years = incremental funding of $0.553 million). Incremental funding of $4.977 million over the three year rate case is not necessary for SCE to address JPO proposed activities.

[312] Ex. ORA-7, p. 28, footnote 82: SCE's Account 566.125 and 583.125 records costs in its line item within those accounts for Pole Loading Program Assessments that are incurred by SCE's contractors and SCE employees performing pole loading assessments to determine a poles safety factor and performs field checks on various poles (Ex. SCE-2, Vol. 9, pp. 17-19). SCE records costs incurred for visual and intrusive pole inspections in line items included within Accounts 566.125 and 583.125 (Ex. SCE-2, Vol. 9, pp. 41-42). SCE's Account 571.125 and 593.125 records costs incurred by SCE's contractors and SCE employees performing pole loading program repairs. The pole loading repair activities include the design/drawing and installation or modification of guy wires. SCE's TY forecast for Accounts 571.125 and 593.125 for pole loading program drawings and repairs is based on "historical values" for those activities (Ex. SCE-2, Vol. 9, pp. 20-22).

[313] Ex. ORA-7, p. 30.

[314] Ex. SCE-18, vol. 9, p. 11.

[315] Ex. SCE-18, vol. 9, p. 12.

the subject (one paragraph and a table),[316] a reference to a workpaper (one page), and a data request response to ORA (six lines).[317]

ORA considered SCE's September 2016 testimony to be inadequate, and so ORA made its own forecast based on the facts available. SCE's June 2017 Rebuttal is too little too late to verify. ORA continues to recommend the Commission adopt ORA's estimate of $7.442 million as a reasonable TY estimate for SCE's Joint Pole Organization.

FERC Sub-Account 593.125

SCE forecasts $7.329 million for FERC sub-account 593.125 (Labor of $0.108 million and Non-Labor of $7.221 million) for its Distribution Pole Loading Program Capital Related and Distribution Pole Loading Program Repairs expenses.[318] SCE's forecast of $7.329 million is an increase of $3.337 million or 83.59% over 2015 recorded adjusted expenses of $3.992 million. ORA forecasts $4.584 million for SCE's Sub-Account 593.125. ORA's estimate is $2.745 million less than SCE's forecast.[319]

There are no historical expenses recorded in FERC sub-account 593.125 for 2011-2013 because SCE's Pole Loading Program did not start until January 2014. ORA does not oppose SCE's TY forecast for its line item for Distribution Pole Loading Program Capital-Related Expenses of $2.402 million.[320]

ORA does dispute SCE's forecast for Distribution Pole Loading Program Repairs. For Distribution Pole Loading Program Repairs, SCE forecasts $4.927 million for the test year. ORA forecasts $2.182 million using SCE's 2015 recorded adjusted expenses as a basis, plus incremental funding of $1.372 million. ORA normalized SCE's incremental request of $4.117 million over the three year rate cycle.[321]

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[316] Ex. SCE-2, vol. 9, pp. 70 &71.

[317] Ex. SCE-18, vol. 9, p. 11, lines 17-18 and Appendix p. B-11.

[318] Ex. SCE-2, Vol. 9, p. 83.

[319] Ex. ORA-7, p. 30.

[320] Ex. ORA-7, p. 31.

[321] Ex. ORA-7, p. 32, footnote 87: ORA calculated its estimate for SCE's Pole Loading Program Repairs by using 2015 recorded adjusted expenses of $0.810 million and adding incremental funding of $1.372 million ($4.117 million divided by three years = incremental funding of $1.372 million).

SCE's pole repairs are directly related to the number of pole loading assessments completed. SCE says that "[j]ust as the number of assessments ramped up over 2014, the number of repairs ramped up as well,"[322] and that SCE performed approximately 63,000 fewer pole assessments in 2015 than SCE had originally forecast in its 2015 GRC.[323]

In D.15-11-021, the Commission authorized SCE $8.817 million for Distribution Pole Loading Program Repairs.[324] SCE recorded $810,000[325] in 2015, $1.503 million in 2016.[326]

When ORA requested clarification on the number of pole loading program repairs SCE completed, SCE's response was that:

> SCE-02, Volume 9, page 20 provides a variance analysis for repairs, and explains that the lower count of repairs is linked to the slower ramp-up of assessments. As explained in that testimony, since repairs may be completed one or two years after the assessments, the increase in repairs lags behind the increase in assessments. The forecast rate of pole repairs relied upon for the 2015 GRC forecast was 3%, as indicated in SCE-03, Volume 6, Part 2 on page 22, and was based on the 2013 PLP Pole Loading Study (included in SCE-02, Volume 9, workpapers starting at page 89) as noted in that testimony. The 2018 GRC forecast for pole repairs, based on an updated version of SPIDCalc, is based on data from the first quarter of 2016, as indicated in workpapers page 134 in SCE-02, Volume 9.[327]

[322] Ex. SCE-2, Vol. 9, p. 20.

[323] Ex. SCE-2, Vol. 9, p. 3.

[324] Ex. ORA-7, p. 33, footnote 94: SCE's testimony says that, in 2015, it completed 2,711 repair designs and constructed 569 repairs (Ex. SCE-2, Vol. 9, p. 20). This statement conflicts with information provided in data response ORA-SCE-137-TLG, question 15. In the response, SCE states it completed 2,307 designs and constructed 480 repairs in 2015. (Ex. ORA-7-WP, p. 7-27.)

[325] Ex. ORA-7, p. 33, footnote 95: ORA-SCE-Verbal-006, Q.1 and D.15-11-021, p. 124. SCE was authorized $1.081 million for Account 571.125 - Transmission Pole Loading Program Repairs in its 2015 GRC and recorded 2015 expenses of $22,000. SCE recorded 2016 expenses of $21,000 for Transmission Pole Loading Program Repairs. SCE provided its 2016 recorded adjusted expenses for Transmission Pole Loading Program Repairs of $21,000 and Distribution Pole Loading Program Repairs of $1.503 million (Account 593.125) on March 20, 2017 (by e-mail).

[326] Ex. ORA-7, p. 33.

[327] Ex. ORA-7, pp. 33-34.

In its 2015 GRC, SCE estimated that 3% of its poles would need repairs. In the TY 2015 GRC, SCE forecast 2,100 repairs in 2014 and 5,700 poles per year beginning in 2015.[328]

Now, in this GRC, SCE says that "[t]he current repair rates for poles in high fire areas and non-high fire areas are 1.53% and 1.19%, respectively, which are rates based on the new version of SPIDACalc."[329]

SCE's Pole Loading Program is still in the early stages. SCE's proposed pole loading repairs and TY estimates for FERC sub-account 593.125 should be adjusted based on the three years of data (2014-2016) of SCE's completed pole loading assessments and pole repair and spending levels. SCE's 2016 recorded adjusted expenses for its Distribution Pole Loading Program Repairs were $1.503 million. The three year average (2014-2016) for SCE's Distribution Pole Loading Program Repairs is $788,000. ORA recommends the Commission adopt a forecast of $2.182 million as a reasonable expense level for SCE's TY 2018 Pole Loading Program Repairs.[330]

4.10 T&D Grid Modernization

In the testimony SCE filed with its Application in September 2016, SCE requested $637 million in capital in Test Year 2018[331] for new or expanded programs to improve the performance of its grid, and address SCE's concerns regarding integration of Distributed Energy Resources.[332][333] SCE subsequently revised its Grid Modernization estimate so that, at the close of hearings, the request is for approximately $539 million.[334]

SCE's request for Grid Modernization investments is premature, and ORA's testimony details eight reasons why SCE's Grid Modernization proposal should not be adopted now.[335]

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[328] D.15-11-021, p. 124.

[329] Ex. SCE-2, Vol. 9, p. 21.

[330] Ex. ORA-7, p. 35.

[331] Ex. SCE-1, p. 5, Figure II-1.

[332] Ex. ORA-9A (and Ex ORA-9), pp. 7 and 32-57.

[333] Ex. SCE-1, p. 5, Figure II-1.

[334] To ORA's knowledge, SCE has not provided an errata to Ex. SCE-1 from which ORA obtained the original total Grid Modernization cost of $637 million. Per Ex. SCE-18, Vol. 10, p. 6, Table I-2, SCE reduced its request for two Grid Modernization programs: distribution automation and subtransmission relays. For 2018, the adjustment is $637-$56.8-$41.6 = $538.6 million.

[335] Ex. ORA-9A, (and Ex.ORA-9), p. 2.

Based on these considerations, ORA proposes no capital or O&M funding for SCE's new Grid Modernization programs. ORA does recommend the Commission continue funding certain historical programs for the rate case period[336] and supports funding of circuit specific Distributed Energy Resource-related upgrades if they are properly justified.[337]

As discussed below, the Commission should not authorize new Grid Modernization programs for the following reasons: (1) SCE's Grid Modernization program costs are very high, with minimal corresponding benefits, so a showing of cost-effectiveness, as required by AB 327, has not been made; (2) tools and guidance from the Distributed Resource Plan proceeding are not incorporated; (3) SCE's Grid Modernization plan does not incorporate results from a multitude of related and ongoing ratepayer/ taxpayer funded Research, Development and Demonstration projects; (4) existing AMI[338] (SCE's SmartConnect) and forthcoming (smart inverters) resources are not adequately incorporated; (5) safety is not the primary justification for SCE's Grid Modernization requests; (6) ORA's support for ongoing Transmission and Distribution programs will allow SCE to maintain a reasonable level of reliability; (7) allocation of Grid Modernization costs between Distributed Energy Resources and reliability should be investigated further; and (8) funding from Distributed Energy Resources developers and owners should be considered in approving Grid Modernization investments.[339]

SCE's Grid Modernization High Program Costs

ORA's testimony describes the statutory requirement in AB 327 for cost effectiveness.[340] ORA's testimony refers also to the Grid Modernization workshop where CPUC Energy Division staff proposed a litmus test: "Will proposed Grid Modernization Investment realize net ratepayer benefits?"[341] SCE's initial showing provided limited cost-benefit forecasts, and failed to provide the information required to answer this critical question.

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[336] Ex. ORA-9A (and Ex. ORA-9), pp. 2-4.

[337] Ex. ORA-9A (and Ex. ORA 9), p. 57.

[338] Advanced Metering Infrastructure.

[339] Ex. ORA-9A (and Ex. ORA-9), pp. 32-57.

[340] Ex. ORA-9A, (and Ex. ORA-9) pp. 32-35.

[341] Ex. ORA-9-WP, Book 2 of 2, p. 373: CPUC staff presentation at DRP Grid Modernization Workshop held Jan. 24, 2017, slide 17.

One of the two attempts SCE made to show its Grid Modernization proposal was cost-effective was to show a payback period of less than five years for its updated Distribution Automation (DA) program.[342] While this analysis was not supported in SCE's testimony or workpapers, ORA was able to learn some details through discovery. After reviewing SCE's analysis, ORA provided the following findings/recommendations:[343]

- SCE's analysis considered only the first year of the Worst Circuit Replacement Distribution Automation program on the 200 least reliable circuits. Payback and cost-effectiveness declines each year as DA is applied to more reliable circuits,
- SCE's analysis did not include the cost of other Grid Modernization components required to achieve the purported reliability benefits, and
- A continuation of SCE's existing (+1+1) has a shorter payback than SCE's 3-3 proposal.[344]

SCE's rebuttal responded to ORA's testimony and concluded that "ORA's payback analyses are incorrect."[345] This statement incorrectly presumes that ORA's analysis was intended to show whether or not SCE's proposal was cost-effective. ORA's testimony explicitly stated that this was not the case.[346] SCE's rebuttal and its supporting workpaper entitled "Corrected ORA Payback Period Analysis" represent a new creation where the revised payback periods are driven by an expanded quantification of benefits based on SCE's Benefit to Cost Analysis. SCE rebuttal did correctly identify an error in ORA's testimony regarding the payback analysis. ORA's analysis describing a "1-1" Distribution Automation scheme should have been referred to as a "+1+1" proposal based on data showing that many of SCE's circuits targeted for WCR-DA already have one switch and one. ORA's errata testimony, Exhibit ORA-9A, corrected this labeling error and the comments that were based upon it.[347] ORA also corrected its main conclusion so that ORA's testimony now says that 79% of SAIDI[348] improvement, and

[342] The other was a discussion of SCE's proposed "deferral pilot projects." See ORA's critique of SCE's limited showing in Ex. ORA-9A, p. 34.

[343] Ex. ORA-9A, pp. 104-107.

[344] Ex. ORA-9A, pp. 110-111.

[345] Ex. SCE-18, Vol. 10, p. 43.

[346] Ex. ORA-9A, pp. 105-106.

[347] See Ex. ORA-9A, p. 107.

[348] System Average Interruption Duration Index.

76% of the SAIFI[349] improvement, can be achieved using a "+1+1" DA program.[350] The primary implication is unchanged: a more simplified program, originally a "1-1" Distribution Automation program, provides a vast majority of the purported benefits of SCE's more expensive "3-3" DA proposal. SCE's rebuttal also shows that a "+1+1" configuration has a shorter payback than its proposed "3-3" configuration.[351]

Other intervenors also issued discovery requests regarding GM cost effectiveness and SCE provided a Benefit to Cost analysis (BCA) in response to TURN.[352] SCE criticized intervenor testimony on the cost-effectiveness of SCE's Distribution Automation proposal.[353]

The bulk of SCE's rebuttal pertains to analysis performed in response to intervenor testimony of TURN and SEIA/VoteSolar. SCE did not, however, provide a cost-benefit analysis of its Substation Automation (SA-3) program. The omission is clear from SCE rebuttal testimony and relationship between SA-3, DA, and the other components of SCE's Grid Modernization proposal is illustrated in SCE's Figure I-1 in its rebuttal testimony.[354] ORA confirmed through discovery that SCE did not perform a Benefit to Cost Analysis for its SA-3 proposal.[355]

SCE's rebuttal challenges intervenor arguments favoring Distribution Automation schemes that maximize cost-effectiveness based on an assertion that there is a minimum amount of benefit that should be sought.[356] This threshold is "lifting SCE's reliability performance above the bottom half of utilities in the US." This is a goal set arbitrarily by SCE, [357] as discussed in more detail below in ORA's discussion of Support for Ongoing Programs and Reliability.

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[349] System Average Interruption Frequency Index.

[350] See Ex. ORA-9A, p. 110-111.

[351] Ex. SCE-18, Vol. 10A4, p. 45A4, Table II-5.

[352] Ex. TURN 26, Q.55 attachment.

[353] See Ex. SCE-18, Vol. 10, pp. 43-50.

[354] Figure I-1 is provided on page 12 of Ex. SCE-18, Vol. 10. Discussion of the GM components provided in SCE's BCA is provided on pages 30-31 of the same exhibit.

[355] See Ex. ORA-110, p. 24: SCE response to data request ORA-SCE-248-TCR, Q. 7.

[356] Ex. SCE-18, Vol. 10, p. 40-41.

[357] Ex. SCE-18, Vol 10, p. 41.

In addition, SCE implies that automation is the only means by which reliability can be improved, since 80% of its 600 Worst Circuit Replacement circuits already have 1-1 automation.[358] The fact that the Worst Circuit Replacement program has historically focused on replacing cable versus automation clearly indicates that other options exist. This is discussed in more detail in the Distribution Automation section below.

SCE's rebuttal also fails to address a fundamental shortcoming of using cost-benefit forecasts for decision making: the asymmetry of how costs and benefits are realized. While forecast costs are almost always realized fully and immediately through rate increases, the forecast benefits are typically delayed and may never materialize. ORA's testimony pointed to its analysis of SCE's AMI deployment to show this shortcoming.[359]

In addition, SCE's proposal includes more forecasting uncertainty because it requires three expensive circuits ties, versus one in the "+1+1" scheme. SCE has forecast a cost of $500,000 to run new poles, wires, and other equipment required to tie adjacent circuits in three locations.[360] This forecast assumes important details for the ties including distance between circuits, congestion and terrain along the tie path, and whether the new equipment is above or below ground. If the detailed design for specific Worst Circuit Replacement program reveals the cost of ties exceeds SCE's forecast, SCE will have two options: a) proceed with the project to provide full benefits at a higher cost or b) eliminate one or more ties to meet the forecast cost, but with reduced benefits. In either case, the actual Benefit to Cost ratio will be lower than forecast. This uncertainty is magnified by a factor of three in SCE's proposal because it applies to three ties versus only one in "+1+1" scheme.

As discussed above, SCE has failed to demonstrate the cost effectiveness of its proposed Grid Modernization Program. Moreover, cost–effectiveness determination for Grid Modernization proposals has been scoped for stakeholder discussion and is expected to be addressed in Track 3 of the Distributed Energy Resources proceeding (R.14-08-013).[361]

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[358] Ex. SCE-18, Vol 10, p. 40.

[359] Ex. ORA-9A, p. 41.

[360] Ex. ORA-9A, p. 99. See the Distribution Automation section below regarding the reduction in SCE's forecast for circuit ties which might impact this unit cost.

361 Ex. ORA-9A, p. 23. Cost effectiveness methodology questions were included in the CPUC Staff White Paper on Grid Modernization attached to the Assigned Commissioner Ruling filed May 16, 2017 in R. 14-08-013. See pages 28-33.

Therefore, it is premature to approve the Grid Modernization Program in this proceeding, when the elements for determining cost-effectiveness have yet to be determined.

Tools and Guidance from the Distribution Resources Plan (DRP) proceeding

ORA's testimony provides a detailed review of AB 327 and the Distribution Resources Plan proceeding.[362] The Distribution Resources Plan (DRP) proceeding now includes 3 Tracks which define the new DRP structure.[363] Track 1 is for Methodological Issues, Track 2 is for Demonstration and Pilot Projects and Track 3 is for Policy Issues.[364] All three of these tracks impact SCE's Grid Modernization request, Track 3 in particular.[365]

ORA's testimony describes in detail what the Commission is and will be considering in the various Tracks of the DRP proceeding. Although final results from each DRP Track could provide meaningful guidance regarding the current GRC request, these results will not be available in time to inform the current GRC process.[366]

SCE's Grid Modernization proposal prejudges the outcome of the DRP proceeding, and the studies/demonstration projects that are underway. In doing so, SCE creates significant risk to ratepayers that it will deploy a Grid Modernization system that will not meet the requirement of the DRP, and that work completed at ratepayer expense will be unnecessary, excessive or inconsistent with Commission directives.[367]

ORA's primary recommendation, therefore, is that SCE's Grid Modernization request be denied in light of the overlap between these proceedings. However, if the Commission does approve any portion of SCE's request in this proceeding, the Commission should direct SCE to track costs associated with this program in a memorandum account and seek recovery in a future GRC application.

ORA's recommendation is further reinforced in light of the issues that will likely be addressed in the pending DRP Track 3 decision relative to SCE's Grid Modernization request. After ORA submitted its testimony, Assigned Commissioner Rulings (ACRs) and attached staff

[362] Ex. ORA-9A (Ex. ORA-9), pp. 14-24.

[363] Ex. ORA-9A (and Ex. ORA-9), p. 17, lines17-24.

[364] Ex. ORA-9A (and Ex. ORA-9), p. 17, lines17-24.

[365] Ex. ORA-9A (and Ex. ORA-9), p. 17, lines 23-24.

[366] Ex. ORA-9A (and Ex. ORA-9), p. 24.

[367] Ex. ORA-9A, pp. 35-36. These risks and their implications are discussed on pages 36-38.

white papers issued in the DRP proceeding signal issues that will likely be resolved by the end of 2017, including the following:

- Track 1 – ICA,[368] LNBA,[369] and Demonstration Projects A and B
  - Assigned Commissioner Ruling requesting comments on ICA and LNBA issued April 19, 2017
  - Comments from parties served July 15, 2017
  - Assigned Commissioner Ruling long term refinements for ICA and LNBA issued June 7, 2017
  - ICA/LNBA working group began meeting on long term refinements July 7, 2017
  - Proposed Decision issued August 25, 2017 proposes statewide ICA rollout ten months after final decision issued
  - Status report on highest priority long term refinements issued August 31, 2017
- Track 2 – Demonstration Projects C, D, and E
  - Revised demonstration projects, including SCE's Demo E, were approved in D.17-06-012
- Track 3.1 - DER Growth Scenarios and Distribution Load Forecasting
  - Working group meetings initiated and completed- April 17 to May 24, 2017
  - IOUs revised Assumptions and Framework document submitted June 9, 2017
  - Comments from parties served July 3, 2017
  - Assigned Commissioner Ruling adopting requirements for 2017-2018 planning cycle and open issues to be resolved in Track 3 decision issued August 9, 2017
- Track 3.2 - Grid Modernization Framework
  - Assigned Commissioner Ruling with CPUC Energy Division staff proposal issued May 16, 2017
  - Comments and reply comments from parties served June 19 and 28, 2017 respectively
- Track 3.3 - Distribution Deferral Framework

[368] Integration Capacity Analysis.

[369] Locational Net Benefits Analysis.

- ALJ Ruling with CPUC Energy Division staff proposal issued June 30, 2017
- Comments and reply comments from parties served August 7 and 18, 2017 respectively.

SCE's rebuttal seeks to downplay the significance of the Distribution Resources Plan proceeding on its proposal, stating "some Intervenors are under the impression that the primary purpose of SCE's Grid Modernization program is to meet the goals of the Distribution Resources Plan proceeding and enable Distributed Energy Resources."[370] It certainly appeared from SCE's direct testimony that the purpose of SCE's Grid Modernization program is to meet the goals of the Distribution Resources Plan and enable Distributed Energy Resources. In fact, in SCE's direct testimony, SCE's Grid Modernization proposal referred to Distributed Energy Resources and the Distribution Resources Plan more times than SCE referred to reliability and safety combined.[371] Moreover, before SCE even filed this GRC Application, SCE voluntarily provided a detailed summary of its Grid Modernization proposal as part of its July 1, 2016 statutorily mandated Distribution Resources Plan filing.[372]

Then, in rebuttal, SCE changed its position. Now, SCE says that its Grid Modernization proposal is primarily reliability-driven[373] and is justified "regardless of the outcome of the Distribution Resources Plan (DRP) proceeding."[374]

In its rebuttal, SCE also provided explanations of why individual elements of its Grid Modernization proposal cannot wait for the Distribution Resources Plan proceeding to conclude.[375] ORA's testimony did not provide detailed evaluations of individual Grid Modernization elements, except for Distribution Automation as discussed below.

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[370] Ex. SCE-18, Vol. 10, p. 9.

[371] ORA performed a word search on Ex. SCE-2, Vol. 10 and found the following frequency of use: "DER": 195; "DRP": 43; "saf": 54, "relia": 139. "Saf" and "relia" were used in lieu of safety and reliability to include all versions of the words, e.g., "reliable," "reliability."

[372] Application of SCE (U338-E) for Approval of its Distribution Resources Plan filed July 1, 2015 in A.15-07-002, attachment, pp. 201-232. CPUC guidance did not require SCE to provide a Grid Management plan in this filing. See ACR dated February 6, 2015 in R.14-08-013, pp. 1-2. The Distribution Resources Plans submitted by SDG&E and PG&E did not include Grid Management proposals.

[373] Ex. SCE-18, Vol. 10, p. 9.

[374] Ex. SCE-18, Vol. 10, p. 2.

[375] Ex. SCE-18, Vol. 10, pp. 37-72.

ORA's recommendations do, however, provide for a CPUC finding of need based on the full record in this proceeding, but ORA recommends that SCE bear the risk of non-compliance with future direction from the Distribution Resources Plan proceeding through the use of a memorandum account. According to ORA's proposal, SCE would not receive funding in this rate case for "Grid Modernization" projects, but it would have the opportunity for ratepayer funding in subsequent rate cases based on a determination that its expenditures were reasonable.

SCE's Grid Modernization Plan and Related Ratepayer/Taxpayer-Funded Projects

ORA's opening testimony includes a non-comprehensive list of programs that include "Smart Grid" or Grid Modernization projects, and additional discussion of specific projects in three of these programs that relate to SCE's Grid Modernization request.[376] ORA's testimony also includes a list of projects provided by SCE as "related to Distributed Energy Resources' integration in SCE service territory" that partially overlaps with the project list compiled by ORA.[377] From this testimony, it is clear that SCE's Grid Modernization plan does not incorporate results from a multitude of related and ongoing ratepayer/taxpayer funded Research, Development and Demonstration projects. This is another reason that ratepayer funding for SCE's proposed Grid Modernization plan should be denied.[378]

In rebuttal, SCE claims that "SCE has conducted rigorous technology assessments, demonstration projects and pilots to assess the technologies we are planning to deploy."[379] SCE refers to a single completed project, the Irvine Smart Grid Demonstration (ISGD) project, to support this claim, while ignoring the full list of relevant projects, including projects for which SCE recently received or is currently seeking funding.[380]

SCE also refers to a report, cited by ORA, which states that reducing the development time cycle for new designs and related technology solutions is critical. From that, SCE argues that "ORA's position that SCE must complete all demonstration projects related to modernizing

[376] Ex. ORA-9A, pp. 24-30.

[377] Ex. ORA-9A, p. 40.

[378] Ex. ORA-9A, p. 57.

[379] Ex. SCE-18, Vol. 10, p. 17.

[380] For example, SCE's EPIC-funded Integrated Grid Project (IGP) and Preferred Resource Pilot (PRP). See Ex. ORA-9A, pp. 131-132. See also, Ex. ORA_9-WP, Book 2 (Witness Roberts), pp. 553-596.

the distribution grid before SCE can make any modernizing improvements flies in the face of this MTS recommendation."[381]

SCE's conclusion is incorrect. The Conceptual Grid Modernization Technology Deployment figure cited by ORA shows standard technology development lifecycle in which "utility system-wide deployment" is preceded by research, development, and demonstration.[382] ORA agrees that accelerating the Research, Development and Demonstration processes is desirable, but that does not change the concept that system-wide deployment follows RD&D, including incorporation of results from demonstration and pilot projects. SCE's request to perform relevant pilot and demonstration projects while deploying Grid Modernization systems statewide is not consistent with the cited technology development lifecycle.

ORA's position is supported by developments in the Distribution Resources Plan proceeding. The Commission's Energy Division staff White Paper on Grid Modernization incudes a dimension of "emerging vs. mature" when classifying investments for consideration of funding requests and solicited comments on this issue.[383] ORA does not presume the outcome of the Distribution Resources Plan proceeding on this issue, but based on the staff white paper, the issue of technology maturity should be an issue to be addressed in the pending DRP Track 3 decision.

Existing Advanced Metering Infrastructure and Forthcoming Resources

ORA's opening testimony describes how SCE's Grid Modernization proposal does not adequately analyze and incorporate Advanced Metering Infrastructure (AMI)/smart meters and smart inverters as alternatives to SCE's proposed DA/FAN/WAN/GMS proposal.[384] Regarding AMI/smart meters, ORA summarized SCE's "SmartConnect" AMI system and discussed how providing power and voltage at the termination of nearly every distribution circuit aids outage detection, voltage measurement, and support for detailed analyses of circuit loading.[385] TURN's

[381] Ex. SCE-18, Vol. 10, p. 18.

[382] Ex. ORA-9A, p. 38, Figure 9-5.

[383] CPUC staff White Paper on Grid Modernization attached to the Assigned Commissioner Ruling filed May 16, 2017 in R. 14-08-013, pp. 14-17.

[384] Ex. ORA-9A, pp. 41-44.

[385] Ex. ORA-9A, p. 41.

opening testimony also recommended increased use of smart meter data to aid DER integration.[386]

SCE's rebuttal cites to a 2015 "smart meter optimization initiative" and the need for "near-real time" grid visibility to support a claim that "existing data sources alone will not provide sufficient [distribution grid] visibility."[387] ORA performed additional discovery late in the proceeding and determined the following from data request responses SCE provided after hearings concluded:

- The smart meter initiative cited by SCE was an internal process facilitated by a consultant,[388]
- SCE has not issued requests for information (RFIs) or requests for proposals (RFPs) to the vendors of its SmartConnect AMI system regarding whether its AMI system can be upgraded to provide additional grid monitoring capacity,[389]
- SmartConnect meters currently notify operators of outages and can be used to help locate the source of the fault,[390]
- The vast majority of SmartConnect meters can detect reverse power flow, and the balance may be able to have this capability with a firmware update,[391] and
- SmartConnect meters do not currently have the ability to signal grid operators when customer voltage exceeds Rule 2 limits, but it is likely that this capability could be added by modifying the meters.[392]

Based on this information it is clear that SmartConnect meters currently provide valuable information to distribution grid operators, and that additional benefit could be provided with

[386] Ex. TURN-6, pp. 63-66.

[387] Ex. SCE-18, Vol. 10, pp. 34-35.

[388] Ex. ORA-110.

[389] See Ex. ORA-110.

[390] See Ex. ORA-110, p. 20: SCE response to data request ORA-SCE-248-TCR, Q.3. SCE notes that smart meters by themselves do not identify the fault location or the cause of the outage, but it is clear that smart meters provide a geographic pattern of customer outages that can help locate the fault based on SCE's knowledge of the location of its equipment.

[391] See Ex. ORA-110, p. 23: SCE response to data request ORA-SCE-248-TCR, Q.6.

[392] See Ex. ORA-110, p. 21-22: SCE response to data request ORA-SCE-248-TCR, Q.4 and Q.5. Voltage exceptions are currently being generated today for approximately 4.6 million meters, but this data is manually processed.

upgrades. ORA acknowledges that SCE's AMI system has slower response times and a temporal disadvantage compared to SCE's Grid Modernization proposal, but this must be weighed against the spatial advantage of having data at nearly every customer location.[393]

First, SCE compares the capabilities AMI can or could provide to its Grid Modernization proposal and the benefits SCE says that its proposal can provide. The potential use of AMI as a tool to facilitate Distribution Energy Resources integration should be evaluated by comparing its unique benefits to the incremental costs of achieving them.[394]

For example, ORA understands that real-time monitoring is desirable, and that near real-time monitoring is generally available for transmission grid assets.[395] However, distribution systems have historically functioned without real-time monitoring, and this should be the baseline from which Grid Modernization upgrades are considered. The need for real-time monitoring of the distribution grid and Distributed Energy Resources is a topic that ORA recommended be addressed in the pending Distributed Resources Plan, Track 3 decision.

ORA's 2012 case study of SCE's AMI system anticipated this situation when it recommended that the Commission "create an environment that fosters the development of new benefits from the sunk cost in AMI."[396] SCE's internal evaluation of AMI cannot take the place of an independent assessment of benefits, nor without input from smart meter experts on actual costs for upgrades. Vendors with a vested interest in promoting AMI benefits, including but not limited to Itron, are best suited to provide a comprehensive analysis.[397]

The record in this proceeding is also rich with discussion and evidence regarding the use of nascent smart inverter capabilities to facilitate Distributed Energy Resources integration.[398]

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[393] The Smart Connect system provides metering for approximately 5 million, or over 99%, of SCE customers. Approximately 16,900, or 0.33%, of SCE customers use a separate AMI system known as Real Time Energy Metering (RTEM). See Ex. ORA-9-WP, Book 1, pp. 92, 93 and 103.

[394] Since the AMI system is already in SCE's rate base, the incremental costs are only those additional costs to modify or upgrade the system.

[395] See Ex. ORA-9-WP, Book 1: SCE response to data request ORA-SCE-178-TCR, Q.3. The SCADA system has a latency of 4 seconds.

[396] "Case Study of Smart Meter System Deployment: Recommendations for Ensuring Ratepayer Benefits," dated March 2012, p. 48. Available at http://www.ora.ca.gov/general.aspx?id=1517.

[397] Itron is the primary vendor for SCE's SmartConnect system. 12 RT, p. 1707, Gooding/SCE.

[398] See Exhibits ORA-09A, pp. 42-44 and 122-123, SEIA-Vote Solar, pp. 48-51, TURN-06, pp. 63-64, SCE-18, Vol. 10, pp. 34-36.

Smart inverters are Distributed Energy Resources communication networks that are owned by solar photovoltaic system owners and aggregators rather than a sunk ratepayer cost. The financial impact on SCE is the same however: less rate base building opportunity. The CPUC should similarly exercise caution when evaluating if SCE's Grid Modernization proposal fully uses smart inverter capabilities. One important difference between smart inverters and AMI is that the formers includes capabilities to actively manage grid conditions through Volt/VAR and curtailment/scheduling functions in addition to the ability to increase grid visibility.[399] Therefore the potential benefit stream from smart inverters is even greater than for smart meters, and the Commission should explore that option.

ORA's recommendation for an independent analysis for AMI is based in part on the fact that there is no active proceeding in which the Commission is investigating incremental AMI capabilities and costs. In contrast, defining smart inverter functions, and how to use them, is under consideration in multiple active Commission proceedings.[400]

SCE's Claimed Safety Justification

The Commission initiated the Safety Model Assessment Proceeding (S-MAP) proceeding to ensure risk and safety were addressed in GRCs. As part of the S-MAP process, SED reviewed SCE's GRC application and issued a report on January 31, 2017.[401] SED's report includes a section on Grid Modernization which states "SED does not believe SCE has demonstrated that its Grid Modernization program rises to the same safety risk ranking as some of SCE's other programs."[402] The SED conclusion is that "although the Commission may find other reasons to provide some level of funding for Grid Modernization, at this time SED would not support these programs based solely on their purported contributions to improving safety."[403] ORA agrees.

[399] See Ex. ORA-9A, p. 43.

[400] For example, R.11-09-011 which initiated the Smart Inverter Working Group (SIWG) and R.17-07-007 which is the follow-on Rule 21 proceeding which includes smart inverters within its preliminary scope. See Order Instituting Rulemaking (R.) 17-07-007, pp. 8-9.

[401] See Section III.C.5.

[402] SED Report, p. 49.

[403] SED Report, p. 50.

SCE's rebuttal asserts that, "like reliability, safety is an important grid modernization benefit."[404] ORA agrees, and does not question that SCE's Grid Modernization proposal should decrease both direct safety hazards from equipment failures, and indirect safety impacts attributed to power outages. However, SCE's arguments regarding safety being a driver of its Grid Modernization proposal are even weaker than its arguments regarding reliability since SCE has not shown that its safety performance is sub-par. Nor does SCE attempt to show that its Grid Modernization proposal addresses high priority safety risks. SCE's rebuttal concludes that "without a doubt, safety is the primary justification for Grid Modernization."[405]

This is an unsupported assertion contradicted by the SED report.

Support for Ongoing T&D Programs and Reliability

SCE's opening testimony states that its Grid Modernization proposal will provide reliability benefits, and that these benefits are needed now and desired by its customers.[406] SCE's T&D testimony provides no citations to Commission decisions, orders or any other directives that require SCE to increase reliability.

ORA does not challenge SCE's assertion that its electrical customers generally value reliability, nor that SCE's proposed Grid Modernization system would increase reliability. ORA's does challenge SCE's claim that reliability is one of four foundational issues to be balanced in establishing SCE's proposed Grid Modernization program.[407] ORA did challenge whether increasing system-wide reliability provided sufficient justification for SCE's expensive Grid Modernization proposal.

In response to an ORA data request, SCE stated that the Distributed Resources Plan proceeding sets a goal to increase reliability. SCE also referenced AB 66 (Muratsuchi, 2013).[408] ORA's direct testimony shows otherwise. First, the Distributed Resources Plan proceeding is intended to carry out the mandates of AB 327, and AB 327 does not create a mandate for increasing reliability of the distribution system. AB 327 established the need for a "distribution

[404] Ex. SCE-18, Vol.10, p. 28.

[405] Ex. SCE-18, Vol.10, p. 29.

[406] Ex. SCE-2, Vol 10, pp. 5-7, 22.

[407] Ex. ORA-9A, p. 13.

[408] Ex. ORA-9-WP, Book 1, p. 225: SCE response to data request ORA-SCE-TCR-218, Q.3.

resources plan proposal to identify optimal locations for the deployment of distributed resources." One benefit of Distribution Energy Resources to be considered in the evaluation of optimal locations is "reliability benefits."[409] Enabling reliability benefits from Distribution Energy Resources is very different from increasing the reliability of the distribution grid.

SCE points to a 2015 ruling in the Distributed Resources Plan proceeding that includes the goal to "improve reliability in a cost efficient manner," but it is important to place this phrase in the overall context of the DRP proceeding.[410] As discussed above, AB 327 does not set a goal to improve or increase reliability, nor does the DRP OIR issued in 2014, the January 2016 scoping memo or the August or October 2016 ACRs.

While the Commission created a Track 3 to establish this goal, the scope of Sub-Track 1 (Forecasting) included "determining the DER growth scenarios and/or anticipated investments in the distribution system to maintain reliability."[411]

AB 66 (Muratsuchi, 2013) added section 2774.1 to the Public Utilities Code. Section 2774.1 sets out the requirement for annual reliability reports from defined "electrical corporations" or utilities.[412] The statute does not set reliability targets or goals. According to the statute, the intended use of the reliability reports is the following: "[t]he commission shall use the information contained in an electrical corporation's annual reliability report to require cost-effective remediation of reliability **deficiencies**…"[413]

AB 66 establishes a means and goal of increasing reliability in areas with deficiencies. While increased system reliability scores are a byproduct of these efforts, AB 66 does not dictate that increasing system-wide reliability is the end goal. ORA's interpretation of AB 66 is consistent with SCE's testimony in Exhibit SCE-2, Vol. 8 which explains how Public Utilities

[409] AB 327, section 769(b) and (c).

[410] Ex. ORA-9-WP, Book 1, p. 225: SCE response to data request ORA-SCE-TCR-218, Q.4, citing to the Feb. 6, 2015 ACR in R.10-08-013, p. 3.

[411] ACR dated August. 9, 2016, p. 4, emphasis added.

[412] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB66

[413] Public Utilities Code section 2774.1(b)(1), as added by AB 66, 2013, emphasis added.

Code section 2774.1 and the Commission decisions that followed "add another driver for SCE's Worst Circuit Rehabilitation (WCR) program," a program that ORA fully supports.[414]

SCE has a multitude of ratepayer-funded T&D programs that impact reliability, both historically and going forward. Any claim that SCE's reliability is sub-par and needs to be improved must take into account all the T&D programs that ratepayers are already funding to improve reliability. In total, ORA's TY 2018 forecast provides 103% of SCE's recorded capital expenditures for 2016 and 91% of SCE's TY 2018 forecast for "traditional programs to serve load or maintain safety and reliability."[415]

The final element of ORA's opening testimony regarding the need to improve reliability was a summary of a 2016 report by the CPUC Policy and Planning Division (PPD) that provides reliability statistics for California IOUs for 2006-2015.[416] Based on this report, which was provided by SCE through discovery,[417] ORA found:

PPD's report shows SCE provides reliable service compared to PG&E and SDG&E and that its reliability is increasing. Comparisons within California's large IOUs provide the best comparison because the systems operate within roughly the same range of physical environments, and within the same complex regulatory environment.[418]

As previously discussed, SCE's rebuttal emphasized the importance of reliability improvements as a driver of its GM request.

First, SCE states that, contrary to ORA's assertions, SCE's reliability is declining, and supports this with a graph showing SAIDI[419] excluding Major Event Days (MEDs) increased by approximately 13% from 2006-2016.[420] SCE's different conclusion is based on the inclusion of

[414] See Ex. ORA-8, Table 8-1a, p. which shows ORA made a minimal (>.1%) adjustment to the WCR program. Ex. SCE-2, Vol. 8, p. 3 summarizes how AB 66 led to R.14-12-014, which was closed by D.16-01-008.

[415] Ex. ORA-9A, p. 46. Note that would be the 91% value would increase to 94% if 2015 authorized expenditures for 4 kV programs were used rather than SCE's TY 2018 forecast nearly doubling expenditures for 4kV programs.

[416] Ex. SCE-109.

[417] Ex. SCE-109, PPD report was provided in response to ORA-DR-25-TCR, 25 Q8.

[418] Ex. ORA-9A, p. 49.

[419] System Average Interruption Duration Index.

[420] Ex. SCE-18, Vol. 10, p. 21, Figure I-3. The 13% value is based on a 2006 value of 97 and a 2016 value of 110. The trend line has approximately the same slope.

2016 data, exclusion of MEDs, and a focus on SAIDI only as opposed to all reliability metrics. SCE's 2016 Annual Reliability Report filed with the CPUC shows a similar trend for CAIDI,[421] but relatively flat trend for SAIFI, and declining trend in MAIFI.[422] SCE also reports all metrics including all outages which shows reliability is increasing based on all four metrics.[423] None of SCE's reliability data includes planned outages, only unplanned outages.[424] SCE argues that "it is inappropriate to include MEDs when determining a utilities reliability performance."[425] However, a white paper that lead to the current IEEE methodology for determining MEDs indicated that data including all outages has merit:[426] Appropriate decision-making can be performed on each set of indices.

Normalized indices [with Major Event Days removed] provide metrics that can, and should, be used for both internal and external goal setting. Unadjusted indices [including Major Event Day], when compared to the normalized indices, provide information about utility performance during major events."

Many perspectives could be considered when determining which reliability data is relevant, but the perspective of customers who fund upgrades and endure outages is the most important. ORA believes that customers do not care whether an outage is caused by planned SCE repair work, an unplanned transformer failure, or an El Nino storm – they only care about total outage impacts, such as how long the refrigerator is off and when the lights come back on. While SCE cannot control the weather and weather-related MEDs, it does control the systems and processes that guide how it reacts to these events. Therefore, it does have some level of control of the duration of outages attributable to MEDs. The value and relevance of reliability data including MEDs is reflected by the fact that SCE includes MED occurrences in its annual

[421] Customer Average Interruption Duration Index.

[422] Momentary Average Interruption Frequency Index. These trends are for 2007 to 2016. The final version of this report was not available to ORA until after hearings. A preliminary version was provided to ORA through discover and is included In Ex. ORA-107, pp. 88-93.

[423]Ex. ORA-107, p. 6, Table 2- Distribution Indicies (2007-2016). Trends for system indicies that include both transmission and distribution outages are similar, except that SAIFI appears to be flat.

[424] SCE response to data request ORA-SCE-245-TCR, Q.14, provided on page 16 of Ex. ORA-108. Note that SCE's 2016 reliability report provides separate data in Section 3 which includes planned outages for 2016 only which was not used by SCE or ORA.

[425] Ex. SCE-18, Vol. 10, p. 19.

[426] Ex. ORA-107, p. 25.

reports, and that SCE's reports on reliability to local communities includes MEDs.[427] In summary, SCE's claim that its reliability is declining is only a partial truth based on one set of data over a limited timeframe. Other relevant data, such as MEDs, shows that SCE's reliability is stable or improving.

SCE's second point in rebuttal is that customers are concerned with current levels of reliability.[428] SCE also states that "ORA concludes that SCE's customers are satisfied with their current level of electric service."[429]

This statement mischaracterizes ORA's testimony.[430] ORA did not take a position regarding customer satisfaction, or about the J.D. Power report provided by SCE.[431] The question, is not whether customers are satisfied with SCE's power quality and reliability, but rather whether customers should pay higher rates for unnecessary increased reliability as presented in SCE's Grid Modernizatiion proposal.

SCE attempts to address this question using data on its Summer Discount Program (SDP).[432] SCE's reference to this program is irrelevant. The Summer Discount Program refers to demand response programs that provide a financial incentive to customers if the participant customer allows SCE to cycle the customer's air conditioning during defined "events."[433] SCE provides no basis why the perception of a participant in this program regarding air conditioner performance can be extrapolated to represent all SCE customers regarding all types of reliability SCE purports to reduce with its Grid Modernization program. Further, SCE fails to show how a Summer Discount Program situation equates to increased reliability.[434] All SCE showed was that SCE customers in hot regions value air conditioning.

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[427] Ex. ORA-107, pp. 71-87, includes a data request response and a presentation on Santa Barbara District 5 that includes only reliability data "with no exclusions" or with MEDs.

[428] Ex. SCE-18, Vol. 10, p. 21.

[429] Ex. SCE-18, Vol. 10, p. 19.

[430] Ex. SCE-18, Vol. 10, p.19. Also see 11 RT, pp. 1508-1510, Tolentino/SCE.

[431] Ex. SCE-18, Vol. 10, pp. 22-23.

[432] Ex. SCE-18, Vol. 10, pp. 23-24.

[433] See Ex. ORA-107, pp. 1-10.

[434] Figure I-6 of SCE's rebuttal, Ex. SCE-18, Vol 10, p. 24, refers to customer attrition, which is when a customer exits the program. When a customer leaves SDP, they forego a financial payment, but they are not penalized. See Ex. ORA-107, pp. 1-10.

Third, SCE's reiterates its claim that AB 66 requires or in some way justifies SCE's proposal to increase system-wide reliability. As stated in ORA direct testimony, Public Utilities Code section 2774.1 requires reliability reporting, not any specific reliability goals or target.

Fourth, SCE states that it "must improve reliability to maintain adequate service."[435] This short section and the cited documents support the need for adequate reliability, not that SCE must improve reliability.

Fifth, SCE argues that only its Grid Modernization proposal will improve reliability "measurably."[436] SCE's rebuttal defines "measurably" as a reliability improvement sufficient to lift SCE from the 2nd quartile to the 3rd quartile of utility performance based on a 2015 IEEE survey.[437] In terms of justifying SCE's Grid Modernization ratepayer funding request, this argument has two major flaws.

The first flaw is that SCE has identified no regulatory or other requirement that establishes the transition from 2nd to 3rd quartile of a survey as a definition of adequate reliability.[438] SCE also confirmed this "milestone" is arbitrary in terms of customer perceptions.[439]

The second flaw is that SCE's assertion is based on a confidential study by the IEEE and even SCE does not know how it was scored.[440] SCE's rebuttal overlays the position of various proposals and its 2016 system-wide SAIDI on top of the IEEE results.[441] These values are not part of the IEEE survey. More importantly, SCE fails to acknowledge the difficulties in ensuring an apples to apples comparison of reliability data. Two important factors discussed previously are how each utility captures, records and reports outage data, and whether planned outages are included or not. The impact of these two factors is significant.

[435] Ex. SCE-18, Vol. 10, p. 25.

[436] Ex. SCE-18, Vol. 10, p. 26.

[437] Ex. SCE-18, Vol. 10, Figure I-7, p. 27.

[438] Ex. ORA-110.

[439] Ex. ORA-110.

[440] 11 RT 1530, Tolentino/SCE.

[441] Ex. SCE-18, Vol. 10, Figure I-7, p. 27.

When SCE switched to its new ODMS[442] system, its SAIDI score jumped by over 40% in a single year. SCE attributed this to the increased accuracy of the new ODMS and not indicative of changes in actual reliability."[443] If any utilities in the top two quartiles of the IEEE study used a ODMS system like SCE's, the results would be skewed such that SCE might already be in the 2nd quartile.

Similarly, SCE's 2016 reliability report shows that including planned outages more than doubled its SAIDI score with MEDs excluded.[444] If any utilities in the bottom two quartiles of the IEEE study included planned outages, the results would be skewed with the same result. In fact, the IEEE survey disclosed that "data [in the reliability survey] may not be directly comparable," and listed data collection system differences and types of outages reported as two of the reasons.[445] In hearings, SCE's witness acknowledged that SCE did not perform any review of the utility data in the IEEE survey to ensure the data was compatible.[446]

Finally, SCE claims that the CPUC has authorized IOUs to improve reliability in past GRCs, citing to PG&E's "Cornerstone" program without providing the proceeding or decision numbers.[447]

As the Commission doubtless knows, PG&E was in a very different situation, with much worse reliability than SCE.[448] In the end, the Commission provided only a fraction of PG&E's request.[449]

SCE's characterization of ORA's testimony as stating that reliability does not matter to SCE's customers is incorrect. In fact, ORA's continued position is that reliability is not a valid justification for SCE's Grid Modernization proposal for the following reasons:

- ORA agrees with most of SCE's requests that impact reliability,

[442] Outage Database Reliability Metrics.

[443] Ex. ORA-110.

[444] Ex. ORA-107, pp. 92-93. Data on page 92 includes only unplanned outages for 2016; page 93 adds planned outages. (241.33-109.98)/109.98 = 119%. With MEDs included, the increase is slightly less: 265.83/134.48= 98%.

[445] Ex. ORA-107, p. 33.

[446] 11 RT 1534, Tolentino/SCE.

[447] Ex. SCE-18, Vol. 10, p. 27.

[448] Ex. SCE-109, pp. 10-14.

[449] D.10-06-048, p. 2.

- SCE has not demonstrated that customers desire for increased reliability justifies this request,
- SCE has not demonstrated that its reliability is so bad as to require THIS investment NOW,
- Investments to support state DER policies will likely require substantial investments in the future; ratepayer tolerance for rate increases should not be destroyed with this excessive request.
- Other parties have provided proposals that provide more cost-effective solutions.

Allocation of Grid Modernization Costs Between DER and Reliability

ORA's opening testimony raised the issue of allocating Grid Modernization costs to drivers such as safety and reliability, Distributed Energy Resources integration, and load growth. Parsing Grid Modernization costs between those costs that are driven by Distributed Energy Resources, and those that are not, is relevant to determining the reasonableness of specific Grid Modernization requests in the current case because there is clear legislative and regulatory support for the former, but not for the latter. This segregation of cost data will be even more important in subsequent cases, such as rate design and development of new net energy metering (NEM) rules, since cost-causation is an important consideration when determining which customers bear the brunt of rate increases.[450]

ORA constructed a table based on SCE data responses that allocates each Grid Modernization program/project expenditure request to six drivers including a "catch-all" "other" category.[451]

In rebuttal, SCE included a figure that allocated each Grid Modernization program/project to safety/reliability and Distributed Energy Resources integration on a percentage basis. The allocation was later adjusted in SCE errata.[452] This shows that SCE is

[450] D.16-010-44, Ordering Paragraph 12, p. 122, states that "The Director of Energy Division is authorized to take appropriate steps… to prepare for the Commission's review of the NEM successor tariff anticipated to be undertaken in 2019."

[451] Ex ORA-9A, p. 54, Table 9-2.

[452] Ex. SCE-18, Vol. 10, Figure I-2, p. 14. The allocation for Substation Automation was revised in SCE's fourth SCE errata 70/30 to 15/85 where the first number refers to safety and reliability and the second number to DER integration. SCE's figure I-2 does not include numerous programs in SCE's System Planning Testimony (Ex. SCE-2, Vol. 3) that SCE indicated enabled DER. See Ex. ORA-9, p. 55, Table 9-2, lines 2-5.

able to attribute individual programs and projects to these key drivers, and that these allocations are accurate enough to require revision.

Soon after SCE issued rebuttal, parties filed comments and reply comments regarding the Commission's Energy Division staff white paper on Grid Modernization in the Distribution Resources Plan proceeding.[453] These comments were extensive and encompassed a wide range of positions regarding whether or not cost allocation should factor into the definition of Distributed Energy Resources related Grid Modernization and the reasonableness review of SCE's request. ORA does not attempt to summarize them here, but instead reiterates its recommendation to wait for the disposition of this issue in the upcoming Distribution Resources Plan, Track 3 decision.

Funding from DER Developers and DER Owners for Grid Modernization Investments

Customers are generally required to pay a portion of grid upgrades they cause through increased load, and to extend the grid to new customers.[454] Similarly, developers of large distributed generators (developers) are generally required to pay a portion of grid upgrade costs the utility determines to be required to accommodate their energy.

SCE's testimony does not discuss these customer/developer contributions, which raises two concerns. First, it is not clear whether SCE has reduced its Grid Modernization requests to account for forecast customer/developer contributions. If SCE has not done so, its requests for cost recovery through rates would be excessive. Second, given the lack of discussion of customer/developer contributions, one could infer that SCE seeks to fully recover Grid Modernization investments through increased customer rates, rather than recover some costs directly from customers/developers.

ORA's direct testimony recommended that this issue, including the risks associated with the pending changes to existing exemptions for NEM and Electric Vehicles (EV), be addressed through DRP Track 3 prior to authorization of any Grid Modernization expenditures.[455] TURN's opening testimony discusses impacts of retail versus wholesale DER including a statement that

[453] Comments were filed June 19, 2017 and reply comments filed June 28, 2017 in R.14-08-013. The white paper was filed May 16, 2017 in the same docket.

[454] Details and exceptions are provided in Ex. ORA-9A, pp. 55-56.

[455] Ex. ORA-9A, pp. 55-56.

"large wholesale DERs contribute the greatest proportion of DER-related reliability challenges on the circuits to which they connect."[456]

SCE does not directly rebut either TURN's or ORA's testimony on the impacts of different types of DER and who should pay for them. ORA's original recommendation remains unchanged.

Distribution Automation

SCE proposes to expand its existing Distribution Automation program to install a more expensive "3-3" configuration on 863 circuits during the rate case period. The same equipment would be installed on 600 circuits based on reliability, and 263 circuits based on Distributed Energy Resources.[457]

ORA's direct testimony provides a general overview of SCE's request including a historical perspective on SCE Distribution Automation programs in terms of scope and cost;[458] a critique of the Worst Circuit Replacement portion of the DA program based on the proposed scope increase and purported justification;[459] and an evaluation of the Distributed Energy Resources portion of the program.[460] ORA finds the following based on its analysis:

- SCE has been automating distribution circuits since 1993,[461]
- SCE's proposed pace of 288 circuits per year is more than double the average number of circuits SCE automated from 2011-2015,[462]
- The proposed scope of DA equipment added to each circuit is greatly increased,[463]
- Previous unit costs indicate underground circuits were twice as expensive, but SCE's current proposal does not explicitly use this distinction,[464]

[456] Ex. TURN-06, p. 53.

[457] Ex. SCE-2, Vol. 10, p. 42 Table III-7 and Ex. ORA-9A, pp. 97-98.

[458] Ex. ORA-9A, pp. 94-100.

[459] Ex. ORA-9A, pp. 101-108.

[460] Ex. ORA-9A, pp. 108-116.

[461] Ex. ORA-9A, pp. 94-95.

[462] Ex. ORA-9A, p. 97.

[463] Ex. ORA-9A, p. 98.

[464] Ex. ORA-9A, p. 99. As shown in Table 9-9 on page 98, SCE uses an assumption of overhead to underground circuits to develop a single unit cost it applies to all circuits.

- The proposed unit costs are 20 times higher than previous unit costs,[465]
- Circuits selected based on Worst Circuit Replacement have a slightly lower unit cost than those selected based on Distributed Energy Resources,[466]
- Circuit ties represent the largest component of the proposed unit cost,[467]
- The proposed increase in the pace of Distribution Automation for Worst Circuit Replacement program circuits is not consistent with the relatively stable level of expenditures for the main Worst Circuit Replacement program,[468]
- SCE's Worst Circuit Replacement Program – Distribution Automation program is not justified by Distributed Energy Resources related benefits,[469]
- SCE's support for the Worst Circuit Replacement/ Distribution Automation program based on payback period is flawed,[470]
- Results from the Burbank Power and Water Distribution Automation program are not relevant to SCE's proposal based on the information provided by SCE,[471]
- Applying the 3-3 Distribution Automation scheme on the 263 circuits selected based on Distributed Energy Resources have reliability benefits approximately 10 times lower that Worst Circuit Replacement circuits[472]
- The 126 circuits included based on SCE's estimate of DER benefits use a simplistic internal tool rather than the Locational Net Benefits Analysis tool being developed in the DRP proceeding,[473]
- 74 circuits are proposed based on approval of SCE's Distribution Project Deferral Pilot, which ORA opposes,[474]

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[465] Ex. ORA-9A, pp. 99-100. SCE's forecast for DA was reduced in rebuttal as discussed below.

[466] Ex. ORA-9A, p. 99.

[467] Ex. ORA-9A, p. 100, Table 9-10. SCE's forecast for DA was reduced in rebuttal based on circuit ties costs as discussed below. It is not clear from SCE's testimony whether this results in the unit cost for circuit ties being less than those for RISs.

[468] Ex. ORA-9A, pp. 102-103.

[469] Ex. ORA-9A, p. 103.

[470] Ex. ORA-9A, pp. 104-107.

[471] Ex. ORA-9A, pp. 107-108.

[472] Ex. ORA-9A, p. 109.

[473] Ex. ORA-9A, pp. 109-111.

- 63 circuits are proposed based on SCE's forecast of Distributed Energy Resources growth on individual circuits, even though there are significant challenges in generating accurate DER forecasts at this level of granularity,[475] and
- 17 of the 63 circuits included based on forecast Distributed Energy Resources growth will only have 10% growth or less.[476]

Based on these findings, ORA recommends the Commission continue funding for DA at historical levels. ORA's TY 2018 forecast is $7.227 million compared to SCE's forecast of $278.9 million.[477]

SCE criticized ORA for rejecting SCE's Grid Modernization projects on policy grounds rather than "considering each request on its merits."[478] While this statement is generally true, the information above shows that it is inaccurate with respect to Distribution Automation.

Beyond this general criticism, SCE made two arguments regarding ORA's DA analysis. First, as discussed above, SCE asserted that ORA's testimony regarding SCE's payback analysis was "incorrect."[479] As ORA has already explained, SCE's assertion is without merit.

Second, SCE criticized ORA's analysis of the pace of SCE's Distribution Automation proposal.[480] This first part of this critique regarding the 2015 goal was accurate and ORA corrected this mistake in its errata. The second part of this rebuttal relates to how the proposed Worst Circuit Replacement Program driven Distribution Automation work compares to the main WCR program in SCE's Infrastructure Replacement volume.[481] SCE's testimony clearly shows

[474] Ex. ORA-9A, p. 112.

[475] Ex. ORA-9A, pp. 112-113. See joint utility Revised Distributed Energy Resource Assumptions and Framework Document filed June 9, 2017 in R.14-08-013, attachment, p. 32.

[476] Ex. ORA-9A, p. 113.

[477] Ex. ORA-9A, p. 114.

[478] Ex. SCE-18, Vol 10, p. 7.

[479] Ex. SCE-18, Vol. 10, pp. 43-45.

[480] Ex. SCE-18, Vol. 10, pp. 50-51.

[481] Ex. SCE-2, Vol. 8, pp. 13-27.

a forecast that is roughly equal to the last four years of recorded expenditures.[482] Therefore the proportion of Worst Circuit Replacement - driven Distribution Automation compared to that main program would increase from less than 5% to more than 140% in 2018.[483] This is a fundamental shift in how SCE proposes to improve the reliability of Worst Circuit Replacement circuits, away from cable replacement and towards automation. SCE did not provide an analysis to show Distribution Automation is the more cost-effective solution.

SCE's rebuttal also included a reduction to its Distribution Automation forecast. For example, SCE reduced its TY 2018 forecast from $278.9 million to $228.3 million for a 18.1% reduction.[484] The derivation of this reduction is not provided in SCE's rebuttal so it is not clear how SCE arrived at this reduction.[485] Even with the reduced forecast, Worst Circuit Replacement driven Distribution Automation Distribution Automation would represent over 116% compared to that main Worst Circuit Replacement program in 2018.[486] SCE's reduced forecast does not change the unsupported shift in its overall efforts to improve the performance of Worst Circuit Replacement circuits.

SCE's rebuttal does not change ORA's findings as summarized below, nor ORA's recommendations to support Distribution Automation at historical funding levels:[487]

- SCE's proposed increase in the Worst Circuit Replacement program circuits automated per year is neither justified nor consistent with the proposed pace of the Worst Circuit Replacement program generally,

[482] See Ex. SCE-2, Vol. 8, p. 18, Figure III-6. The average of 2013 to 2016 as shown is $132.4 million. As shown in Ex. ORA-8, p. 6, Table 8-1, 2016 actual expenditures were $143.162 million compared to a forecast of $137.827 million. Using 2016 recorded vs. forecast increases the average to $133.8 million.

[483] $5.9 million/$121.0 million = 4.87% in 2013. $181.5 million/126.2 million = 144%. Main WCR program data from Ex. ORA-8, p. 6, Table 8-1, line 1. WCR-DA data from Ex. ORA-9A, p. 96, Figure 9-17 and Ex. SCE-18, Vol 10, p.6, Table I-2, upper section.

[484] Ex. SCE-18, Vol. 10, p. 6, Table I-2.

[485] On page 5 of Ex. SCE-18, Vol. 10, SCE describes "an updated analysis for circuit tie upgrades," but the workpaper provided refers to non-tie unit costs. Refer to Ex. ORA-9A, p.100 for a breakdown Circuit Tie vs. non-tie unit costs used in SCE's initial testimony. SCE's rebuttal (SCE-18, Vol.10, p. A-2) shows a reduction in non-tie costs from $380.3 to $374.2 for WCR circuits in 2018. This 1.6% reduction in only a portion of the DA unit cost does not support the overall 18.1% reduction.

[486] $228.3 million/$126.2 million = 116%. Main WCR program data from Ex. ORA-8, p. 6, Table 8-1, line 1. WCR-DA data from Ex. SCE-18, Vol 10, p. 6, Table I-2, lower section.

[486] Ex. SCE-18, Vol. 10, p. 6, Table I-2.

[487] Ex. ORA-9A, p. 114.

- The benefits from proposed new "3-3" Distribution Automation are limited, particularly given the nearly 20 times increase in unit costs compared to the historical "1-1" Distribution Automation program,
- SCE's claim that the new Distribution Automation program will pay for itself in less than five years does not account for the full cost of required hardware, nor the reduction of benefits as the program progresses; a more complete payback analysis results in significantly longer payback periods,
- Automation of 126 DER circuits is based on estimation of Distributed Energy Resources benefits that should be informed by the ICA and LNBA tools being developed in the DRP proceeding,
- Automation of 74 Distributed Energy Resources circuits is based SCE's proposed Deferral Pilot, which ORA does not support, and
- Automation of 63 Distributed Energy Resources circuits based on forecast PV growth depends on PV and load forecasts, which should be informed by the DRP Track 3 process, and the ICA tool which is being developed in Track 1.

Field Area Network

Regarding the Field Area Network (FAN) ORA expressed four concerns that it considers should be discussed in Track 3 of the Distribution Resources Plan proceeding: (1) the need for real-time data; (2) decommissioning of the AMI system; (3) the bandwidth required based on the number of field devices installed; and (4) the requirement for a separate network to communicate with DER via smart inverters.[488]

Intervenor testimony and SCE rebuttal discussed each Grid Management component in detail and additional exploration continued during hearings. ORA's showing in this case is more than sufficient to support a finding that SCE's Grid Modernization request is premature and that Grid Modernization funding should not exceed historical levels. If however the Commission disagrees with ORA, evidence provided by TURN and SEIA/VoteSolar supports a less expensive means of integrating Distributed Energy Resources while maintaining reliability and safety.

4.11 T&D Grid Technology

SCE's direct testimony on Grid Technology includes a number of projects and activities that SCE divides into three general areas: Energy Storage Pilots, Advanced Technology

[488] Ex. ORA-9A, pp. 115-116.

Laboratories and Grid Integration activities.[489] All the programs SCE presents in the Grid Technology part of its direct testimony are exclusively CPUC jurisdictional. SCE's requests, and ORA's recommendations are discussed below.

4.11.1 Energy Storage Pilots

SCE seeks $68.583 million in ratepayer funding for its Energy Storage Pilots.[490] The Commission should deny SCE's Energy Storage Pilot request.[491]

SCE's Energy Storage Pilot request for funding in this rate case violates the Commission's explicit order in the Electric Program Investment Charge (EPIC) decisions that prohibits utilities from making research and development (R&D), and technology demonstration and deployment (TD&D) proposals in GRCs.[492] Despite SCE's claims to the contrary, SCE's own public statements show the Energy Storage Pilot to be a "demonstration project" that should not be presented for ratepayer funding in a GRC. Moreover, SCE's proposed Energy Storage Pilot is unnecessarily duplicative of other efforts in this area. And, finally, SCE's attempt to obtain Commission approval for its Energy Storage Pilot in this GRC fails to meet the strict standards of review for utility owned storage systems. For the following reasons, SCE has failed to meet its burden to show that all aspects of its proposal are reasonable.[493]

- **The EPIC Program (Electric Program Investment Charge)**

In 2012, the Commission designated the Electric Program Investment Charge (EPIC) as the principal forum for utilities to propose TD&D[494] projects, such as the Energy Storage Pilot. Specifically, in D.12-05-037, the Commission stated the utilities "shall no longer include

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[489] Ex. SCE-2, Vol. 11, p. 1. ORA presents its discussion of Grid Technology issues in an order intended to conform to the Common Briefing Outline.

[490] Ex. ORA-9, p. 124:3.

[491] Ex. ORA-9, p. 135:11-13. ["ORA recommends 2016 Energy Storage Pilot expenditures at 2016 recorded values of $678,000, per Section III.A.2, and zero expenditures for 2017 and 2018 as discussed above."]

[492] D.12-05-037, Investment Charge and Establishing Funding Collections for 2013-2020, Ordering Paragraph (OP) 17, p. 106; in R.11-10-003.

[493] D.06-05-016, p. 7; in A.04-12-014. ["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. Intervenors do not have the burden of proving the unreasonableness of SCE's showing."]

[494] D.12-05-037, Ordering Paragraph (OP) 5, p. 100. The Commission restricted SCE's funding to technology demonstration and deployment (TD&D). TD&D is the term the Commission uses in its EPIC program to specify the demonstration portion of research, development and demonstration (RD&D).

technology demonstration and deployment [TD&D] expenditures in their general rate cases (GRCs) unless specifically directed by the Commission to do so in a proceeding related to the Electric Program Investment Charge [EPIC]."[495] The Commission directed SCE, along with the other utilities, to file triennial investment plan applications to coordinate their investments in clean energy technologies and approaches,[496] and to demonstrate the potential for electricity ratepayer benefits.[497] To the extent opportunities emerge in between triennial investment plan cycles, the utilities are to file standalone applications accompanied by a showing that the request(s) meets EPIC's objectives and metrics.[498]

SCE has not followed these orders with respect to its proposed Energy Storage Pilot. Instead, SCE argues that its Energy Storage Pilot is not a demonstration project at all. This argument ignores the fact that the Commission already determined that end- use-cases, such as those SCE proposed to conduct through its Energy Storage Pilot (i.e., distribution deferral, integration of renewable resources, microgrids, etc.), are demonstration projects when it ordered the utilities to execute these use-cases as part of their Distribution Resource Plan (DRP) Demonstration Projects.[499] This is further evidenced by the fact that the Commission explicitly authorized PG&E's request to procure a battery energy storage system to execute a distribution deferral project with EPIC funds, as discussed in more detail below.

SCE claims that it is prohibited from executing its proposed Energy Storage Pilot projects through the EPIC program because the EPIC Program decision does not permit the use of EPIC funds to purchase commercially available technologies.[500] According to SCE, "the ES [Energy Storage] Pilots are based on commercially-available energy storage technologies, which is

[495] D.12-05-037, OP 17, p. 106.

[496] D.12-05-037, Finding of Fact (FOF) 9, p. 91.

[497] *See*, D.13-11-025, pp. 5, 11; in A.12-11-001 et al.

[498] D.12-05-037, OP 17, p. 106.

[499] *See*, D.17-02-007, pp. 2-3; in R.14-08-013. ["The February 6, 2015 *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resources Planning* (Guidance Ruling) directed the utilities to proposed DER-focused demonstration projects, and provided more detailed guidance regarding what should be included in those demonstration project."]

[500] Ex. SCE-18, Vol. 11, p. 12:19-21.

inconsistent with the definition of an EPIC TD&D [technology demonstration and deployment] project."[501]

SCE has incorrectly characterized the Commission's definition of an EPIC TD&D project. The Commission did not confine its definition to "pre-commercial" technologies. In fact, the Commission has approved commercially available energy storage projects in its EPIC triennial investment plan decisions.

D.12-05-037 did not narrowly define EPIC TD&D projects, as SCE alleges, to focus solely on funding "pre-commercial technologies." Rather, D.12-05-037 adopted a more expansive definition to allow the utilities to demonstrate and test new strategies.[502] The Commission defined EPIC TD&D as the "installation and operation of pre-commercial technologies *or strategies* at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks."[503] More specifically, the Commission reasoned:

> [W]e find that there is an important role for utilities both in technology demonstration as well as deployment. By deployment, we mean installations that are directly interconnected or located on the electricity grid of the IOUs. Deployment may also include strategies and other activities that are not specifically about the deployment of a technology itself, but are designed to test successful ways of encouraging customer adoption of clean energy technologies, such as electric vehicles, energy efficiency, or renewable generation, for example.[504]

The Commission clarified that it considered the utilities to be consumers, stating "[the utilities] also may ultimately become the consumer of technologies or processes that are designed to improve utility systems, so it will behoove them to invest in and test some new ideas."[505]

SCE's own testimony says that that the purpose of the Energy Storage Pilot is to "test" new applications for energy storage such as distribution reliability, integration of renewable

[501] Ex. SCE-18, Vol. 11, p. 13:2-3.

[502] D.12-05-037, p. 27; in R.11-10-003.

[503] D.12-05-037, p. 100, Ordering Paragraph 3(b).

[504] D.12-05-037, p. 40.

[505] D.12-05-037, p. 27.

resources, and grid optimization.[506] Testing new applications and/strategies for commercially available technologies is not lost to a regulatory grey area, but rather falls squarely within the objectives for which the Commission established the EPIC Program. As such, D.12-05-037 did not limit the execution of EPIC TD&D projects to pre-commercial technologies. Instead, it directed the utilities to use their EPIC TD&D funds on projects that test new strategies and applications: the alleged purpose of SCE's proposed Energy Storage Pilots. Nowhere in the EPIC decisions did the Commission preclude the utilities from purchasing commercially available products to execute EPIC projects.

To the contrary, in D.13-11-025, the 2012-2014 EPIC Triennial Investment Plans decision, the Commission explicitly authorized EPIC projects that requested the procurement of energy storage devices.[507] Specifically, the Commission authorized PG&E EPIC Project 1.02, Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction (also referred to as "Energy Storage for Distribution Operations"). There, the Commission concluded "[i]t is reasonable to allow PG&E to pursue energy storage research and demonstration with the goal of providing valuable experience for specific applications prior to a more widespread deployment in the future."[508]

Accordingly, PG&E purchased a turn-key, commercially available 500kW/4 hour lithium-ion battery energy storage system (BESS) to "[d]emonstrate the ability of a utility operated energy storage asset to address capacity overloads on the distribution system and improve reliability."[509] PG&E EPIC Project 1.02 is also intended to "[i]dentify an economic modeling tool to compare the planned traditional utility [upgrade] with alternatives using

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[506] Ex. SCE-2, Vol. 11, pp. 36, 39-41. [e.g., (1) "We developed the DESI Pilot Program to test the ability of a Battery Energy Storage System (BESS) to provide feeder load relief, give voltage support, and smooth the delivery of energy from renewable distributed generation to the grid." (2) "SCE will pilot energy storage systems to test the feasibility of optimizing the grid through contribution to distribution reliability and to evaluate whether energy storage can contribute to grid needs." (3) SCE will test whether energy storage can mitigate some of these issues by: [] *charging* when the generation on the circuit capacity; and [] *discharging* when the load is greater than the generation, or when capacity is available." (4) To test grid resiliency, SCE will seek to support customers with critical loads in remote areas where utility controlled storage may provide increased operating characteristics with a remote region."]

[507] D.13-11-025, pp. 26-27, 33-34; in A.12-11-004 et al.

[508] D.13-11-025, Conclusion of Law (COL) 16, p. 118.

[509] Ex. ORA-09-WP (Witness Myers), pp. 72-73.

distributed resources or demand-side investments" and to "[d]emonstrate peak saving use case along with other site-specific use cases as suggested by distribution operators."[510]

Here, SCE proposes to procure at least three utility-owned, commercially available battery energy storage systems as part of its Energy Storage Pilot projects to test the same energy storage use-cases (i.e., distribution reliability) that PG&E's EPIC Project 1.02 is authorized to test.[511] In fact, PG&E's EPIC Project 1.02 is an EPIC-funded demonstration project and SCE's proposed Energy Storage Pilot duplicates it.[512] SCE did not refute ORA's testimony on this point.

Similarly, in D.13-11-025, the Commission authorized SCE's EPIC Project 6.1.2, Demonstrate Grid-Scale Storage Strategies and Technologies (later renamed the Distributed Optimized Storage project or "DOS"). D.13-11-025 found that "SCE Proposal 6.1.2 is an energy storage project"[513] and that "SCE Proposal 6.1.2 is appropriate for EPIC funding and should be approved."[514]

In its 2016 EPIC annual report, SCE states that Project 6.1.2 "will demonstrate end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a *turn-key* solution that can cost-effectively be considered for SCE's distribution system."[515] As a turn-key project, SCE EPIC Project 6.2.1 necessarily requires the procurement of a utility-owned, commercially available energy storage system.[516] In fact, ORA identified SCE EPIC Project 6.1.2 (DOS) as an EPIC-funded demonstration project and stated SCE's proposed Energy Storage Pilots duplicates it. SCE does not refute ORA's testimony.

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[510] Ex. ORA-09-WP (Witness Myers), p. 72.

[511] Ex. SCE-02, Vol. 11, p. 39. ["SCE will pilot energy storage systems to test the feasibility of optimizing the grid through contribution to distribution reliability and to evaluate whether energy storage can contribute to grid needs. These pilot projects will use BESS as a tool to assess how energy storage can help mitigate distribution substation planning criteria violations, such as planned loading limit and duct-bank temperature violations."] The three proposed Energy Storage Pilot projects are identified as: (1) Horoscope, (2) Mercury 1, and (3) Mercury 2. (*See also*, Ex. SCE-18, Vo. 11, Appendix B, Table 1, p. B-1).

[512] Ex. ORA-09, p. 127:6-8.

[513] D.13-11-025, Finding of Fact 19, p. 113.

[514] D.13-11-025, p. 34.

[515] Ex. ORA-09-WP (Witness Myers), p. 65 (emphasis added).

[516] *See*, D.05-07-039, p. 4; in R.04-04-026. ["Turn-key" is a proposal wherein the developer sells the project to the utility for a pre-determined price at the time the project enters commercial operation.]

Thus, contrary to SCE's claims, the Commission's EPIC rules do not preclude the purchasing of commercially available products for the purposes of executing Commission-authorized EPIC projects. D.12-05-037 explicitly includes the testing and deployment of new strategies within the EPIC Program. To test and execute new applications and strategies, D.13-11-025 explicitly authorized EPIC projects that require the procurement of commercially available battery energy storage systems.

- **SCE's Distributed Energy Storage Integration (DESI) Demonstration Projects**

In Rebuttal, SCE says its expansion of its Distributed Energy Storage Integration (DESI) is a pilot and not a demonstration project.[517] However, SCE's arguments are contradicted by public statements SCE has made that explicitly identify DESI as a demonstration project.[518]

First, documents provided to ORA in discovery[519] show that, in September 2015, SCE's Vice President of Energy Procurement and Management, Colin Cushnie (Mr. Cushnie), attended and presented at the Independent Energy Producers Association's (IEP) 2015 Annual Conference. Mr. Cushnie gave a presentation titled "Distribution Energy Resources: Going Small" wherein Mr. Cushnie identified DESI 1, DESI 2, and DOS as SCE's 2015-2016 demonstration projects.[520]

In response to ORA discovery, SCE attempted to disavow Mr. Cushnie's public statements, claiming instead that DESI 1 and 2, and DOS are pilots. In part, SCE states, "Mr. Cushnie is an executive and does not directly work on the EPIC Program. As such, Mr. Cushnie was not aware of the nuances of the terminology . . . while the slide may have erroneously used the term 'demonstration projects,' SCE's DOS is a pilot project."[521] SCE's attempt to repudiate its own presentation should be given no credence. SCE's response to ORA discovery is also incorrect because SCE's DOS is an EPIC project and therefore, it must be a demonstration

[517] Ex. SCE-18, Vol. 11, pp. 15:27 to 16:11.

[518] Ex. SCE-02, Vol. 11, p. 37:11-12. [The proposed Energy Storage Pilot is an expansion of DESI. SCE states "SCE will expand [DESI] from the initial three pilots previously approved to an additional ten pilots."]

[519] Ex. ORA-102, pp. 11-12.

[520] Ex. ORA-102, pp. 11-12.

[521] Ex. ORA-102, p. 17.

project because "SCE is only permitted to fund EPIC projects in the area of technology demonstration and deployments."[522]

Second, in its 2016 Smart Grid Deployment Plan (SGDP) Annual Report,[523] SCE informed the Commission and stakeholders that it renamed its EPIC DOS project as DESI 3. SCE's 2016 SGDP Annual Report states "[t]he DESI 3 (formerly known as DOS) includes two 500kW, 500kWh battery systems that will support IGP."[524] In response to discovery, SCE confirmed that "DOS stands for SCE's Distributed Optimized Storage project."[525] As stated above, SCE confirmed that "DOS is an EPIC-funded project"[526] and that "SCE is only permitted to fund EPIC projects in the area of technology demonstration and deployments [TD&D]."[527] Thus, "DESI 3 (formerly known as DOS)" must be a demonstration project.

And finally, as recently as the beginning of 2017, SCE's public website provided a "Battery Storage Fact Sheet" where SCE again identifies DESI 1 as a SCE demonstration project.[528]

- **SCE's Unnecessarily Duplicative Energy Storage Pilot**

SCE states that its Energy Storage Pilot is not unnecessarily duplicative of other efforts and that "direct comparisons are difficult as purely equivalent projects do not exist."[529] SCE is wrong.

The Commission has initiated multiple proceedings and authorized the utilities to execute numerous projects to test optimal strategies to deploy energy storage systems in order to advance the State's energy policies. These proceedings include, but are not limited to: (1) Integrated Distribution Energy Resources (IDER), (2) Distribution Resources Plan (DRP); and (3) EPIC Program. SCE does not provide evidence to show that the Energy Storage Pilot will provide

[522] Ex. ORA-102, pp. 4-6.

[523] Ex. ORA-102, p. 1.

[524] Ex. ORA-102, p. 9.

[525] Ex. ORA-102, pp. 1-5.

[526] Ex. ORA-102, pp. 1-5.

[527] Ex. ORA-102, pp. 20-21.

[528] Ex. ORA-102, pp. 20-21.

[529] Ex. SCE-18, Vol. 11, p. 20:19.

benefits and lessons learned that are incremental to the demonstration projects ratepayers are already funding through these Commission-ordered programs.

For example, SCE states that its Energy Storage Pilot is not duplicative of the IDER Framework and Utility Regulatory Incentive Pilots (IDER pilots). The facts show otherwise.

D.16-12-036, the IDER Pilots decision, orders the utilities to select up to four IDER pilots and makes clear that a key objective of the IDER pilots "is to defer or avoid a previously planned distribution project through the procurement of distributed energy resources."[530] SCE says that its Energy Storage Pilot also proposes to test distribution deferral or avoidance.[531] SCE does not provide evidence to show that its Energy Storage Pilot projects do not duplicate the distribution deferral objectives identified for the IDER pilots; rather, SCE only states that the Commission ordered the IDER pilots three months after SCE submitted its 2018 GRC testimony.[532]

This argument has no impact on whether SCE's Energy Storage Pilot duplicates the IDER pilots. Nor does the statutory prohibition against duplication provide for a special temporal exception. In fact, Public Utilities Code section 740.1(d) explicitly states that projects should not unnecessarily duplicate efforts "current, previously, or *imminently* undertaken."[533] The date the Commission ordered for the IDER pilots did not preclude SCE from providing a detailed comparison between the IDER pilots and Energy Storage Pilot to show no duplication exists. SCE did not do so.

SCE's Energy Storage Pilot also duplicates three DRP Demonstration (Demo) projects the Commission ordered the utilities to execute. SCE claims the Energy Storage Pilot does not duplicate the DRP but rather that SCE will "leverage" DESI 2 and 3 for DRP Demo D. Notwithstanding DESI 2 and 3 (discussed in more detail below), SCE's 2018 GRC request is to *expand* DESI from three projects to an additional ten projects.[534] It is these ten additional projects that unnecessarily duplicate the DRP Demo projects. Further, SCE ignores that the

[530] D.16-12-036, FOF 105, p. 73.

[531] Ex. SCE-02, Vol. 11, p. 39:10-22.

[532] Ex. SCE-18, Vol. 11, p. 21:24-25.

[533] Public Utilities Code section 740.1 (emphasis added).

[534] Ex. SCE-02, Vol. 11, p. 37:11-12. ["SCE will expand the pilot program from the initial three pilots previously approved to an additional ten pilots."]

Commission ordered the utilities to execute, not just DRP Demo D, but also DRP Demos C and E. SCE does not refute the fact that its Energy Storage Pilot duplicates these two other DRP Demos as well.

In D.17-02-007, the DRP Demonstration Project decision, the Commission approved SCE's proposals for its DRP Demo C. SCE DRP Demo C is a distribution deferral project. SCE said it identified Demo C's location because "additional load expected from [a] new development and [a] growing region is anticipated to drive the need for traditional distribution system upgrades to address circuit capacity and *duct bank heating issues*."[535] As stated above, SCE's Energy Storage Pilot also proposes to test distribution deferral or avoidance.[536] In fact, SCE states that its Energy Storage Pilot will also assess whether it is able to defer the installation of a new duct bank structure.[537] Specifically, "[SCE] will pilot using energy storage to solve a forecast distribution need triggered by a planning criteria violation of a duct bank temperature limit. The energy storage project could potentially *defer the installation of a new duct bank structure*."[538]

In D.17-02-007, the Commission also approved SCE's Demo D, which tests the ability to manage a grid with a high penetration of DERs.[539] SCE's Energy Storage Pilot also proposes to enable greater DER penetration levels.[540] SCE states it "will pilot energy storage systems to integrate renewable energy and will target areas with existing high penetration of DERs. As the penetration of DERs (such as residential PV arrays) increases on the distribution grid, system upgrades will be required to mitigate the following potential impacts: (1) circuit overload; (2) voltage fluctuation; (3) reverse power flow; (4) system protection and (5) system reconfiguration."[541] In fact, the Commission identified the same potential impacts as critical to

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[535] D.17-02-007, p. 6 [emphasis added], *citing* SCE June 17, 2016 Comments, pp. 3-4.

[536] Ex. ORA-09-WP (Witness Myers), p. 97, citing Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, Attachment, Guidance for Section 769 – Distribution Resource Planning, at p. 7; in R.14-08-013.

[537] Ex. SCE-02, Vol. 11, p. 39:10-22.

[538] Ex. SCE-02, Vol. 11, p. 39:12-15 [emphasis added; cites omitted].

[539] Ex. SCE-02, Vol. 11, p. 39:14-15. *See also*, D.17-02-007 6, *citing* SCE June 17, 2016 Comments, pp. 3-4; in R.14-08-013.

[540] Ex. SCE-02, Vol. 11, p. 40:11-24. *See also,* Ex. SCE-18, Vol. 11, Appendix B, Table 1, p. B-1.

[541] Ex. SCE-02, Vol. 11, pp. 39:24 to 40:2.

the evaluation of DRP Demo D and requires the utilities to collect data specific to these impacts to assess Demo D's performance. [542]

In D.17-06-012, the Revised Track 2 Demonstration Projects decision, the Commission approved SCE's DRP Demo E, which is a microgrid project.[543] SCE's Energy Storage Pilot proposes to support microgrids; however, SCE provides no further information to specify the microgrids it claims it may support. Nor is there evidence to conclude that the Energy Storage Pilot will contribute to SCE's DRP Demo E, or any microgrid for that matter.[544] SCE has also not shown that the Energy Storage Pilot projects are under the $888,000 cost cap[545] established for SCE's DRP Demo E.[546]

Lastly, SCE does not refute ORA's testimony that its Energy Storage Pilot duplicates PG&E's EPIC Project 1.02.[547] PG&E's EPIC Project 1.02 is a utility-owned, 500kW/4 hour lithium-ion battery energy storage system. PG&E purchased this battery energy storage system to test "the ability of a utility operated energy storage asset to address capacity overloads on the distribution system and improve reliability."[548] Equivalent to the PG&E EPIC Project 1.02, SCE states that its Energy Storage Pilot proposes to test "whether energy storage can solve a forecast distribution need triggered by a violation of a planned loading limit."[549]

Public Utilities Code section 740.1 states that utility research and development (R&D) and technology demonstration and deployment (TD&D) "[p]rojects should not unnecessarily

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[542] D.17-02-007, Appendix B [Metrics for Demonstration Projects, C, D, and E], pp. 1-3.

[543] D.17-06-012, OP 3, p. 14; in R.14-08-013.

[544] The only other microgrid the Commission recently authorized SCE to develop, implement and operate is located at the United States' Army National Training Center in Fort Irwin, California (Ft. Irwin Microgrid). However, the Commission stated that the costs for the installation, operation, and maintenance of the Ft. Irwin Microgrid area the responsibility of the Department of Defense and will not be passed on to SCE's customers. Resolution E-4840 ordered the "cost of building and operating the Fort Irwin microgrid project will be borne by the Department of Defense and not passed on to Southern California Edison's other customers." [Resolution E-4840, Order 4, p. 10]

[545] D.17-06-012, p. 11.

[546] SCE claims that two of its Energy Storage Pilots projects may support microgrid projects. [Ex. SCE-18, Vol. 11, Appendix B, Table 1, p. B-1]. However, the budgets for those projects are approximately $5 million each. Specifically, Gemini 3 is $5,214,000 and Apollo is $4,968,000. [Ex. SCE-02, Vol. 11WP, p. 115.]

[547] Ex. ORA-09-WP (Witness Myers), pp. 72-73.

[548] Ex. ORA-09-WP (Witness Myers), p. 73.

[549] Ex. SCE-02, Vol. 11, p. 39:16-17

duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations." The Commission has required the utilities to affirmatively show that their R&D and TD&D requests do not duplicate other efforts.[550] D.12-05-037 states that "funding should not be used to support activities or efforts that are duplicative of efforts that are being undertaken elsewhere or that are more expensive than necessary to achieve the goals."[551] SCE fails to satisfy its burden to make an affirmative showing that its Energy Storage Pilot does not duplicate other activities.

- **SCE's DESI Pilot Expansion Proposal Is Counter to EPIC Cost Caps**

SCE states that "the battery energy storage system [it] will use for [EPIC] DOS will be purchased as part of the Commission-approved DESI pilots."[552] SCE also states "DESI 2 will be used for battery energy storage system in SCE's [EPIC] Integrated Grid Project (DRP Demonstration D.)"[553] By requesting components in the GRC, SCE is piecemealing its EPIC projects in a way that effectively circumvents the cost cap the Legislature and the Commission imposed on the EPIC Program.

Public Resources Code section 25711.7 sets forth a statutory cap on the EPIC Program's budget.[554] This restricts the Commission from increasing the EPIC Program's budget beyond the

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[550] *See*, D.12-12-031, *Authorizing 21st Century Energy Systems* (CES-21), COL 9, p. 91; in A.11-07-08. ["The requirements adopted for the CES-21 program that limit research to four productive areas, require a business case for each project, require a demonstration that the research is not duplicative, and require an annual advice letter filing ensure that all projects funded by the CES-21 program are consistent with the research guidelines set forth in § 740.1."] *See also*, D.12-05-014, *Denying Investment in Silicon Valley Technology Corporation* (SVTC), COL 1, p. 12; in A.10-11-002. ["Investment of ratepayer funds in SVTC is not authorized by Pub. Util. Code §§ 740 and 740.1."]

[551] D.12-05-037, p. 14.

[552] SCE-18, Vol. 11, pp. 12:26 to 13:2 [cite omitted].

[553] SCE-18, Vol. 11, p. 14:19-20. Note: SCE's DRP Demo D is utilizing SCE's EPIC IGP. The project title changes depend on whether the project is discussed in the context of the EPIC Program or the DRP proceeding. [*See*, D.17-02-007, p. 13]

[554] Public Resources Code Section 25711.7(a). ["The Public Utilities Commission shall not require the collection of funds pursuant to its Decision 12-05-037 (May 24, 2012), Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020, as corrected by Decision 12-07-001 (July 3, 2012), Order Correcting Error, and as modified by Decision 13-04-030 (April 18, 2013), Order Modifying Decision (D.) 12-05-037, and Denying Rehearing of Decision, as Modified, in an annual amount greater than the amount specified in those decisions."]

amount authorized in D.12-05-037.[555] In turn, it restricts the utilities from obtaining ratepayer funding for projects beyond the utilities' authorized budget caps. The Commission approves the utilities' EPIC budgets and proposals after determining: (1) "the funding levels for each approved category, program area, project, and initiative are just and reasonable,"[556] and (2) "[b]ecause the Investment Plans . . . are reasonable the approved expenditures of EPIC funds are just and reasonable."[557]

SCE's plan to fund the required battery energy storage system components of its EPIC DOS and IGP projects through the GRC defeats the intent of the cost cap because it masks the true costs of the EPIC projects. For example, SCE states that, as of February 2017, it has only spent $81,861 on its EPIC DOS.[558] The DOS project's cost appears *de minimis* because it does not include the $5,269,000 needed to fund the battery energy storage system.[559] With the battery energy storage system, DOS's budget is $5,350,861.[560] To put it into perspective, DOS, without the battery energy storage system, represents 0.2% of SCE's 2012-2014 EPIC budget, but the project is not functional.[561] When including the required battery energy storage system to make DOS functional, its portion of the SCE's 2012-2014 EPIC budget substantially increases to approximately 16%.[562]

Similarly, SCE is not capturing the true cost of its EPIC IGP. SCE states that, as of February 2017, it spent $14,862,412 on its IGP (Phase 1).[563] However, this does not include the

[555] The Commission authorized an EPIC budget amount of $162.0 million annually beginning January 1, 2013 and continuing through December 31, 2020; the collections are adjusted on January 1, 2015 and January 1, 2018 commensurate with the average change in the Consumer Price Index [D.12-05-037, OP 7, p. 101]. The Commission allocated 20 percent of the total EPIC Program budget to the utilities of which SCE was authorized 41.1 percent of the utilities' allocated funds. [D.12-05-037, OP 5 & 7, pp. 100-101.]

[556] D.13-11-025, COL 9, p. 117.

[557] D.13-11-025, COL 10, p. 117.

[558] Ex ORA-09-WP (Witness Myers), p. 66.

[559] Ex SCE-02, Vol. 11WP, pp. 115. According to Ex. ORA-102, p. 9, DESI 3 is the battery energy storage system used for DOS.

[560] The total DOS budget with energy storage is $81,861 + 5,269,000 = $5,350,861. SCE's 2012-2014 EPIC budget is approximately $33.3 million for TD&D. [D.13-11-025, p. 16.]

[561] $81,861/33.3 M = .0024.

[562] $5,350,861/33.3M = 0.16

[563] Ex. ORA-09-WP (Witness Myers), p. 63.

$5,054,000 SCE requests for DESI 2.[564] Including DESI 2, the actual cost of SCE's EPIC IGP (Phase 1) is $19,916,412.[565]

Excluding the battery energy storage systems costs from SCE's EPIC projects has a significant impact on SCE's EPIC budget. Of the $33.3 million SCE is allocated for its 2012-2014 EPIC budget,[566] SCE states it spent $14,944.273[567] on DOS and IGP (or 44.8% of the budget).[568] However, when factoring in the battery energy storage systems costs, SCE would have spent $25,267,273[569] on DOS and IGP (or 75.84% of the budget).[570] As a result, SCE would only have approximately $8,032,727[571] available to expend on the more than fourteen other EPIC projects it is reportedly executing as part of its 2012-2014 triennial investment plan portfolio.[572] This is a stark departure from the $18,355,727 SCE reports it has without accounting for the battery energy storage systems.[573]

SCE's plan is antithetical to the statutory budget cap imposed on the EPIC Program. It is also contrary to the Commission adopted EPIC budgets. SCE should not be allowed to circumvent its obligation to stay within its allocated EPIC budget by disassembling projects into components and then requesting their funding outside of EPIC. Doing so renders the governing statute and the Commission's orders purposeless. The Commission should deny SCE's request to evade the statutory and Commission imposed budget cap for EPIC Program.

- **Leveraging DESI to Execute EPIC Projects**

SCE claims that it is leveraging DESI 2 and 3 to avoid additional costs.[574] This claim misrepresents the procedural history of the EPIC Program and DESI.

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[564] Ex SCE-02, Vol. 11, WP, pp. 115

[565] Total IGP budget with energy storage is $5,054,000 + $14,862,412 = $19,916,412.

[566] D.13-11-025, p. 16.

[567] $14,862,412 + $81,861 = $14,944,273.

[568] $14,944,273 / 33,300,000 = .44872.

[569] $5,350,861 + $19,916,412 = $25,267,273.

[570] $25,267,273 / 33,300,000 = .7587.

[571] $33,300,000 - $25,267,273 = $8,032,727.

[572] Ex. ORA-09-WP (Witness Roberts), p. 576.

[573] $33,300,000 - $14,944,273 = $18,355,727.

[574] Ex. SCE-18, Vol. 11, p. 21:19-28.

SCE requested the EPIC DOS and IGP (DRP Demo D) projects a year prior to SCE's request for DESI.[575] The Commission authorized SCE to execute DOS and IGP two years before it authorized DESI.[576]

SCE's claim that it decided to "leverage" DESI 2 and 3 is implausible since neither was available at the time SCE requested the DOS and IGP projects; nor was either available when DOS and IGP were approved. At the time SCE requested its EPIC-funded DOS and IGP projects, these were nonexistent assets. SCE's leveraging claim should be rejected.

By seeking ratepayer funding in this GRC for battery storage systems, SCE is not avoiding the cost to procure battery energy storage systems. Instead, DESI 2 and 3 represent additional costs to ratepayers because they should be funded through the EPIC Program.

- **Utility Demonstration Projects Include Used and Useful Assets**

SCE incorrectly claims that the proposed Energy Storage Pilot projects are not demonstration projects because they "will be 'used and useful' through their service lives."[577] This is contrary to the Commission's decision in the Energy Storage Program that states EPIC-funded energy storage projects are eligible to count towards the utilities' energy storage procurement targets and consequently are used and useful assets.

D.13-10-040, the Energy Storage Program decision, set forth the Commission's energy storage policies.[578] In that decision, the Commission found that "[i]t is reasonable to include any PIER- [Public Interest Energy Research] or EPIC-funded projects toward the procurement targets under certain conditions."[579] Consequently, the utilities asked the Commission to permit them to count multiple demonstration projects towards their energy storage procurement targets.

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[575] SCE requested DOS and IGP on November 1, 2012 when it filed A.12-11-004, SCE's 2012-2014 EPIC Triennial Investment Plan. SCE requested its DESI on November 12, 2013 when it filed A.13-11-003, SCE's 2015 GRC.

[576] The Commission authorized DOS and IGP when it approved D.13-11-025 on November 14, 2013. The Commission authorized DESI when it approved D.15-11-021 on November 5, 2015.

[577] Ex. SCE-18, Vol. 11, p. 11:18-20.

[578] D.13-10-040, Table 1, p. 14; in R.10-12-007.

[579] D.13-10-040, Conclusion of Law 10, p. 74. [The conditions referenced include: (1) The project demonstrates its ability to meet one or more of following purposes: grid optimization, integration of renewable energy, or reduction of greenhouse gas emissions; (2) The project is under contract or was installed after January 1, 2010, and (3) The project is operations by no later than the end of 2024. (*See*, D.13-10-040, p. 32.)]

For example, PG&E identified its PIER-funded Vaca-Dixon and Yerba Buena energy storage projects. San Diego Gas & Electric Company identified its PIER-funded Borrego Springs Microgrid Demonstration Project's energy storage systems. And SCE identified its Irvine Smart Grid Demonstration Project's energy storage systems and its Vehicle-to-Grid Los Angeles Air Force Base (V2G-LA AFB) demonstration project.[580]

The Commission granted the utilities' request to count these demonstration projects towards their energy storage procurement targets.[581] Thereafter, the Commission granted PG&E's request to count its EPIC Project 1.02[582] towards its energy storage procurement target.[583]

In D.13-10-040 the Commission clearly determined energy storage systems purchased for the execution of EPIC projects (and other demonstration projects) to be used and useful assets. This is because statute[584] and the Commission's energy storage policies dictate that energy storage procured to meet the Energy Storage Program's procurement targets should serve regulatory functions and satisfy specific use-cases, such as grid optimization, integration of renewable energy, and/or the reduction of greenhouse emissions, which necessarily makes them used and useful assets.[585]

- **Competitive Solicitations for Energy Storage Systems**

Not only are utility-proposed demonstration projects subject to strict standards of review, so are utility requests for utility-owned energy storage systems. As detailed below, utility-owned

[580] Resolution E-4595 (Effective July 11, 2013). ["As a part of this effort, DoD is implementing multi-phase V2G demonstration pilots at six DoD facilities across the United States with an overall goal of evaluating the impact of V2G in making PEVs a cost-effective alternative to conventional internal combustion engines vehicles." (*Id*, p. 3). And, "The V2G Pilot will demonstrate how the battery storage of two fleets of plug-in electrical light duty vehicles may provide energy and ancillary services to the CAISO markets." (*Id*., p. 14)]

[581] D.14-10-045, Attachment A, pp. 1-2; in A.14-02-006 et al.

[582] D.16-09-007, pp. 7-8, fn. 5, *citing* PGE-1 [PG&E 2016 Energy Storage Procurement Prepared Testimony (served March 1, 2016); in A.16-03-001] at 2-1 to 2-6.

[583] D.16-09-007, Conclusion of Law 5, p. 23; in A.16-03-001 et al.

[584] Public Utilities Code section 2835(a)(3). [An "energy storage system" shall be cost-effective and either reduce emissions of greenhouse gases, reduce demand for peak electrical generation, defer or substitute for an investment in generation, transmission, or distribution assets, or improve the reliable operation of the electrical transmission or distribution.].

[585] D.13-10-040, Table 1, p. 14.

energy storage systems "shall be subject to the same evaluation criteria and must meet the same requirements as third-party storage systems."[586] The utility also bears the burden to affirmatively show that a utility-owned energy storage system requested outside of a competitive solicitation is due to "truly extraordinary circumstances"[587] and that holding a competitive solicitation for energy storage systems is infeasible.[588] Moreover, statute dictates that SCE show that it procured cost-effective energy storage.[589] SCE fails to demonstrate that it satisfied the standards of review required for utility-owned energy storage requests.

According to D.13-10-040, "… when proposing a utility-owned project 'the IOU must make a showing that holding a competitive RFO is infeasible. These circumstances may include market power mitigation, reliability, preferred resources, and expansion of existing facilities."[590] The burden to show that it is infeasible to hold a competitive solicitation for utility-owned energy storage is derived from the Commission's policy on Utility-Owned Generation set forth in D.07-12-052, the Decision Adopting the Utilities' 2006 Long-Term Procurement Plans (LTPP). There, the Commission stated "[w]e firmly believe that all long-term procurement should occur via competitive procurements, except in truly extraordinary circumstances."[591] The Commission specified, in detail, the following constitutes truly extraordinary circumstances:

- Market Power Mitigation – the IOU must make a strong showing that as a result of some attribute of the desired resource, a private owner would have the ability to exert significant influence over the price of its development or of the price an quantity of its output (energy, capacity, or ancillary services);

- Preferred Resources – while we continue to rely on markets to deliver efficiently priced products for ratepayers, we see no reason to limit our options and intend to continue to deploy all resources available to use, including utility development and ownership, to meet California's vital environmental policy objectives;

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[586] D.13-10-040, p. 52, *citing* D.12-08-016, *Decision Adopting Proposed Framework for Analyzing Energy Storage Needs*, Appendix A; in R.10-12-007.

[587] D.07-12-052, *Opinion Adopting [PG&E, SCE and SDG&E's] Long-Term Procurement Plans*, p.209; in R.06-02-013.

[588] D.13-10-040, p. 52.

[589] Public Utilities Code section 2836.6.

[590] Ex. SCE-18, Vol. 11, p. 19:18-20.

[591] D.07-12-052, pp. 212-213.

- Expansion of Existing Facilities – we can envision certain unique circumstances in which ratepayers would benefits from development on or expansion of an existing IOU asset that would not lend itself to the PPA project structure, but the IOU would need to make a strong showing that such development were clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership;

- Unique Opportunity – an attractive priced resource resulting from a settlement or bankruptcy proceeding (we anticipate that these opportunities will diminish over time); and

- Reliability – resources needed to meet specific, unique reliability issues (particularly under circumstances in which it becomes evident that reliability may be compromised if new resources are not developed, and the only means of developing new resources in sufficient time is via UOG.[592]

No where in its GRC testimony does SCE explain how its Energy Storage Pilot falls within these defined extraordinary circumstances. The only explanation SCE proffers is "RFOs require a high level of specificity regarding how a resource must be operated under any and all conditions through its intended service life. As a result, resources brought on line through an RFO are inherently inflexible."[593] SCE's explanation, however, is not within the specific categories that warrant relief from the competitive solicitation requirement. It is also inconsistent with the numerous forums wherein SCE procured, or is requesting authorization to procure, energy storage resources.

For example, in its workpapers, SCE requests approval to execute its Distribution Deferral Project Pilot (Deferral Pilot).[594] The "objective of the Distribution Project Deferral Pilot is to demonstrate, initially, on a small scale, that DER can effectively replace/defer traditional distribution upgrade projects without a loss of system reliability."[595] It further states the "purpose of the [Deferral] pilot is to analyze these possible deferral opportunities across a range of characteristics including climate zone, customer and geographic diversity, and DER

[592] D.07-12-052, pp. 211-212.

[593] Ex. SCE-18, Vol. 11, p. 19:21-23.

[594] Ex. SCE-2, Vol. 3-WP, Book C.

[595] Ex. SCE-02, Vol. 3-WP, Book C, p. 10.

performance in concert with grid automation and reinforcement."[596] SCE confirms that it intends to solicit energy storage for the Deferral Pilot.[597] Despite sharing distinctively comparable objectives with the Energy Storage Pilot, SCE states that it will conduct a Deferral Pilot RFO. Specifically, "The basic design of the RFO would be as follows:

- Determine attributes of the circuits that the DERs will serve
- Design pro forma contracts for the attributes
- Reach out to potential DER providers
- Establish schedule for the RFO
- Receive initial offers
- Establish short list of DER providers
- Negotiate specific terms with DER providers
- Seek CPUC approval for the contracts
- Execute contracts
- Deploy DER resources"[598]

Another example is the competitive solicitation process adopted for the DRP Demo projects. D.17-02-007 established an approval process for the utilities to procure new DER to execute DRP Demo projects. According to that decision, the utilities must adhere to 10 solicitation principles, including "Principle 2: Framework utilizes a competitive process with broad markets."[599]

In fact, SCE participated in developing the DRP RFO process, recommending that "[f]or approval of contracts for third-party DER resources, SCE would conduct an RFO and submit a Tier 3 Advice Letter seeking approval for each contract."[600] The Commission adopted this

[596] Ex. SCE-02, Vol. 3-WP- Book C, p. 11. SCE offers the same justification for its Energy Storage Pilot stating "The need for all relevant applications does not exist on one circuit, much less two or three circuits . . . Climate and load conditions introduce additional variability that SCE, and the industry, must better understand." [Ex. SCE-18, Vol. 11, p. 17:9-13].

[597] Ex. SCE-02, Vol. 3-WP, Book C, p. 11, fn. 3.

[598] Ex. SCE-02, Vol. 3-WP, Book C, p. 17.

[599] D.17-02-007, p. 25.

[600] D.17-02-007, p. 29.

recommendation.[601] Furthermore, the Commission imposed a burden on the utilities to "provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives, and should also explain how the DER portfolio was chosen."[602]

In addition, the Commission requires the utilities to conduct competitive solicitations for their IDER pilots[603] and also requires the utilities to conduct biennial competitive solicitations to procure energy storage to meet their mandated targets as part of the Energy Storage Program.[604] SCE conducted a competitive solicitation for its 2013 Local Capacity Requirement (LCR) RFO[605] and "…procured over five times the minimum Energy Storage required in D.13-02-015 [Track I] and D.14-03-004 [Track IV] and a total of 236.64 MW of Energy Storage-based resources."[606]

SCE provides no evidence to substantiate its claim that holding a competitive solicitation for its Energy Storage Pilot is infeasible. As detailed above, competitive solicitations are required in multiple programs and proceedings that focus on objectives for which the purported objectives of the Energy Storage Pilot mirror.

- **Standalone Applications**

In its testimony, ORA noted that the Commission clearly directed SCE to file standalone applications in cases where unforeseen opportunities emerge outside of the EPIC program.[607] Specifically, in D.12-05-037, the Commission stated that it "will not go so far as to prohibit any separate [T]D&D application by [the IOUs], since it is impossible to completely anticipate future opportunities."[608] However, the Commission provided guidance for when the IOUs may use the application process for TD&D proposals and the criteria they must meet. The Commission stated:

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[601] D.17-02-007, OP 26, p. 40.

[602] D.17-02-007, p. 28.

[603] D.16-12-032, OP 4, pp. 78-79.

[604] D.13-10-040, COL 32, & 33, p. 75.

[605] D.15-11-041, p. 11-12.

[606] D.15-11-041, COL 17, p. 35.

[607] Ex. ORA-09, pp. 128:9 to 129:6.

[608] D.12-05-037, p. 29.

> [If the IOUs] propose other such expenditures outside of the EPIC investment plans, [the IOUs] will face a burden to explain why such expenditures could not have been considered within the EPIC program. Any such requests should explain how they meet objectives and metrics of the EPIC program.[609]

Thus, the Commission established a pathway outside of the EPIC program for SCE to seek review and disposition of the Energy Storage Pilot – presupposing SCE demonstrated the request required immediate consideration and adhered to EPIC's objectives and metrics.[610] SCE does not refute ORA's position on this matter. Absent irrefutable evidence, the Commission should find that, pursuant to D.12-05-037, SCE is required to file its Energy Storage Pilot through a standalone application if it intends to request approval of these energy storage demonstrations outside of the EPIC program. There, it will receive the proper and thorough vetting it requires.[611]

As ORA pointed out in its testimony, SCE failed to comply with the Commission's order to inform EPIC stakeholders of outside TD&D requests. To ORA's knowledge, SCE provided no official notification in any EPIC proceeding when or after SCE filed its 2015 GRC. It should also be noted that SCE did not notify the service list of A.14-04-034 (the most recent EPIC proceeding) of its Energy Storage Pilot. SCE's failure to comply with Commission orders in its 2015 GRC should not support SCE's request to violate the Commission's orders again here.[612]

SCE does not refute ORA's position on this matter, and ORA recommends the Commission find that SCE violated the Commission's order in D.12-05-037 by failing to notify the EPIC proceeding service list that it requested its DESI Pilot in its 2015 GRC, and the Energy Storage Pilot in its 2018 GRC.

4.11.2 Advanced Technology Laboratories

SCE has Advanced Technology Laboratories at three locations: the Fenwick Laboratories in Westminster, CA; Pomona Laboratory in Pomona, CA, and the Equipment

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[609] D.12-05-037, OP 17, p. 106.

[610] D.12-05-037, Conclusion of Law (COL) 15, p. 96. The Commission further clarified that the utilities "will face a burden to show why a proposal outside of the EPIC process should be considered immediately and not simply included in the next cycle for EPIC funding consideration by the Commission."

[611] Ex. ORA-9, pp. 129-134.

[612] Ex. ORA-09, p. 135:1-9, *citing* D.12-05-037, Ordering Paragraph 17, p. 106.

Demonstration and Evaluation Facility in Westminster, CA. For Advanced Technology Labs, ORA recommends recovery of 2016 actual expenditures and accepts SCE's forecast for 2017 and 2018. SCE agrees with ORA's recommendations.[613]

4.11.3 Grid Integration Activities

SCE states that its Grid Integration activities "…encompass grid solutions that use technologies we have previously tested, evaluated and piloted, and are now deploying onto the grid."[614] Included in SCE's Grid Integration activities are costs associated with its Distribution Volt VAR Control and Capacitor Automation Program and its Advanced Outage Detection and Analytics Program.

- **Distribution Volt VAR Control and Capacitor Automation Program Capital**

SCE says its Distribution Volt VAR Control (DVVC) Program provides centralized control of field and substation capacitors, to "coordinate and optimize voltage and VARs across all circuits fed by a substation."[615] SCE says this program was authorized in the 2012 GRC, but the program had no recorded expenditures through 2016.[616] SCE indicates that the new DVVC program will replace the existing Capacitor Automation Program, as indicated by the latter being phased out in 2018, the first year the forecast DVVC program expenditures are shown to reach approximately $4.1 million in real dollars.[617]

SCE classifies the DVVC program as a "traditional" program focused on maintaining safety and reliability, rather than a Grid Modernization program focused on enhancing safety and reliability and enabling DER.[618] ORA disagrees. DVVC automates capacitors, transfers data via a field data network, and is controlled by DMS and EMS control software. [619] Each of these are

[613] Ex. SCE-18, Vol. 11, p. 6.

[614] Ex. SCE-2, Vol. 11, p. 1.

[615] Ex. SCE-2, Vol. 11, p. 45.

[616] Ex. SCE-2, Vol. 11, p. 45.

[617] Ex. SCE-2, Vol. 11, p. 45, Figure V-6, and p. 47, Figure V-7.

[618] See Ex. SCE-2, Vol. 3R, Table I-1, p. 19, last row.

[619] Ex. SCE-2, Vol. 11, p. 45.

components of Grid Modernization.[620] In response to discovery, SCE confirmed that components of Volt VAR optimization systems are distribution automation devices.[621]

SCE's testimony fails to mention smart inverters in its discussion of DVVC, which will provide Volt VAR control as part of the approved Phase 1 functions, as discussed above in connection with SCE's Grid Modernization proposals. Even if SCE's system does not rely on smart inverters to perform voltage conservation, it must provide for and function under the presence of smart inverters with autonomous Volt VAR capabilities.

ORA, therefore, recommends 2016 DVVC expenditures at 2016 recorded values, and zero expenditures for 2017 and 2018. These recommendations are consistent with ORA's overall recommendation to use 2016 recorded values, and with ORA's recommendations relating to SCE's Grid Modernization proposals.[622]

The existing Capacitor Automation program could also be characterized as Grid Modernization, but since it is an existing program, ORA recommends this program continue through the rate case period at historical expenditure levels in lieu of the DVVC program. ORA recommends 2016 non-DVVC Capacitor Automation expenditures at 2016 recorded values, expenditures for 2017 at the average of 2014-2016 recorded expenditures, and 2018 expenditures at those forecast for 2017 plus escalation.[623]

- **Advanced Outage Detection and Analytics Program**

SCE says its Advanced Outage Detection and Analytics program aims to enhance the capabilities of SCE's infrastructure "… and utilize the collective data to improve public safety, outage detection, outage notification, response and work practices."[624]

4.11.4 Capital

ORA accepts SCE's justification for this new program, in part because it seeks to leverage the existing AMI system.[625] SCE requests a total of $43.247 million for 2018-2020,

[620] Automating switched capacitors is distribution automation, as are automatic switches. SCE proposes a new FAN to provide communication with an increased number of automated field devices, including capacitors. Finally, SCE is proposing to replace the DMS and EMS systems with a new GMS.

[621] Ex. ORA-9-WP, p. 62, Book 1. *See* SCE response to data request ORA-SCE-029-TCR, Q.2.

[622] Ex. ORA-9, p. 123.

[623] Ex. ORA-9, p. 123. The historic or non-DVVC Capacitor Automation Program is defined by WBS element CET-PD-LG-CV-MTW as shown in Figure V-7 of Ex. SCE-2, Vol. 11, p. 47.

[624] Ex. SCE-18, Vol. 11, p. 27.

but, as shown in SCE's testimony the expenditures are front loaded to 2018.[626] ORA therefore recommends 2018 expenditures equal to the average of SCE's 2018-2020 forecasts, or $14.416 million.[627]

4.12 T&D Safety Training and Environmental Programs

The Transmission & Distribution Safety, Training and Compliance organization is responsible for assessing, designing, developing, implementing, and evaluating technical and safety training programs specifically for SCE's T&D employees to ensure that employees are trained and prepared to perform various system maintenance activities while complying with regulatory requirements and laws.[628]

SCE's recorded adjusted expenses for its Safety, Training, and Environmental Programs decreased by $13.073 million between 2011 and 2015, from $72.177 million in 2011 to $59.104 million in 2015. SCE states it "recorded $59 million, $11 million less than authorized amounts due to lower spending for environmental programs, hazardous waste disposal, and safety and recognition."[629]

SCE forecasts $62.081 million for its Safety, Training and Environmental Programs expenses.[630] SCE developed its forecast by using its 2015 recorded adjusted expenses plus incremental expenses for proposed projects and activities. The corresponding ORA estimate is $59.179 million. ORA's estimate is $2.902 million less than SCE's estimate.[631]

SCE combined the forecast expenses from six FERC sub-accounts to calculate its forecast of $62.081 million for its Safety, Training and Environmental Programs expenses. Of these, ORA disagrees with SCE's forecasts for FERC sub-account 565.281, Corporate Environmental Health and Safety – Transmission, and FERC sub-account 598.250, Hazardous Waste Disposal – Distribution.

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[625] Ex. SCE-2, Vol. 11, p. 50.

[626] Ex. SCE-2, Vol. 11, p. 50.

[627] Ex. ORA-9, p. 123, footnote 416: This adjustment was made to RO Model ID 661-663 by reducing each 2018 forecast by 71.56%, which is $14.416/$20.114.

[628] Ex. SCE-2, Vol. 12, p. 1.

[629] Ex. SCE-2, Vol. 12, p. 3.

[630] Ex. SCE-2, Vol. 12, p. 2.

[631] Ex. ORA-7, p. 35.

- **FERC Sub-Account 565.281**

SCE forecasts $4.608 million for FERC sub-account 565.281 (Labor of $0.356 million and Non-Labor of $4.252 million) for its Environmental Programs - Transmission expenses.[632] SCE's forecast of $4.608 million is an increase of $1.710 million or 59% over 2015 recorded adjusted expenses of $2.898 million. SCE developed its forecast by averaging its forecast expenses for 2018 through 2020 as the basis for its TY 2018 forecast. ORA forecasts $2.898 million using SCE's 2015 recorded adjusted expenses for its estimate. ORA's estimate is $1.710 million less than SCE's forecast.[633]

SCE's forecast includes funding for deferred maintenance projects and programs that were included in its 2015 GRC.[634] SCE had 2016 and 2017 to catch up on its deferred maintenance programs and projects before the TY. Ratepayers should not be paying twice for the same activities that were already funded in SCE's prior rate case. SCE's forecast also includes funding for 3.1 full time positions.[635] SCE requested and was authorized funding in its 2015 GRC that was 607.80% over its 2012 recorded adjusted expenses.[636]

ORA asked SCE to identify the 2015 Environmental Programs and associated costs that SCE forecast and state which ones were deferred or eliminated. According to the response SCE provided, of the 26 projects SCE submitted in its TY 2015 GRC, 15 were deferred, and 5 were eliminated.[637]

SCE's forecast in this GRC includes funding for deferred maintenance projects and programs that were included in its 2015 GRC.[638] SCE had 2016 and 2017 to catch up on its

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[632] Ex. SCE-2, Vol. 12, p. 33. In SCE's 2015 GRC, it recorded its Corporate Environmental Health and Safety – Transmission expenses (called Transmission Environmental Services expenses in 2015 GRC) in Account 566.250. SCE records the expenses for this activity in Account 565.281 in its 2018 GRC.

[633] Ex. ORA-7, p. 38.

[634] Ex. ORA-7, p. 38, footnote 107: ORA-SCE-077-TLG, Q.17-a. In SCE's 2015 GRC, it showed recorded expenses for 2011 and 2012. For SCE's 2018 GRC, it does not show any recorded expenses for 2011 and 2012 for Account 565.281.

[635] Ex. SCE-2, Vol. 12, p. 28.

[636] Ex. ORA-7, p. 38, footnote 109: In SCE's 2015 GRC, it was authorized $5.456 million (ORA-SCE-Verbal-006, Q.1).

[637] Ex. ORA-114; 14 RT 1927-1929, Neal/SCE.

[638] Ex. ORA-7-WP, p. 7-29—7-30 (ORA-SCE-077-TLG, Q.17-a.) In SCE's 2015 GRC, it showed recorded expenses for 2011 and 2012. For SCE's 2018 GRC, it does not show any recorded expenses for 2011 and 2012 for Account 565.281.

deferred maintenance programs and projects before the TY. Ratepayers should not be paying twice for the same activities that were already funded in SCE's prior rate case.

Regarding deferred maintenance the Commission has stated the following:[639]

> For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future. Consequently, we will disallow recovery of the $34.6 million requested for deferred maintenance activities in 1983 and 1984. Our disallowance of this expense for test year ratemaking purposes does not relieve Edison of its responsibility to maintain the operating efficiency of its utility plant in a timely manner. Indeed, we expect Edison to fulfill that responsibility more conscientiously in the future.

Consistent with Commission policy regarding deferred maintenance, SCE's shareholders, and not its ratepayers, should be responsible for additional costs associated with deferred maintenance. The Commission should adopt ORA's TY recommendation of $2.898 million for this sub-account.

- **FERC Sub-Account 598.250**

For FERC sub-account 598.250, Hazardous Waste Disposal – Distribution expenses, SCE forecasts $3.551 million.[640] SCE's forecast is an increase of $1.192 million, or 50.53%, over 2015 recorded adjusted expenses of $2.359 million. SCE used a four year average (2012-2015) as the basis of its TY 2018 forecast. ORA forecasts $2.359 million using SCE's 2015 recorded adjusted expenses. ORA's estimate is $1.192 million less than SCE's forecast.

SCE's request for an increase of 50.53% should be denied. SCE's recorded adjusted expenses have declined each year between 2011 and 2015 from $5.997 million in 2011 to $2.359 million in 2015, which is a total decrease in expenses over this period of $3.638 million.[641] In

[639] *SoCal Edison* (1982) 10 CPUC 2d 155, 186; D.82-12-055, 1982 Cal. PUC LEXIS 1209.

[640] Ex. SCE-2, Vol. 12, p. 37.

[641] Ex. ORA-7-WP, p. 7-33 (ORA-SCE-077-TLG, Q.16-a).

SCE's 2015 GRC, the Commission authorized SCE $5.305 million,[642] which is $2.946 million more than its 2015 recorded adjusted expenses of $2.359 million. SCE had 2016 and 2017 to catch up on deferred projects.

ORA asked SCE to:

> Provide the documentation that identifies the 2015 Hazardous Waste Disposal - Distribution projects and associated cost that SCE completed as forecast and the forecast projects that were deferred or eliminated (SCE's 2015 GRC forecast was $5.120 million for this line item).

SCE's response was:

> SCE's forecast of Hazardous Waste Disposal-Distribution was not based on individual projects, so we cannot identify any projects which were deferred or eliminated. Please refer to Exhibit SCE-03, Volume 9 from A.13-11-003 where these expenses are discussed in SCE's 2015 GRC application. Please also refer to page 181 in D.15-11-021, where the Commission adopted SCE's forecast for these accounts.[643]

SCE's statement above is problematic. On one hand, SCE states it is not able to track and identify projects and related authorized funding from its 2015 GRC. Yet in its 2018 GRC, SCE says it has identified projects and calculated incremental funding for an account that has shown a declining trend in expenses each year between 2011-2015.

SCE says that, although its costs have shown a downward trend from 2011-2015, there has been an increase in the amount of samples done year-over-year. SCE says it has plans for its own in-house lab to begin testing soil samples at the end of 2016.

SCE's historical expenses include costs embedded in rates for activities performed by SCE's its in-house lab for performing soil samples, and incremental funding for on-going activities should not be required.

In examining the relationship between embedded historical costs and forecast expenses for the same or similar activities, the Commission stated the following in its decision in SCE's TY 2009 GRC:

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[642] Ex. ORA-7, p. 41, footnote 117, citing SCE response to ORA-SCE-Verbal-006, Q.1.

[643] Ex. ORA-7-WP, p. 7-33.

> SCE's forecast also includes a $4.812 million (constant 2006$) increase for insulator replacement as part of its Transmission Life Extension Program. SCE claims that the increase represents the cost of materials and the use of contract crews to supplement SCE's crews for insulator and hardware replacements. DRA claims historical expenses have embedded costs for insulator replacements. According to SCE, some of the circuits it will be replacing are over 90 years old and many of the insulators on its system have exceeded their life expectancies. While these types of programs may be a cost-effective way to maintain the integrity of the system and slow the deterioration of capital assets, SCE has not sufficiently addressed the relationship of these programs to costs embedded in historical data. Accordingly, SCE's request for $4.812 million to increase its insulator replacement as part of its Life Extension Program is denied.[644]

Despite SCE's claims of increased activity, SCE's recorded adjusted expenses have demonstrated a continuous decline. SCE has not shown that additional funding over 2015 expense levels is necessary.[645]

4.13 T&D Other Costs, Other Operating Revenues

In its Direct Testimony, SCE forecast $130.943 million for T&D Other Costs saying that it developed its forecast by using its 2015 recorded adjusted expenses and historical averages plus incremental funding for proposed TY activities.[646] The corresponding ORA estimate for SCE's Other Costs is $122.638 million.[647]

This organization is responsible for providing operational support to SCE's T&D organization. Some of its activities include managing projects and programs for Grid Interconnection Contract Development, Reliability Standards and Compliance, Grid Contract Management, Distribution Construction Contract Management and Real Properties groups. This organization also performs activities associated with work order write-offs, claims, line rents, underground locating and other support activities.[648]

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[644] D.09-03-025, p. 72.

[645] Ex. SCE-2, Vol. 12, p. 30.

[646] Ex. SCE-2, Vol. 13, p. 5. SCE's Rebuttal Testimony corrected the 2015 recorded adjusted expenses to $115.136 million. Ex. SCE-18, Vol. 13, p. 2.

[647] Ex. ORA-7, p. 43.

[648] Ex. SCE-2, Vol. 13, p. 1.

SCE combined the forecast expenses from ten FERC sub-accounts to calculate its forecast of $130.943 million for T&D Other Costs. Of those ten sub-accounts, ORA opposes only SCE's TY forecasts for FERC sub-account 560.281, Transmission Work Order Write Offs and Transmission Capital Related Expense, FERC sub-account 594.281, Distribution Capital Related Expense, and FERC sub-account 588.281, Distribution Work Order Write-Offs/ Distribution Line Rents/Underground Locating Service.

- **FERC Sub-Account 560.281**

SCE forecasts $15.041 million for the two line items included in Sub-Account 560.281 (Labor of $2.677 million and Non-Labor of $12.364 million): Transmission Work Order Write-Offs of $2.404 million and Transmission Capital Related Expense of $12.637 million.[649] ORA's forecast is $13.437 million.[650]

The forecast method SCE used to calculate its incremental funding request for the line item Transmission Work Order Write-Off expenses recorded in Account 560.281 is not justified. SCE's recorded adjusted expenses declined by $3.240 million between 2013 and 2015 from by $4.206 million in 2013 to $0.966 million in 2015.[651] SCE's TY forecast for Transmission Work Order Write-Offs does not include any labor proposals for additional staff. SCE's TY estimate, based on a five year average,[652] provides SCE with incremental labor funding over 2015 recorded adjusted expenses of 75.09%. ORA recommends the Commission adopt a test year expense level of $13.437 million for this account.[653]

- **FERC Sub-Account 594.281**

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[649] Ex. SCE-2, Vol. 13, p. 31. SCE's forecast of $2.404 million for Transmission Work Order Write-Offs is based on a five year average. For its forecast of $12.637 million for Transmission Capital Related Expense, SCE developed a five-year (2011-2015) weighted average ratio from capital-related expense and capital expenditures (including pole loading program recorded expenses (Account 571.125) and pole loading program capital expenditures). SCE then calculated the 2018 forecast "by multiplying the capital-related expense ratio by the forecast capital expenditures for each year and normalizing for 2018 Test Year." (Ex. SCE-2, Vol. 13, p. 29).

[650] Ex. ORA-7, p. 50.

[651] SCE's expenses show a downward trend and the last recorded year method is appropriate. In regards to another downward trend in expenses recorded in Account 588.140 SCE states "Our forecast is also consistent with Commission guidelines that state if costs have shown a trend, the last year recorded is an appropriate basis for the forecast" (Ex. SCE-2, Vol. 5, p. 8).

[652] Ex. SCE-2, Vol. 13, p. 16. SCE has not proposed any staffing increases in the TY for Account 560.281 (ORA-SCE-142-TLG, Q.1-d.

[653] Ex. ORA-7, p. 50.

SCE forecasts $40.725 million for Sub-Account 594.281 (Labor of $4.982 million and Non-Labor of $35.742 million) for Distribution Capital Related Expense.[654] ORA forecasts $34.923 million for Account excluding historical and forecast pole loading program expenses and capital expenditures)[655] as a basis for its estimate. ORA also excluded from its TY estimate for Account 594.281 adjustments SCE made to the years 2011-2015 for "Compatible Units",[656] a methodology SCE plans to implement in the future for on-going activities recorded in Account 594.281. ORA's estimate is $5.802 million less than SCE's forecast.[657]

SCE's recorded adjusted expenses recorded in Account 594.281 have been relatively stable between 2014 and 2015. Regarding the relationship between capital-related expense and capital expenditures, SCE states "as capital expenditures increase or decrease, there is a corresponding change to related expense".[658] If SCE's TY capital expenditures forecast is not adopted as proposed, the TY forecast for Accounts 594.281 and 560.281 will need to be adjusted accordingly.

During its review and analysis of the methodology SCE used to calculate its TY forecast for capital-related expense recorded in Accounts 560.281 and 594.281, ORA found that SCE properly excluded forecast Pole Loading Program capital expenditures as discussed in its 2015 GRC for these accounts.[659] However, SCE erroneously used historical (2014-2015) Pole Loading Program recorded expenses (Accounts 571.125 and 593.125) and Pole Loading

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[654] Ex. SCE-2, Vol. 13, p. 38. For its forecast of $40.725 million for Distribution Capital Related Expense, SCE developed a five-year (2011-2015) weighted average ratio from capital-related expense and capital expenditures (including pole loading program recorded expenses (Account 593.125) and pole loading program capital expenditures). SCE then calculated the 2018 forecast "by multiplying the capital-related expense ratio by the forecast capital expenditures for each year and normalizing for 2018 Test Year." (Ex. SCE-2, Vol. 13, p. 29).

655 In ORA's TY estimate of $34.923 million for Account 594.281, it utilized the weighted average ratio of 1.76% (changed from 2.05%) for Distribution Capital Related Expense. This ratio of 1.76% also excludes SCE's historical adjustment to the years 2011-2015 for its proposed future methodology for Compatible Units (ORA-SCE-142-TLG, Q.9-f).

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

[657] Ex. ORA-7, p. 46.

[658] Ex. SCE-2, Vol. 13, p. 27.

[659] D.15-11-021, p. 188.

Program capital expenditures to develop the weighted average ratio SCE then used to calculate TY forecasts for 560.281 and 594.281.[660]

In its decision on SCE's TY 2015 GRC, the Commission stated the following:

> ORA proposes a 5YA of recorded expenses for Account 594.281, but accepts SCE's forecast for Account 560.281. ORA cites its belief in embedded funding and notes that SCE's capital expenditure forecast may not be entirely adopted. SCE discusses certain inconsistencies in ORA's testimony, including that ORA only makes its proposal for the FERC account for which it leads to a reduction. SCE concludes that we should adjust these forecast only based on adjustments to the capital forecast, *excluding pole loading*. We agree with SCE that this forecast should be based on the historical relationship and the adopted capital forecast. Accordingly, we adjust SCE's forecasts for each account by 10% to approximate our reductions to non-pole loading capital expenditures, as shown below (millions of 2012$)…[661]

SCE apparently interprets D.15-11-021 as allowing SCE to combine Pole Loading Program expenses and capital expenditures for purposes of calculating a ratio to make its forecast for Distribution Capital Related Expense. ORA's interpretation is exactly the opposite. Pole Loading Program expenses and capital expenditures should be completely excluded from the TY forecast calculation for Accounts 594.281 and 560.281.

SCE's forecast for Account 594.281 also includes an inappropriate methodology for the line item "Adjustment for Compatible Units." SCE did not incur these expenses in Account 594.281 during the historical years 2011-2015. SCE imputed these expenses.

When ORA asked why SCE included these non-existent expenses in its TY calculation for historical 2011-2015 years, SCE responded that:

> Because SCE uses a historical ratio of capital related expense to capital expenditures, the historical 2011-2015 years needed to be modified to present those costs as if they were incurred using the future methodology. The inclusion of compatible unit costs in 2011-2015 in Table III-18 was done to clearly demonstrate the calculation of the forecast; SCE did not make adjustments to

[660] Ex. SCE-2, Vol. 13, p. 29 and Ex. ORA-7, p. 47, footnote 133 citing to Ex. SCE-2, Vol. 13 workpapers, p. 342.

[661] D.15-11-021, p. 188, emphasis added.

historical recorded costs for the forecast change due to the compatible unit method for recording related expense. [662]

This is a methodology that SCE proposes to implement for future activities recorded to Account 594.281. If SCE implements this methodology in the TY, the costs and related activity performed under that new methodology will be captured and demonstrated in SCE's next GRC. Using a future proposed method is not a valid means of analyzing historical costs. ORA, therefore, removed SCE's Adjustment for Compatible Units from its TY estimate of $34.923 million for Account 594.281. ORA's estimate of $34.923 million is comparable to SCE's 2015 recorded adjusted expenses of $34.607 million and ORA recommends the Commission adopt it.[663]

- **FERC Sub-Account 588.281**

SCE forecasts $18.868 million for Sub-Account 588.281 (Labor of $2.287 million, Non-Labor of $13.692 million, and Other expenses of $2.889 million) for its Distribution Work Order Write-Offs, Distribution Line Rents, and Underground Locating Service expenses.[664] SCE's forecast of $18.868 million is an increase of $5.516 million or 41.31% over 2015 recorded adjusted expenses of $13.352 million. SCE used a five-year average after adjustments to calculate its TY forecast.

ORA forecasts $17.969 million using SCE's 2015 recorded adjusted expenses and SCE's 2018 TY forecasts as a basis for its estimate for SCE's Sub-Account 588.281. ORA's estimate is $0.899 million less than SCE's forecast.[665]

SCE's expenses for the three line items recorded in Sub-Account 588.281 declined by $8.216 million between 2011 and 2015, from $21.568 million in 2011 to $13.352 million in 2015. ORA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its TY estimates for Sub-Account 588.281.

[662] Ex. ORA-7-WP, p. 7-42 – 7-43 (ORA-SCE-142-TLG, Q.9-g.)

[663] Ex. ORA-7, p. 47.

[664] Ex. SCE-2, Vol. 13, p. 37.

[665] Ex. ORA-7, p. 50.

ORA does not oppose SCE's TY forecast for its line items for Distribution Line Rents of $2.889 million and Underground Locating Service of $8.590 million.[666] ORA does, however, object to SCE's line item for Distribution Work Order Write-Offs of $7.389 million.

ORA forecasts $6.490 million for SCE's Distribution Work Order Write-Offs. ORA uses SCE's 2015 recorded adjusted labor expenses and SCE's TY forecast for non-labor expenses as a basis for its estimate. ORA's forecast is $0.899 million less than SCE's TY forecast of $7.389 million.

SCE's recorded adjusted expenses for labor declined each year between 2011 and 2015 from $3.221 million in 2011 to $1.353 million in 2015.[667] SCE's TY forecast for Distribution Work Order Write-Offs does not include any labor proposals for additional staff. SCE's TY estimate, based on a five year average, provides SCE with incremental labor funding of $0.899 million over 2015 recorded adjusted expenses of $1.353 million or an increase of 66.44%. SCE has not justified this.[668]

SCE's labor expenses have declined and it has not provided any support for an increase of 66.44% in the TY for additional positions.[669] ORA recommends the Commission adopt a forecast of $6.490 million for FERC sub-account 588.281.

4.14 T&D Additional Issues

ORA has no additional issues at this time.

5. CUSTOMER SERVICE

5.1 Customer Service- O&M

For SCE's CS expenses for TY 2018, ORA agrees with SCE's following forecasts:

- $5.122 million for FERC Account 901;

[666] SCE's forecast for Underground Locating Service of $8.590 million is comparable to its 2015 recorded adjusted expenses of $8.411 million. The recorded expenses have declined by $2.182 million between 2011 and 2015. SCE's 2015 recorded adjusted expenses of $8.411 million is $2.128 million less than authorized in its 2015 GRC of $10.539 million (ORA-Verbal-006, Q.1).

[667] SCE's labor expenses show a downward trend and the last recorded year method is appropriate. In regards to another downward trend in expenses recorded in Account 588.140 SCE states "Our forecast is also consistent with Commission guidelines that state if costs have shown a trend, the last year recorded is an appropriate basis for the forecast" (Ex. SCE-2, Vol. 5, p. 8).

[668] Ex. ORA-7, p. 53.

[669] Ex. ORA-7, p. 54.

- $10.165 million for FERC Account 902;
- $5.826 million for FERC Account 580;
- $4.875 million for FERC Account 586.100;
- $15.511 million for FERC Account 586.400;
- $6.932 million for FERC Account 587 ORA;
- $2.487 million for FERC Account 907.60;
- $24.442 million for FERC Account 905.900; and
- Uncollectable factor of 0.216% for FERC Account 904 which is the same as SCE's forecast.

ORA, recommends forecasts that are lower than SCE's forecasts for the following accounts:

- $15.792 million for FERC Account 903.200 which is $333,000 or 2 percent less than SCE's forecast;
- $25.190 million for FERC Account 903.500 which is $3.082 million or 10.5 percent less than SCE's forecast;
- $39.489 million for FERC Account 903.800 which is $6.8 million or 15 percent less than SCE's forecast; and
- $18.519 million for FERC Account 908.600 which is $88,000 or <1 percent less than SCE's forecast.[670]

5.1.1 FERC Account 903.500: Revenue Services Organization Billing Services

FERC Account 903.500 captures costs for SCE's Revenue Services Organization (RSO) Billing Group, which manages, maintains, and supports the customer usage and billing processes and program operations.[671]

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 903.500.[672]

[670] Ex. ORA-12, pp. 2-3.

[671] Ex. SCE-03, p. 69.

[672] Ex. ORA-12, p. 14.

FERC Account 903.500
2011-2015 Recorded Expenses
(in Thousands of Dollars ($2015))[673]

FERC Account 903.500	2011	2012	2013	2014	2015
Labor	$24,694	$23,196	$21,680	$20,364	$19,730
Non-Labor	$9,388	$7,699	$7,936	$7,137	$7,230
Other	$221	$656	$235	$259	$460
Total	$34,303	$31,551	$29,851	$27,760	$27,420

The following table presents SCE's and ORA's 2018 forecasts for FERC Account 903.500.:

FERC Account 903.500
2018 Forecasted Expenses
(in Thousands of Dollars ($2015))

FERC Account 903.500	SCE 2018	ORA 2018	Difference SCE>ORA
Labor	$19,732	$17,933	$1900
Non-Labor	$7,810	$6,891	$933
Other	$615	$366	$249
Total	$28,157	$25,190	$3,082

SCE requests $28.157 million, which is an increase of $737,000 or 3% above 2015 recorded expenses for FERC Account 903.500. SCE made an upward net adjustment of $1.886 million in program changes. This figure includes four changes: (1) a downward adjustment of $94,000 in policy adjustments from using a five year average; (2) an upward adjustment of $249,000 for a service guarantee, where SCE argues for ratepayers to fund a "baseline level" of the costs associated with SCE's service guarantee program, rather than shareholders, which is the current policy; (3) an upward adjustment of $568,000 to account for increasing numbers of Net

[673] 2011-2015 data from Ex. SCE-3, p. 76.

Energy Metering (NEM) applications and (4) SCE made an upward adjustment of $1.163 million to account for incremental Community Choice Aggregation (CCA) enrollment processing, that will be offset by the proposed 2018 CCA service fees and Other Operating Revenue.[674]

SCE requests $2.833 million associated with hiring temporary supplemental staff in 2019 for the CS Re-Platform project. This includes $1.9 million to hire 66 full-time employees (FTEs) as SCE labor supplemental staff, as well as $933,000 to hire 42 FTEs as contract services.[675]

Additionally, SCE made a reduction of $423,000 from the expected CS Re-Platform benefits that will be actualized in 2018.[676]

Lastly, SCE made a downward adjustment of $4.178 million in Operational Excellence savings. This includes a reduction of $1.257 million from electronic billing, a reduction of $1.594 million in vendor partnering, and a reduction of $1.328 million in support function.

5.1.1.1 ORA's Recommendation for FERC Account 903.500

ORA recommends $25.19 million for FERC Account 903.500, which is $3.082 million or 11% less than SCE's request. ORA does not oppose the upwards adjustment for NEM application processing and new CCA enrollment, however, but ORA opposes the following requests:

5.1.1.1.1 Service Guarantee Program

ORA objects to SCE's $249,000 request to establish a baseline level of the service guarantee credits to be funded by ratepayers as a normal cost of business. SCE's Service Guarantee Program began in 2004 and includes four separate service guarantee standards: (1) Missed Appointments, (2) Service Restoration (within 24 hours), (3) Planned Outage Notification and (4) Timely and Accurate First Bill. SCE pays a $30 credit to customers for each incident when these standards are not met. Shareholders currently fund these credits.

SCE now requests a baseline level of the service guarantee credits should be funded by ratepayers as a "normal cost of business" and not by SCE's shareholders. Since SCE's Service Guarantee Program began in 2004, SCE has requested a baseline level of service credits be funded by ratepayers in the last three GRC cycles. In the last three GRCs, the Commission has agreed with ORA that shareholders should continue to fund credits to inconvenienced customers

[674] Ex. SCE-03, p. 83.

[675] Ex. SCE-03, p. 84.

[676] Ex. ORA-12, p. 16.

through the service guarantee program.[677] ORA recommends that SCE's Service Guarantee Program funding request of $249,000 be denied and that SCE's shareholders continue to fund any credits to customers when SCE does not meet its customer obligations.[678]

5.1.1.1.2 CS Re-Platform

ORA objects to SCE's request to include the funding of $2.833 million in the test year to hire temporary, supplemental staff for the CS Re-Platform project. ORA recommends denying SCE's $2.833 million request to fund the hiring of additional staff, which will not occur until 2019, and recommends instead that SCE track costs associated with hiring supplemental staff for the CS Re-Platform in a memorandum account. A memorandum account will protect ratepayers from the uncertainty associated with whether SCE will actually require the additional funding for an expense it will not incur until 2019 which is after the 2018 test year and whether it will execute its CS Re-Platform as planned, versus being delayed.[679]

As described in Ex. SCE-04, Vol. 3, SCE plans to implement the Customer Service Re-Platform capitalized software project in 2020. CS Re-Platform costs for RSO include two components: (1) RSO supplemental staff costs and (2) RSO staff augmentation-contractor costs. SCE claims that it needs to hire temporary staff in 2019 to maintain the legacy billing system while SCE's current employees learn/receive training on the new SAP billing platform.[680]

SCE plans to employ the supplemental staff for 19 months. SCE's timeline for the 19 months includes: training on the legacy system from June to July 2019, training on the new SAP based CR&B module from August to December 2019, and support billing processes on the new SAP CR&B system from January to December 2020. See the table below for visualization of SCE's proposed timeline.[681]

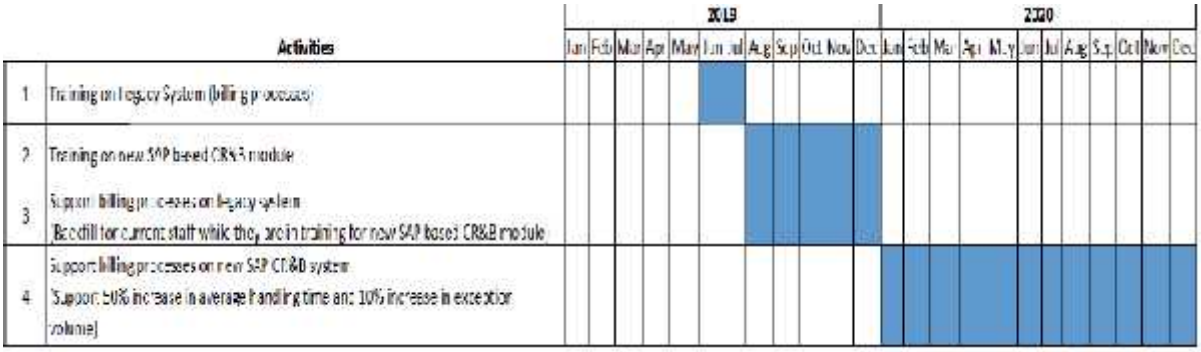
[677] D.06-05-016, p. 122; D.09-03-025, p.108; D.12-11-051, p. 228.

[678] Ex. ORA-12, p. 16.

[679] Ex. ORA-12, p. 17.

[680] Ex. SCE-03, p. 84.

[681] SCE response to data request ORA-SCE-124-CY3, Q.1.b.



It is uncertain whether the proposed hiring, training and employment schedule of the supplemental staff will be completed by SCE's proposed timeline of December 2020. If the CS Re-Platform startup timeline is delayed beyond 2020, then the costs will lie outside of the attrition years in this GRC cycle.

The number of supplemental staff SCE proposes adding is unprecedented and highly uncertain. In this GRC cycle, SCE proposes to adding total of 108 additional FTEs: 66 FTEs as SCE labor and 42 FTEs as contract services for the RSO Billing Services group. Below is a table SCE provided of the RSO Billing Services Group historical staffing levels:[682]

Table I
903.500 Billing Services
FTE and Supplemental - Year End Totals

	2011	2012	2013	2014	2015	2016
EMPLOYEE	363	372	299	255	258	246
SUPPLEMENTAL	14	2	10	24	35	30
Grand Total :	377	374	309	279	293	276

As shown in Table I above, the greatest addition of employees in the past 6 years occurred when SCE added 14 new supplemental staff from 2014 to 2015. Under SCE's proposal, the addition of 108 FTEs as temporary supplemental staff in 2019 would increase the number of supplemental employees by 260% from 2016 levels and increase the number of overall employees by 61% from 2016 levels. This level of hiring—supplemental or otherwise— is unprecedented in the RSO Billing Services group staffing history of the past 6 years.

ORA proposes that the expenses associated with the supplemental staff for the CS Re-Platform be tracked in a memorandum account. SCE can file an advice letter for recovery of

[682] SCE's response to data request ORA-SCE-124-CY3, Q.1.a.

these costs after the completion of the CS Re-Platform project. SCE should be required to show that such costs tracked in the memorandum account were incremental to its authorized expenses.[683]

5.1.2 FERC Account 903.200: Credit and Payment Services

FERC Account 903.200 captures costs for SCE's Credit Group and Payment Services Group. The Credit Group establishes, maintains and enforces credit policies and practices. The Payment Services Group assists customers in making their payments on time by providing numerous payment options such as by mail, in person through an Authorized Payment Agency (APA) or Rural Office, or through one of the electronic payment options.[684]

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 903.200.

FERC Account 903.200
2011-2015 Recorded Expenses
(in Thousands of Dollars ($2015))[685]

FERC Account 903.200	2011	2012	2013	2014	2015
Labor	$18,704	$10,681	$10,541	$9,939	$10,085
Non-Labor	$10,579	$8,214	$7,466	$6,706	$6,263
Total	$29,283	$18,895	$18,007	$16,645	$16,348

The table below presents SCE's and ORA's 2018 forecasts for FERC Account 903.200:

[683] Ex. ORA-12, p. 18.

[684] Ex. SCE-03, p. 87.

[685] 2011-2015 data from Ex. SCE-3, p. 95.

FERC Account 903.200
2018 Forecast Expenses
(in Thousands of Dollars ($2015))

FERC Account 903.200	SCE 2018	ORA 2018	Difference SCE>ORA
Labor	$9,626	$9,393	$233
Non-Labor	$6,499	$6,399	$100
Total	$16,125	$15,792	$333

SCE requests $16.125 million, which is a decrease of $223,000, or 1 percent below 2015 recorded expenses for FERC Account 903.200. SCE makes an upward adjustment of $368,000 for Customer Growth. SCE also makes an upward adjustment of $333,000 to hire temporary supplemental staff for the CS Re-platform project. This includes $233,000 to hire 8 FTEs as SCE labor staff, as well as $101,000 to hire 5 FTEs as contract services. SCE makes a downward adjustment of $53,000 due to CS Re-Platform benefits. Lastly, SCE makes a downward adjustment of $871,000 due to Operational Excellence savings resulting from increased vendor partnering and streamlining work processes.[686]

ORA recommends $15.792 million, which is $333,000 or 2 percent less than SCE's request. ORA does not oppose SCE's upward adjustment of $368,000 for Customer Growth but ORA opposes the following requests:[687]

5.1.2.1 CS Re-Platform

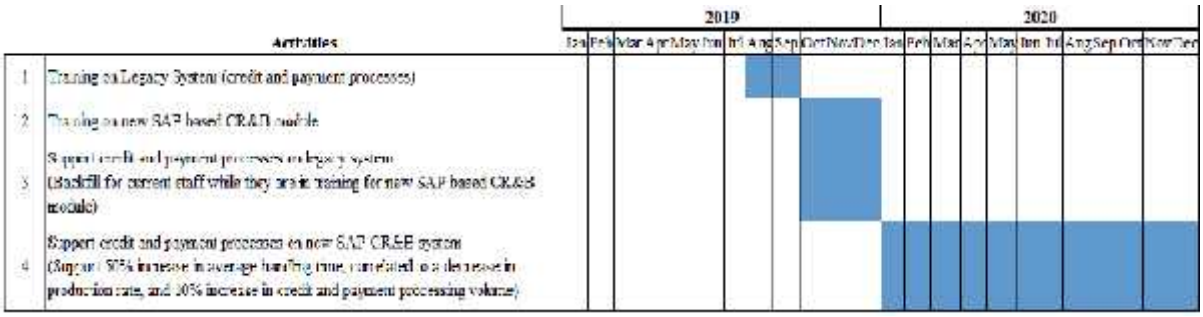
ORA objects to SCE's request for $333,000 to hire temporary, supplemental staff for the CS Re-Platform project. ORA instead recommends that SCE be required to track costs associated with hiring supplemental staff for the CS Re-platform in a memorandum account. A memorandum account will protect ratepayers from the uncertainty associated with whether SCE will execute its CS Re-Platform as planned, versus being delayed.

[686] Ex. SCE-03, p. 87.

[687] Ex. ORA-12, p. 20.

As described in Ex. SCE-04, Vol. 3, SCE plans to implement the CS Re-Platform capitalized software project in 2020 which includes two components: (1) RSO supplemental staff costs and (2) RSO staff augmentation-contractor costs. SCE claims that it needs temporary staff in RSO to maintain the credit, collection and payment processes under the legacy system while SCE staff are trained on the new SAP-based system.[688]

SCE plans to use the supplemental staff for 17 months in a timeline that includes: training on the legacy system (for credit and payment processes) from August to September 2019, training on the new SAP based CR&B module and supporting credit and payment processes on legacy system (backfill for current staff while they are in training for new SAP based CR&B model) from October to December 2019, and supporting credit and payment processes on the new SAP CR&B system from January to December 2020. See table below for a visualization of SCE's proposed timeline.[689]



It is uncertain whether the proposed hiring, training and employment schedule of the supplemental staff will be completed by SCE's proposed timeline of December 2020. If the CS Re-Platform start up timeline is delayed beyond 2020, then the costs will lie outside of the attrition years in this GRC cycle.[690]

Furthermore, the level of supplemental staff hiring being proposed for this group, 8 labor staff and 5 contract services, for a total of 13 supplemental staff, is unprecedented for the Credit

[688] Ex. SCE-03, p. 100.

[689] SCE response to data request ORA-SCE-209-CY3, Q.1.a.

[690] Ex. ORA-12, p. 21.

and Payment Services Group. See below a chart SCE provided on historical recorded supplemental staff levels.[691]

Credit and Payment Services (FERC 903.200) FTE Count - Year End Totals						
Category	2011	2012	2013	2014	2015	2016
EMPLOYEE	78	85	76	72	67	48
SUPPLEMENTAL (Contingent/Temporary)	4	1	0	0	2	8
Grand Total :	82	86	76	72	69	56

As previously discussed, ORA recommends that SCE be required to establish a memorandum account as a method of tracking and recovering these costs. Imposition of a memorandum account will protect ratepayers from the uncertainty associated with the startup of SCE's proposed CS Re-Platform project.[692]

5.1.3 FERC Account 903.800: Customer Contact Center

FERC Account 903.800 captures the costs for SCE's Customer Contact Center (CCC). SCE's CCC is staffed by over 550 Customer Service Representatives (CSRs) and support personnel to respond to customer requests and inquiries.[693]

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 903.800.

FERC Account 903.800
2011-2015 Recorded Expenses
(in Thousands of Dollars ($2015))[694]

FERC Account 903.800	2011	2012	2013	2014	2015
Labor	$38,552	$37,078	$36,468	$34,337	$29,756
Non-Labor	$13,440	$12,834	$12,973	$13,323	$13,701
Total	$51,992	$49,912	$49,441	$47,660	$43,457

[691] SCE response to data request ORA-SCE-221-CY3, Q.1.a.

[692] Ex. ORA-12, p. 22.

[693] Ex. SCE-03, p. 118.

[694] 2011-2015 data from Ex. SCE-3, p. 124.

The following table presents SCE's and ORA's 2018 forecasts for FERC Account 903.800:

FERC Account 903.800
2018 Forecasted Expenses
(in Thousands of Dollars ($2015))

FERC Account 903.800	SCE 2018	ORA 2018	Difference SCE>ORA
Labor	$30,413	$25,846	$4,567
Non-Labor	$15,876	$13,643	$2,233
Total	$46,289	$39,489	$6,800

SCE requests $46.289 million, which is an increase of $2.832 million, or 7 percent, above 2015 recorded expenses for FERC Account 903.800. SCE made an upward adjustment of $980,000 to account for customer growth. SCE made an upward adjustment of $579,000 to account for program changes, which includes $322,000 to hire seven additional FTEs to support CCA activity and $257,000 to handle Time-of-Use (TOU) period adjustment and Default Critical Peak Pricing (CPP) activity.

SCE requests $6.702 million to support the CS Re-Platform project, which includes $6.800 million for supplemental staff training and augmentation, and a reduction of $98,000 in benefits. Specifically, SCE plans on hiring an additional 192 FTEs as supplemental labor to handle incremental calls resulting from the change over to the new system, as well as an additional 131 FTEs for contract services to also handle incremental calls resulting from the change over to the new system.[695]

Lastly, SCE made a downwards adjustment of $5.429 million due to Operational Excellence measures.[696]

ORA recommends $39.489 million, which is $6.8 million or 15 percent less than SCE's request. ORA does not oppose SCE's upwards adjustment to account for customer growth, nor does it object to the upwards adjustment for program changes. However, ORA objects with the following request:

[695] Ex. ORA-12, p. 25.

[696] Ex. SCE-03, p. 132.

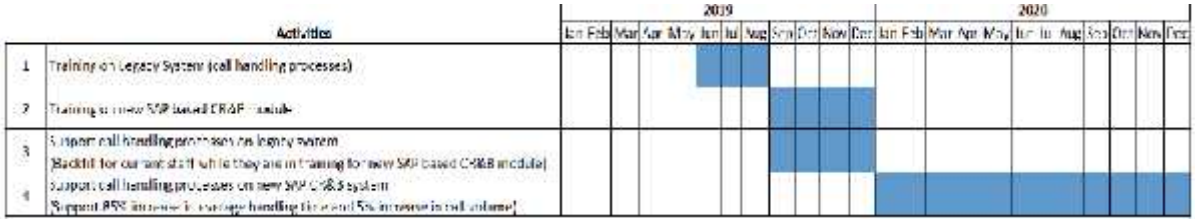
5.1.3.1 CS Re-Platform

ORA objects to SCE's request for $6.8 million to hire temporary, supplemental staff for the CS Re-Platform project. ORA instead recommends that SCE be required to track costs associated with hiring supplemental staff for the CS Re-Platform in a memorandum account.

SCE's requests $6.8 million to hire temporary, supplemental staff for the CS Re-Platform project. This includes 192 FTEs for Labor and 131 FTEs for contract services staff augmentation.

As described in Ex. SCE-04, Vol. 3, SCE plans to implement the Customer Service Re-platform capitalized software project in 2020. SCE anticipates needing the temporary, supplemental staff to do the following: 1) provide pre go-live backfill coverage of existing SCE Call Center staff so that SCE's Call Center staff can train on the new SAP CR&B system and 2) support the post go-live anticipated increase in call volumes and average handle time for CCC processes.[697]

SCE has set forth a 19-month timeline for the supplemental staff that includes: training on the legacy system (for call handling processes) from June to August 2019, training on the new SAP based CR&B module as well as supporting call handling processes on legacy system (backfill for current staff while they are in training for new SAP based CR&B model) from September to December 2019, and supporting credit and payment processes on the new SAP CR&B system from January to December 2020. See the table below for a visualization of SCE's proposed timeline.[698]



ORA opposes SCE's request for $6.702 million in the test year 2018 (and additional amounts in 2019 and 2020) to support the CS Re-Platform project. ORA makes this recommendation because of the uncertainty surrounding whether the proposed hiring, training,

[697] Id.

[698] SCE's response to data request ORA-SCE-209-CY3, Q.1.a.

and employment schedule of the supplemental staff will be on schedule. If the schedule was delayed, the costs will lie beyond the attrition years in this GRC cycle.

The number of supplemental staff that SCE proposes adding would be completely unprecedented. Below is a table of the historical staffing levels for the RSO Billing Services Group.[699] SCE requests an additional 192 FTEs for labor and 131 FTEs in contract services for TY 2018. The table demonstrates that that level of additional labor is completely unprecedented as compared to recent years.

CCC Full-Time, Supplemental, and Contract Employees 2011-2016							
Line No.	**Description**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
1	CCC FTEs	758	742	724	652	530	504
2	CCC Supplemental Employees (contingent/temporary workers)	9	4	6	10	7	4
3	Contract FTE Total	197	205	264	221	237	241
4	Total CCC Full Time/Supplemental Employees and Contract FTEs	964	951	994	883	774	749

As previously discussed, ORA recommends that SCE be required to establish a memorandum account to track the costs of the CS Re-Platform project. SCE should be required to support recovery of the costs booked in the memorandum account after completion of the project and affirmatively show that the expenses were incremental to those costs authorized by the Commission in this rate case.[700]

5.1.4 FERC Account 904: Uncollectible Expense

FERC Account 904 records SCE's expenses for all revenue components of uncollectible customer accounts. Historically, expenses recorded in this account are authorized based on an estimate of the uncollectible expense factor, which is expressed as a percentage of SCE's total revenue. The authorized rate of uncollectible factor is applied to Test Year generation and distribution revenues in the GRC proceeding and is also applied to revenue components litigated in other rate setting proceedings before the California Public Utilities Commission and FERC.[701]

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 904.

[699] SCE's response to data request ORA-SCE-146-CY3, Q.3.b.

[700] Ex. ORA-12, p. 26.

[701] Ex. SCE-03, p. 112.

2011-2016 Recorded / 2018 Forecast
(in Thousands of Dollars ($2015))[702]

Description	2011	2012	2013	2014	2015
Uncollectible factor	0.227%	0.222%	0.222%	0.192%	0.215%

The table here presents SCE's and ORA's 2018 forecasts for FERC Account 904:

Table 12-25
FERC Account 904
2018 Forecasted Expenses
(in Thousands of Dollars ($2015))

FERC Account 904	SCE 2018	ORA 2018	Difference SCE>ORA
Uncollectible factor	0.216%	0.216%	0

SCE requests an uncollectible factor of 0.216%, which is a decrease of 0.001 percent, or 0.5 percent below SCE's 2015 recorded uncollectible factor for FERC Account 904. SCE does not calculate the uncollectible factor through last year's recorded methods unlike the other FERC accounts listed. Rather, SCE calculates its forecast uncollectible factor from the most recent five year recorded expenses (2011-2015) after removing the uncollectible expenses resulting from the Residential Disconnection OIR.[703]

ORA recommends an uncollectible factor of 0.216% for FERC Account 904, which is the same as SCE's forecast.[704]

5.1.5 Business Customer Division

Business Customer Division (BCD) delivers customer services to SCE's non-residential customers including Account Management Services, Technical Services, Energy Education Centers, Customer Choice Services and Economic Development Services. The O&M expenses associated with these activities are recorded in FERC Account 908.600.[705]

[702] 2011-2015 data from Ex. SCE-3, p. 112.

[703] Ex. SCE-03, p. 116.

[704] Ex. ORA-12, p. 28.

[705] Ex. SCE-03, p. 145.

FERC Account 908.600 captures costs for SCE's Business Customer Division including the following activities:

1. **Account Management Services:** provide information and account services to non-residential customers.
2. **Technical Services:** provides technical and specialized expertise to the Account Management Services such as Rate and Data Analysis Services; Field Engineering Services; Special Contract and Tariff Administration Services; Education and Communications and Assistance with Distributed Generation Projects.
3. **Energy Education Centers (EEC):** provides residential, commercial, industrial, and agricultural customers with information regarding energy efficiency, demand response, renewable generation, environmental solutions, electric safety, utility programs, electro-magnetic fields, and power quality. SCE operates one EEC in Irwindale and one in Tulare.
4. **Economic Development Services:** helps to retain, grow and attract commercial and industrial customers.
5. **Consumer Choice Services (CCS):** facilitates Energy Service Provider (ESP) and Community Choice Aggregator (CCA) participation in the Direct Access (DA) and potential CCA markets in SCE's service territory and provides oversight of ESPs' and CCAs' day-to-day interactions with SCE.

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 908.600.

FERC Account 908.600
2011-2015 Recorded Expenses
(in Thousands of Dollars ($2015))[706]

FERC Account 908.600	2011	2012	2013	2014	2015
Labor	$18,232	$16,388	$16,089	$17,121	$18,104
Non-Labor	$6,092	$3,313	$3,935	$3,297	$2,736
Total	$24,324	$19,701	$20,024	$20,418	$20,840

Table 12-27 presents SCE's and ORA's 2018 forecasts for FERC Account 908.600:

[706] 2011-2015 data from Ex. SCE-3, p. 145.

FERC Account 908.600
2018 Forecast Expenses
(in Thousands of Dollars ($2015))

FERC Account 908.600	SCE 2018	ORA 2018	Difference SCE>ORA
Labor	$15,427	$15,427	0
Non-Labor	$3,093	$3,034	$88
Total	$18,520	$18,461	$88

SCE requests $18.52 million, which is a decrease of $2.32 million, or 11 percent below 2015 recorded expenses for FERC Account 908.600. SCE makes this recommendation based on the following adjustments: (1) an upward adjustment of $204,000 to account for customer growth; (2) an upward adjustment of $945,000 for program changes, which includes $558,000 for CCA support and $387,000 for outage communications; (3) a downward adjustment of $270,000 for CS Re-platform benefits and (4) a downward adjustment of $3.2 million due to Operational Excellence measures from refining the assignment of account management resources and increasing self-service options available to customers.[707]

ORA recommends $18.519 million for FERC Account 908.600, which is $88,000 less, or less than <1 percent less than SCE's request. ORA does not oppose the adjustments for customer growth or CCA support. Rather ORA adjusts the following request based on 2016 recorded data:[708]

Outage Communications

With the implementation of the Outage Notification Information (ONI) system in 2014, SCE began providing all residential and non-residential customers with timely notifications related to maintenance and repair outage using the customers' preferred and selected means of communication (i.e., phone, text, email).[709] SCE forecasts an upward adjustment for Outage Communication expenses of $387,000 for TY 2018, which includes the forecast $430,514 for

[707] Ex. SCE-03, pp. 167-169.

[708] Ex. ORA-12, p. 30.

[709] Ex. SCE-03, p. 167.

Electronic Messaging costs and forecast of $102,714 for Dear Neighbor Mailer communications. The Dear Neighbor Mailer program sends letters to customers to alert them of increased traffic, lane, or street closures, noise or other inconveniences associated with SCE working on large construction projects in the area. In 2015, the volume for the Dear Neighbor Mailer program was 51,753 letters at a total cost of $70,877 or per unit cost of $1.370. SCE forecast this volume would increase to 75,000 letters in 2016, with a total cost of $102,714 or a $32,000 increase in Test Year O&M expenses.[710] SCE then forecast that the notification volume and cost levels would remain constant from 2016 through TY 2018.

ORA recommends $87,815 less than SCE's forecast Outage Communications adjustment. ORA asked SCE for the recorded Dear Neighbor program volume and total costs for 2016 and learned that the recorded volume was 24,765 letters and the 2016 recorded cost was just $14,899, thus having a unit cost of just $0.60.[711] ORA accepted SCE's assumption that 2016-2018 Dear Neighbor Mailer volume and costs would remain steady. Therefore, assuming that TY 2018 costs for this program are the same as 2016's recorded costs, there would be a reduction of expenses equivalent to the difference between the forecast costs of $102,714 and the recorded costs of $14,899, which is $87,815.[712]

FERC Account 907.600 captures costs for support activities of SCE's Operating Unit Management and Support function within the senior vice president's office, Business Planning, BCD, and CP&S.[713]

5.2 Customer Service-Capital

CS Capital Expenditures

SCE's capital expenditures for CS consists of CSOD capital requirements and BCD capital requirements. Capital requirements are categorized in three classes of plant: structures and improvements, specialized equipment, and meters. SCE requests capital expenditures of $22.79 million in 2016, $28.04 million in 2017 and $38.84 million for TY 2018.[714]

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[710] Ex. SCE-3 workpapers, Chapter VII-X, p. 96.

[711] SCE response to data request ORA-SCE-150-CY3, Q.1.a.

[712] Ex. ORA-12, p. 31.

[713] Ex. SCE-3, p. 145.

[714] Ex. SCE-03, p. 10.

ORA recommends capital expenditures of $16.328 million in 2016, $28.04 million in 2017, and $38.84 million for TY 2018. The 2016 value was derived from the actual recorded 2016 capital expenditures sent to ORA by SCE in data response document ORA-SCE-108-TXB Q.02 Supplemental Revision 2, and was inputted into the RO model using a prorated calculation based on variance from actual recorded 2016 data for the three classes of plant, respectively. There were no planned cancellations of projects for 2017 and 2018,[715] thus ORA does not dispute SCE's 2017 and 2018 forecast.[716]

For CS Capital Expenditures for 2016 through 2018:

- ORA recommends meter capital expenditures of $13.71 million in 2016, $25.34 million in 2017 and $36.26 million in 2018.
- ORA recommends structures & improvements expenditures of $0.90 million in 2016, $1.85 million in 2017 and $2.04 million in 2018.
- ORA recommends specialized equipment expenditures of $1.73 million in 2016, $0.85 million in 2017 and $0.54 million in 2018.[717]

5.3 CS-Related Other Operating Revenues

Customer Service Operations Division (CSOD) is responsible for assessing the fees to charge individual customers and third parties who receive services that cause SCE to incur additional operational expenses.[718] The revenue received for these services is accounted for as Other Operating Revenues (OOR). These services include service connection charges for the establishment of service and reconnecting service following disconnection for nonpayment of bills, returned check charges to offset costs associated with the processing of checks that are returned from the bank due to insufficient funds, other services associated with Direct Access and Community Choice Aggregation, and other special services.

SCE estimates OOR to be $28.177 million in TY 2018 based on its proposed service fees, compared to $32.255 million in 2015 recorded OOR.

ORA does not object to SCE's forecast of OOR for TY 2018.[719]

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[715] SCE response to data request ORA-SCE-197-CY3, Q.1.b.

[716] Ex. ORA-12, pp. 34-35.

[717] Ex. ORA-12, pp. 2-3.

[718] Ex. SCE-03, p. 211.

[719] Ex. ORA-12, p. 34.

5.4 Customer Service- Additional Issues

Customer Programs & Services

Customer Programs & Services manages the Consumer Affairs, Customer Satisfaction, Marketing Communications & Digital Customer Experience, Product Development and Program Management groups. O&M expenses for these CP&S functions are recorded in FERC Account 905.900.[720]

SCE requests $24.442 million, which is a decrease of $41,000, or less than 1 percent, below 2015 recorded expenses for FERC Account 905.900. SCE's request is the result of the following adjustments: (1) an upward adjustment of $4.44 million in program changes, including $828,000 for a Voice of the Customer program, $1.981 million for a TOU adjustment and default CPP program, $447,000 for DER contract management, $953,000 for renewable tariffs, and $232,000 for new customer programs; (2) a downward adjustment of $4.151 million for operational excellence due to reductions in labor and non-labor marketing costs and (3) a reduction of $330,000 in CS Re-Platform benefits.[721]

The table below presents the recorded adjusted expenses for 2011 through 2015 for FERC Account 905.900.

FERC Account 905.900
2011-2015 Recorded Expenses
(in Thousands of Dollars ($2015))[722]

FERC Account 905.900	2011	2012	2013	2014	2015
Labor	$12,492	$11,326	$11,802	$12,070	$10,865
Non-Labor	$14,985	$13,269	$18,515	$14,277	$13,618
Total	$27,477	$24,595	$30,317	$26,347	$24,483

The table presents SCE's and ORA's 2018 forecasts for FERC Account 905.900:

[720] Ex. SCE-03, p. 202.

[721] Ex. ORA-12, p. 33.

[722] 2011-2015 data from Ex. SCE-3, p. 178.

FERC Account 905.900
2018 Forecasted Expenses
(in Thousands of Dollars ($2015))

FERC Account 905.900	SCE 2018	ORA 2018	Difference SCE>ORA
Labor	$10,717	$10,717	0
Non-Labor	$13,725	$13,725	0
Total	$24,442	$24,442	0

ORA recommends $24.442 million for FERC Account 905.900, which is the same as SCE's forecast.[723]

6. INFORMATION TECHNOLOGY

Informational Technology (IT) expenses are costs typically associated with the operations and maintenance of SCE's IT services. IT capital expenditures are costs typically associated with management of IT infrastructure, storage media, communications links, operating systems, application software, and a variety of personal computing, and communications devices used by employees.[724]

6.1 Information Technology – O&M and Hardware

ORA does not dispute SCE's Hardware expenditures requests for 2017 or 2018. ORA recommends adopting SCE's recorded 2016 expenditures amount of $100.1 million as SCE's Hardware expenditures for 2016.

In the direct testimony submitted with its Application, SCE requested $267.5 million in expenses for IT services.[725] ORA recommends a lower O&M forecast for 2018 of $244.5 million, which is $37.7 million, or 15%, lower than SCE's request of $265 million.[726] ORA's O&M forecast for 2018 is $229.7 million with the expected savings of $14.7 million from Operational Excellence, as forecast by SCE.

[723] Ex. ORA-12, p. 34.

[724] Ex. ORA-13, p. 1.

[725] Ex. SCE-04, Vol. 1, p. 18.

[726] Ex. ORA-13.

SCE's IT Services O&M request is broken down into seven categories. The main increases are in three categories: (1) Grid Services, (2) Business Integration & Delivery, and (3) Services Management Office & Operations – Hardware and Software License Maintenance.[727] ORA's recommendations for these three areas are described below.

Services Management Office and Operations – Hardware/ Software License & Maintenance Expense

SCE requests $71.2 million in expenses for the work activities tracked under Hardware/Software License & Maintenance.[728] This amount is $13.3 million, or 23%, higher than the 2015 recorded amount of $57.9 million. SCE states that the expenses are required to maintain SCE's IT hardware and software assets through license and maintenance agreements.[729] ORA recommends the Commission adopt the 2016 recorded expense of $62.8 million for 2018. This amount is lower than SCE's request of $71.2 million, but greater than the base year amount by nearly $4.9 million.

Hardware maintenance includes costs for "break/fix for IT equipment (e.g., servers and storage)" no longer supported by the manufacturer and for agreements to support destruction of storage media consistent with cyber security standards, NERC CIP, and other confidential data.[730] Software maintenance includes costs for software support agreements that give SCE access to break/fix support, service patches, and upgrades to software managed by IT.[731]

ORA's adjustment is based on a review of SCE's forecasting method and the reasons that SCE provided as justification for the increase. SCE says that, "[t]he increase is primarily due to several software support agreements from capital purchases made in 2011 that are shifting from capital to O&M expense including Netapp, Teradata, Oracle, and VMWare software applications. The increase also includes new costs for software-as-a-service agreements such as

[727] Ex. ORA-13, p. 6. ORA does not oppose SCE's requests for Enterprise Architecture and Strategy; Cybersecurity and Compliance; Grid Services Network Rents; Service Management Office and Operations Expenses. (Ex. ORA-13, pp. 6, 9, and 15.)

[728] Ex. SCE-04, Vol. 1, p. 29.

[729] Ex. SCE-04, Vol. 1, p. 26.

[730] Ex. SCE-04, Vol. 1, p. 27.

[731] Ex. SCE-04, Vol. 1, p. 27.

Microsoft Azure."[732] SCE also claims that it experienced vendor price increases and included these in the forecast.[733]

SCE used its last recorded year (2015) expense, $57.9 million, as the base forecast. SCE then forecasts an increase of $102,000 for labor and $13.2 million for non-labor costs. SCE's justification is that, "…the forecast non-labor costs from this account are based on the unique license and maintenance costs associated with each software and hardware item forecast in this account."[734]

ORA disagrees with SCE's methodology and recommends $62.8 million for 2018. The main reason is that SCE has not provided adequate support for the significant increase of 23% in costs for this work account.[735]

SCE forecasts a stable expense level from 2016-2018 at approximately $71 million each year. SCE's rationale for the requested increase each year is the same, namely that capitalized software purchased with prepaid license and maintenance agreements end after a five-year period and these costs will shift from capital expenditures to O&M expenses. For 2018, SCE claims that, "The increase is primarily due to several software support agreements from capital purchases made in 2011 that are shifting from capital to O&M expense…"

SCE provided a list of the number of software projects that were capitalized each year, and the annual costs as part of prepaid licenses and maintenance agreements.[736] The information was in an Excel spreadsheet that contained a long list of projects, but had no dates associated with them.[737]

ORA, therefore, asked SCE to provide the annual expenses from 2011-2016 attributed to licenses rolling off the five-year maintenance from capital to O&M. SCE was able to provide the annual costs for 2013-2016,[738] and from SCE's response, it appears that the O&M cost level of software licenses coming off the five-year cycle is stable. In fact, the expenses show a

[732] Ex. SCE-04, Vol. 1, p. 31.

[733] Ex. SCE-04, Vol. 1, p. 31.

[734] Ex. ORA-13, p. 17, citing Ex. SCE-04, Vol.1, workpapers, p. 74.

[735] Ex. ORA-13, p. 18.

[736] Ex. ORA-13-WP, p. 9, SCE response to ORA-SCE-55-DAO, Q.1.

[737] Ex. ORA-13-WP, p. 9, SCE response to ORA-SCE-55-DAO, Q.1.

[738] Ex. ORA-13-WP, p. 10, SCE response to ORA-SCE-55-DAO, Q.2.

decrease from 2015 to 2016. ORA could not evaluate the projects that SCE claimed were purchased in 2011 that will shift to O&M expenses in 2018 leading to the 23% increase in SCE's estimate since SCE did not provide that information.[739]

ORA, therefore, recommends the Commission adopt the 2016 recorded amount of $62.8 million for SCE's software license costs from capital to O&M.[740]

In Rebuttal, SCE says it "… expected ORA… to have reviewed each license and maintenance agreement provided them, and evaluated the reasonableness of each."[741] SCE's expectations notwithstanding, it is not ORA's responsibility to bolster SCE's inadequate showing when SCE does not provide information in direct testimony. If SCE had evidence that "each license and maintenance agreement" was reasonable, SCE should have provided it when it submitted its application or when asked for the information from 2011 on. SCE did not do so.

ORA continues to recommend the Commission adopt SCE's 2016 recorded amount of $62.8 million for SCE's Hardware/Software License & Maintenance Expense.

Grid Services

SCE requests $44.4 million in expenses for Grid Services. In 2015, SCE spent $29.5 million in this work category. SCE's request is an increase of $14.9 million, the equivalent of a 51% increase. SCE's 2018 forecast is based on using the recorded 2015 base year labor and non-labor expenses amount of $29.5 million plus incremental expenses to support Grid Modernization projects.[742]

ORA recommends adopting the 2015 recorded expenses of $29.5 million for 2018. ORA does not object to SCE's use of last recorded year as the base in estimating its forecast. ORA disagrees with the inclusion of the incremental costs for Grid Modernization because SCE's forecast is premature and inadequately supported. SCE's incremental request, an increase of $2.5 million, or 12%, in labor expenses and an increase of $12.3 million, or 150%, in non-labor expenses,[743] should be rejected.

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[739] Ex. ORA-13, p. 18.

[740] Ex. ORA-13, p. 18.

[741] Ex. SCE-20, Vol. 1, p. 9, lines 18-19.

[742] Ex. SCE-04, Vol. 1, pp. 60-61.

[743] Ex. SCE-04, Vol. 1, pp. 60-61.

The increase in labor expenses for the Test Year to support Grid Modernization is attributable to SCE's request for additional support for various Grid Modernization projects including: (1) Field Area Network (FAN), Wide Area Network (Fiber), Grid Management System (GMS) and Common Substation Platform (CSP).[744] For the non-labor expenses, SCE claims that the surge in expenses is due to anticipated repairs and replacements for the additional networking and telecommunication equipment and technologies required across various Grid Modernization projects identified above.[745]

According to SCE, the Grid Services group manages the 24/7 operational functions to support the electric grid, which comprises electric and generation control systems, grid communication network, gird data center, grid and telecommunication operation centers and grid security operations.[746] The activities performed by this group include designing, engineering, installing, operating, monitoring, repairing, and maintaining the voice, data and satellite networks for SCE.[747]

SCE's justification for the requested increase is its claim that repairs and replacements for the additional networking and telecommunication equipment and technologies associated with various Grid Modernization projects, such as FAN, Fiber, GMS and CSP are necessary.

ORA asked SCE to provide support for its non-labor forecast. SCE responded that, "Due to the fact that we are in the early planning stages of Grid Modernization, we are unable to provide the detailed estimates for repairs at this point."[748] SCE also did not provide adequate support for the projected equipment and hardware replacement costs.[749] Yet SCE proposes exact labor and non-labor amounts it anticipates for 2018-2020, (a total of $44.5 million, an average of $14.9 million per year[750]) without the details to support them. SCE supplemented its response at a later date, however ORA is still not convinced that the requested funding is reasonable. Although SCE's response lists the general assumptions used to derive its forecast, these

[744] Ex. SCE-04, Vol. 1, p. 60.

[745] Ex. SCE-04, Vol. 1, p. 60.

[746] Ex. SCE-04, Vol. 1, p. 56.

[747] Ex. SCE-04, Vol. 1, p. 56.

[748] Ex. ORA-13-WP, p. 7 (SCE response to data request ORA-SCE-041-DAO, Q.1.)

[749] Ex. ORA-13-WP, p. 7 (SCE response to data request ORA-SCE-041-DAO, Q.1.)

[750] Ex. SCE-04, Vol. 1, p. 61.

assumptions do not support SCE's proposal. SCE claims in testimony that repairs and replacements of additional networking and telecommunication equipment technologies are required to support various Grid Modernization projects, but SCE did not provide any support for the level of funding requested. The anticipated level of work activities and funding associated with anticipated repairs and replacements of equipment to support Grid Modernization projects at this time is unreliable. SCE's support for this request amounts to an Excel file with spreadsheets populated with numbers that add up to the amount of requested funding in its forecast. It is unreasonable to require ratepayers to fund future work activities that are premature and not adequately supported.

SCE's entire request should be rejected. Any estimates regarding Grid Modernization-related projects are premature. Grid Modernization initiatives are currently being addressed in the Distribution Resource Planning (DRP) proceeding per AB 327 and the Commission's Order Instituting Rulemaking (R.)14-08-013. DRP-related expenditures should be consistent with AB 327, and this GRC should not prejudge the outcome of the DRP proceeding.[751]

In SCE's original testimony, SCE included $71,000 in expenses incurred by Grid Services to provide a dedicated support team for SCE's San Onofre Nuclear Generating Station in the 2015 base year labor expenses.[752] Subsequently SCE removed these costs in its November 17th Errata submission.[753] ORA agrees with this change.

SCE's request of $14.9 million in expenses for incremental labor and non-labor costs to support Grid Modernization should be rejected in this proceeding. Any costs associated with SONGS should also be rejected.[754]

ORA recommends that all projects supporting Grid Modernization investments/initiative be tracked in a memorandum account. Any forecast of expenditures at this time is premature.

ORA's 2018 forecast for Grid Services (FERC Account 920/921) excludes the $14.9 million in incremental costs SCE requests for projects supporting Grid Modernization. A

[751] Ex. ORA-9 presents ORA's analysis and recommendations regarding SCE's Grid Modernization proposals in this GRC.

[752] Ex. SCE-04, Vol. 1, p. 58.

[753] Ex. ORA-13-WP, p. 7 (SCE response to data request ORA-SCE-037-DAO, Q.1.)

[754] Ex. ORA-13, p. 9.

forecast of expenditures at this time is premature. ORA recommends the Commission adopt ORA's forecast of $44.375 million.[755]

Business Integration and Delivery

SCE requests $46.6 million in expenses for Business Integration and Delivery (BID).[756] In 2015 SCE recorded $32.0 million in expenses for this work category. SCE's request for $14.6 million, or 46%, above the base year expenses is based on an increase of $3 million in labor and $11.6 million in non-labor costs. ORA recommends using the 2015 base year and an increase of $167,000 for one incremental project resulting in a 2018 forecast amount of $32.1 million, with $15.4 million in labor and $16.7 million in non-labor expenses.

The BID organization is responsible for leading the technology planning and delivery services for SCE's internal Operating Units.[757] According to SCE, BID identifies, prioritizes, and oversees system enhancements and investments to meet customer and regulatory needs, financial and compliance objectives and to support the implementation of IT services.[758]

SCE claims the increase in labor costs is for the BID organization to support three new upcoming large projects: (1) Customer Service Re-Platform, (2) New Grid Planning and Analytics Software and (3) Grid Modernization Applications.[759] SCE says the increase in non-labor costs is for third-party service providers to provide expertise in supporting delivery activities for software projects, and to assist SCE in successful planning and implementation of the following projects: (1) Customer Service Re-Platform, (2) New Grid Planning and Analytics Software, (3) Grid Modernization Applications and (4) HR Platform Modernization.[760]

ORA's forecast is $32.1 million for Business Integration and Delivery, with $15.4 million in labor and $16.7 million in non-labor expenses. ORA's forecast uses the 2015 recorded labor and non-labor expenses, plus the $167,000 for Digital Experience SAS, and zero

[755] Ex. ORA-13, p. 3, Table 13-1.

[756] Ex. SCE-04, Vol. 1, p. 40.

[757] Ex. SCE-04, Vol. 1, p. 35.

[758] Ex. SCE-04, Vol. 1, pp. 35-36.

[759] Ex. SCE-04, Vol. 1, p. 42.

[760] Ex. SCE-04, Vol.1, pp. 43-44.

incremental funding for (1) CS Re-Platform, (2) New Grid Planning and Analytics, (3) Grid Modernization and (4) HR Platform Modernization.[761]

To conform to the Common Briefing Outline, ORA's recommendations for HR Platform Modernization projects are described below. ORA's recommendations for the New Grid Planning and Analytics, and Grid Modernization are described below in Section 6.2. ORA's forecasts for the CS Re-Platform project are described below in Section 6.3.

Human Resources Platform Modernization

SCE requests $2.9 million in expenses in 2018 for the Business Integration and Delivery organization to support the replacement of its existing primary SAP Enterprise Resource Planning Human Capital Management system,[762] and consolidate approximately 70 existing legacy systems into a cloud-based human resource application.[763] The new project is called the Human Resource (HR) Platform Modernization project.[764] SCE states that this new project will improve its HR business processes and modernize HR systems.[765] ORA recommends the Commission reject SCE's request for ratepayer funding.[766]

ORA asked SCE to provide the annual O&M expenses incurred from 2011-2015 to support the existing SAP Enterprise Resource Planning Human Capital Management system. SCE responded that it "…does not track or record the cost in the manner that is being requested." According to SCE, the "existing HR legacy application costs were approximately $20 million from 2011-2015."[767]

Based on SCE's response, it is not possible for ORA to determine the amount of O&M expense recorded in the base year that would be available for the requested project.

In Rebuttal, SCE revised the scope of the HR Platform Modernization project saying that this was the "result of additional analysis."[768] According to SCE, as a result of this "additional

[761] Ex. ORA-13, p. 11.

[762] Ex. SCE-4, Vol. 1, p. 42, Table III-2.

[763] Ex. SCE-04, Vol. 1, p. 44.

[764] Ex. SCE-04, Vol. 1, p. 44.

[765] Ex. SCE-04, Vol. 1, p. 44.

[766] Ex. ORA-13, p. 14.

[767] Ex. ORA-13-WP, p. 8 (SCE response to data request ORA-SCE-045-DAO, Q.3).

[768] Ex. SCE-20, Vol. 1, lines 12-13.

analysis," SCE "determined the HR Platform Modernization project would have to be deployed at the same time as the Customer Service Re-Platform and Enterprise Core Refresh."[769] When asked if that meant that, if the Customer Service Re-Platform project is delayed, the HR Modernization project would also be delayed, SCE's witness responded that "No…. we would still be implementing the HR Re-Platform Modernization project."[770]

ORA recommends the Commission adopt the logical interpretation of SCE's Rebuttal as written: a delay in the Customer Service Re-Platform will mean a delay in the HR Modernization program. Testimony of an SCE witness who SCE hired as an expert confirms the likelihood of a delay in the CS Re-Platform project:

> …there is a -- depending upon how it [the Customer Service Re-Platform project] is managed, I think there is a decent risk of it going past a schedule. It is a fairly large SAP project on the order of $200 million in three years. The typical mitigation strategy in such cases is to reduce scope for the initial production, which is how you try to manage both the contingency cost and the schedule itself…."[771]

When asked what he meant by a "decent risk of it going past schedule," the SCE witness said that:

> …when you have an issue of a risk with a contingency level, there is a good chance that this is going to be a schedule slip, unless, as I say, you choose to mitigate by reducing the scope of the project in order to bring it in by a specific deadline.[772]

ORA continues to recommend the Commission reject SCE's request of $2.9 million for the HR Modernization project. If, as seems likely, the CS Re-Platform project is delayed, the HR Modernization project, tied to the CS Re-Platform projects is likely to be delayed too. There is no reason to make ratepayers pay these extra costs in the test year.

In past GRCs, SCE has been authorized annual O&M expenses to support the current SAP Enterprise Resource Planning Human Capital Management system. Since this system will

[769] Ex. SCE-20, Vol. 1, lines 19-23.

[770] 7 RT 787: 6-13, Kelly/SCE.

[771] 8 RT 890: 6-14, Webster/SCE.

[772] 8 RT 891: 10-16, Webster/SCE.

be replaced by the new HR Platform Modernization project, there should be adequate expenses embedded in 2015 recorded data, which SCE used as a basis for forecasting the 2018 expenses, to implement the new HR Platform Modernization.[773]

Funding has been made available to SCE in previous GRCs to support its HR system. SCE has not shown that level of ratepayer funding to be insufficient. SCE's request for additional ratepayer funding in this GRC should be rejected.

6.2 Information Technology – Capitalized Software

Contingency Costs in Capitalized Software Projects

SCE says that, as part of its capitalized software cost estimation process, it incorporates amounts for contingency to "account for uncertainties and unknowns throughout the design and implementation of projects."[774]

IT Capitalized software projects provide support to SCE's Operating Units and to enterprise level systems for SCE.[775] In its Application, SCE requests $809.1 million in capital expenditures from 2016-2020 for capitalized software projects.[776] Of that, SCE requests $151.7 million in capital expenditures for Capitalized Software projects in 2016, $213.4 million in 2017 and $202.9 million in 2018.[777]

ORA recommends the Commission adopt SCE's 2016 recorded capital expenditures amount of $164.3 million for 2016. ORA also recommends the Commission adopt $142.2 million for 2017 and $138.8 million for 2018, and deny SCE's request for a 20% contingency allowance.[778]

ORA reviewed 15 projects from the Capitalized Software forecasts SCE set forth in direct testimony,[779] and separately identified the contingency costs SCE assigned to the projects.

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[773] Ex. ORA-13, p. 14.

[774] Ex. SCE-20, Vol. 1, p. 24.

[775] Ex. SCE-04, Vol. 2, p. 1.

[776] Ex. SCE-04, Vol. 2, p. 1.

[777] Ex. SCE-04, Vol. 2, p. 1.

[778] Ex. ORA-13, p. 20.

[779] The projects ORA reviewed are (1) Operating System Software, (2) SCADA Cybersecurity, (3) Grid Modernization Cyber Security, (4) Data Warehouse Consolidation, (5) Digital Customer Self Service, (6) Work Management, (7) Vegetation Management, (8) Energy Management System Refresh, (9) Comprehensive Situational Awareness for Transmission, (10) Centralized Remedial Action Scheme, (11)

A few projects did not have any contingency costs as part of the project estimates. When ORA reviewed SCE's direct testimony, there were 41 projects with contingency costs above $300,000. The contingency costs of these projects totaled $47.2 million, based on the 20% contingency percentage SCE used.[780]

Based on the cost estimation worksheets SCE provided as support for its direct testimony, approximately 100 projects were listed under the Capitalized Software category.[781] In the 2015 GRC, SCE used a range of contingency percentages for its capitalized software requests, from 0% to 35%.[782] SCE provided a listing of its capitalized software projects in the 2015 GRC. The recorded spending for several projects is significantly below the authorized amounts and for some projects, there was zero spending recorded.[783]

Vegetation Management is one example. In the TY 2015 GRC, the Commission authorized $5 million for the Vegetation Management project, which included 35% in contingency. SCE spent zero on this project during the 2012-2015 period.[784] The Work Management Dashboard project is another example where SCE was authorized $3.6 million, including a 35% contingency, and the utility spent zero during the 2015 GRC period.[785] For the Outage Management System Refresh, SCE was authorized $6.7 million, which included a 35% contingency, and recorded $3 million in expenditures during the 2012-2015 timeframe.[786] These examples show that SCE has overestimated its contingency cost element in its 2015 GRC forecast.[787]

Grid Interconnection Processing Tool, (12) Grid Analytics Application, (13) Long-Term Planning Tools, (14) Grid Connectivity Model, and (15) Enterprise Content Management. (Ex. ORA-13, p. 21).

[780] Ex. ORA-13, p. 22.

[781] Ex. ORA-13-WP, p. 1 (SCE response to ORA-SCE-Verbal-001, in which ORA requested "the working spreadsheets that support SCE's testimony and workpapers.") In the working spreadsheets SCE provided, there were some projects with a zero percent contingency, but included contingency dollars in the project total. SCE "corrected" that information in June 2016. This correction had the effect of reducing the number of projects with zero contingencies. (7 RT 797: lines 9-28, Kelly/SCE.)

[782] Ex. ORA-13-WP, p. 54 (SCE response to data request, ORA-SCE-080-DAO, Q.2).

[783] Ex. ORA-13, p. 23.

[784] Ex. SCE-04, p. 95.

[785] Ex. SCE-04, Vol. 2, p. 84.

[786] Ex. SCE-04, Vol. 2, p. 138.

[787] Ex. ORA-13, p. 23.

The projects identified in ORA's testimony are in addition to other capitalized software projects authorized in the 2015 GRC where SCE underspent what it was allowed to collect from ratepayers, but still collected a high level of additional contingency costs. [788] SCE identified six projects, with contingency percentages ranging from 15%-25%, to support its request to add 24% in contingency costs to its proposed Customer Service Re-Platform project. Five of the six projects, were completed under the forecast capital budget and without the use of contingency funding.[789] The sixth project is not scheduled to be implemented until 2017, so whether SCE will need the contingency funding is unknown at this time.[790]

SCE's recorded spending confirms that various proposed projects have come in under budget necessitating no ratepayer funded contingencies.[791]

ORA asked SCE to explain how it determined that the addition of a 20% contingency to each capitalized software project is necessary.[792] SCE responded, "[t]o estimate our contingency, we have used expert judgment, along with the recommendations provided by these resources, to develop guidelines of contingency to use for preliminary project estimates…The use of a 20% contingency on project estimations is also in alignment with SCE's IT and Finance governance processes."[793]

SCE provided a document from the Department of Energy (DOE) as a source of support, claiming that DOE recommends contingency rates of up to 50% during the early stages of projects.[794] According to this document, the 50% that SCE referred to is for projects that are identified as "Experimental/Special Conditions."[795] Based on ORA's review of SCE's testimony and workpapers, there is no project designated as "Experimental/Special Conditions."[796]

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[788] Ex.ORA-13, p. 40 et seq.

[789] Ex. ORA-13-WP, p. 4 (SCE response to data request ORA-SCE-032-DAO, Q.2).

[790] Ex. ORA-13-WP, p. 4 (SCE response to data request ORA-SCE-032-DAO, Q.2).

[791] Ex. ORA-13, pp. 23-25.

[792] Ex. ORA-13-WP, p. 39 (SCE response to data request ORA-SCE-080, Q.1.

[793] Ex. ORA-13-WP, p. 39 (SCE response to data request ORA-SCE-080, Q.1(a)).

[794] Ex. ORA-13-WP, p. 39 (SCE response to data request ORA-SCE-080, Q.1(a)).

[795] Ex. ORA-13-WP, p. 39 (SCE response to data request ORA-SCE-080, Q.1(a)), Att. DOE.pdf, "Chapter 11, Contingency," p. 3.

[796] Ex. ORA-13, pp. 24-24.

According to the documents SCE used as support for its request, "Expert judgment techniques involve consulting with software cost estimation expert or a group of the experts to use their experience and understanding of the proposed project to arrive at an estimate of its cost…a group consensus technique, Delphi technique, is the best way to be used."[797] Based on ORA's review, SCE did not use the Delphi technique; offering instead only a statement that "expert judgment was used."[798]

SCE also cited the International Journal of Computer Science & Applications, the Journal of Emerging Trends in Computing and Information Sciences, and the University of Calgary, all of which say that the Delphi technique is the best technique for the expert judgment method.[799] The Delphi technique involves using several steps, as shown below:

- Coordinator presents each expert with a specification and an estimation form.
- Experts fill out forms anonymously.
- Coordinator calls a group meeting in which the experts discuss estimation issues with the coordinator and each other.
- Coordinator prepares and distributes a summary of the estimation on an iteration form.
- Coordinator calls a group meeting, specially focusing on having the experts discuss points where their estimates varied widely.
- Experts fill out forms, again anonymously, and steps 4 and 6 are iterated for as many rounds as appropriate.

The document from the Journal of Emerging Trends in Computing and Information Sciences included an example of using the Delphi technique. In that example, 8 experts contributed and final convergence was determined after passing 4 stages.[800] Using the Delphi technique to estimate the total project costs, which includes contingency amounts, would be consistent with industry best practices.[801]

[797] Ex. ORA-13-WP, p. 11 (SCE response to data request ORA-SCE-DAO 73, Q. 6(a) Attachment 1, "A comparison of software cost estimation methods—published May 2012.pdf").

[798] Ex. ORA-13, pp. 24-25.

[799] Ex. ORA-13, p. 25.

[800] Ex. ORA-13, p. 26, Figure 13-1.

[801] Ex. ORA-13, p. 26.

SCE did not mention the Delphi technique in its direct testimony, workpapers or responses to ORA data requests for support of SCE's capitalized software requests. In Rebuttal, SCE mentioned the Delphi technique apparently because "ORA asserts that the documents assert the Delphi method to be the best practice."[802]

SCE offers no evidence that the Delphi method is ***not*** the best practice. Instead, SCE says that "[w]hile SCE may not use the entirety of the Delphi method, we employ the main tenets of it."[803] And then SCE goes on to say that it has peer reviews with "several sessions" before final cost estimations are approved.[804] This is hardly the impartial, structured process the Delphi method recommends.

In Rebuttal, SCE refers, once again, to reliance on its own "….expert judgment and predetermined guidelines to support its development of project contingency."[805] Attached to its Rebuttal Testimony, are copies of the "predetermined guidelines" SCE relied on.[806] They are from 1997 and 2008. If there are more recent guidelines, SCE evidently did not consult them.

Ratepayer funding of contingencies has been a subject of interest to the Commission in many proceedings. In PG&E's application to increase rates for 2014-2016 (A. 12-11-009, PG&E 2014 GRC), the utility requested a contingency allowance of $8.5 million for two projects. The Commission denied PG&E's request stating the utility had not justified the need for contingency funding. In its decision, the Commission said:

> We reduce PG&E's MWC GF forecast of mapping and records collection, however, to remove $1.3 million in contingency expense. PG&E has not identified any unusually difficult factors in forecasting that warrant burdening ratepayers with funding of the $1.3 million contingency amount for this program. (p. 42).
>
> We also reduce PG&E's forecast by $7.2 million for a contingency allowance, as proposed by TURN. PG&E identifies nothing particularly unusual or complex about cost estimations for the Gas

[802] Ex. SCE-20, Vol. 1, p. 26.

[803] Ex. SCE-20, Vol. 1, p. 26.

[804] Ex. SCE-20, Vol. 1, p. 26, lines 16-17.

[805] Ex. SCE-20, Vol. 1, p. 25.

[806] 7 RT 799-800, Kelly/SCE.

Training Center that would justify the need for ratepayers to cover a contingency amount of $7.2 million.[807]

In this GRC, SCE has not adequately supported its request for a 20% contingency addition to its software project estimates. ORA recognizes that a certain amount of contingency may be needed to cover unknown risks to a project, and recommends adding a 10% contingency cost, or $23.6 million, for the proposed software projects. As a result, ORA's forecast of contingency-related costs for 2017 and 2018 is $23.6 million lower than SCE's request. This amount is 50% lower than SCE's request of $47.2 million in contingency expenditures, which is included as part of its capitalized software estimates.[808]

SCADA Cyber Security

SCE requests $26.8 million for 2016, $36.2 million for 2017 and $36.4 million for 2018 in capital expenditures for SCADA[809] Cyber Security.[810] ORA recommends adopting the 2016 recorded expenditures of $17.1 million instead of SCE's forecast of $26.8 million as the 2016 forecast. ORA accepts and agrees to SCE's entire SCADA Cyber Security forecasts of $36.2 million in 2017 and $36.4 million in 2018.[811]

Data Warehouse Consolidation

SCE requests $9.400 million for 2016, $4.700 million for 2017 and $2.000 million for 2018 in capital expenditures for Data Warehouse Consolidation. ORA accepts SCE's forecasts for 2017 and 2018. For 2016, however, ORA recommends the Commission adopt the 2016 recorded amount of $7.250 million as the 2016 forecast.[812]

Grid Modernization Cyber Security

SCE requests $5.280 million for 2016, $16.190 million for 2017 and $24.440 million for 2018 in capital expenditures for Grid Modernization Cyber Security.

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[807] D.14-08-032, p. 126.

[808] Ex. ORA-13, p. 27.

[809] SCADA stands for Supervisory Control and Data Acquisition.

[810] *See* ORA-13, p. 28, footnote 69, citing Ex. SCE-04, Vol. 2 workpapers Book A, pp.114, 126, 137 and 140.

[811] Ex. ORA-13, p. 28.

[812] Ex. ORA-13, p. 29.

In Ex. ORA-9, Section III (C), ORA recommends all costs related to Grid Modernization be tracked in a memorandum account.[813] As such, the ORA recommendation for this rate case is zero dollars for Grid Modernization Cyber Security.

Digital Customer Self Service

SCE requests $3.100 million for 2016, $7.500 million for 2017, and $4.000 million for 2018 in capital expenditures for Digital Customer Self Service.[814] In 2016 SCE spent $2.955 million on projects under this work category, which ORA proposes as its 2016 forecast. ORA does not oppose with SCE's request for this work category for 2017 and 2018.[815]

Work Management Solutions

SCE tracks its Work Management Solutions activities under Transmission and Distribution Software Projects. For this work category SCE requests $1.8 million for 2016, $6.0 million for 2017 and $6.2 million for 2018.[816] ORA does not dispute SCE's requests for 2017 and 2018. ORA recommends adopting the 2016 recorded expenditures amount of $2.464 million as the 2016 forecast.[817]

Vegetation Management

SCE requests $2.0 million for 2016 and $5.7 million for 2017 for software tools recorded under Vegetation Management.[818] SCE spent $916,000 on this work category in 2016.

According to SCE, the work activities captured under Vegetation Management include tracking and reporting the quality of its contractors' performance and prioritizing work to help expedite the removal of potentially dangerous trees and to comply with requirements from federal, state, local and environmental agencies.[819]

In the 2015 GRC, the Commission authorized $9.7 million for 2014-2016.[820]

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[813] Ex. ORA-13, p. 29. *See* also Section 4.10 of this Opening Brief.

[814] Ex. ORA-13, p. 30, footnote 71, citing Ex. SCE-04, Vol. 2 workpapers, Book B, p. 10.

[815] Ex. ORA-13, p. 30.

[816] Ex. SCE-04, Vol. 2, p. 75.

[817] Ex. ORA-13, p. 30.

[818] Ex. SCE-04, Vol. 2, p. 95.

[819] Ex. SCE-04, Vol. 2, p. 96.

[820] Ex. SCE-04, Vol. 2, p. 95.

As of the end of 2016, SCE has spent only $916,000 of the authorized amount. In this GRC, SCE requests $5.7 million for 2017 and $2 million for 2016; however it spent only $916,000.

This request should be rejected because SCE was previously authorized $9.7 million in the 2015 GRC and the utility deferred implementing the software project that was authorized. Ratepayers did not receive any benefits from completion of the originally anticipated project. SCE has not fully supported its new 2017 request for an additional $5.7 million. ORA recommends the Commission adopt $916,000 as the 2016 forecast and zero dollars for 2017.[821]

Energy Management System Refresh

SCE requests $6.21 million for 2016, $7.220 million for 2017 and $2.67 million for 2018 to refresh the Energy Management System because the system is aging and the vendor will not support the current version after 2017.[822] ORA does not dispute SCE's proposed funding for the EMS Refresh for 2017 and 2018. However, ORA recommends the Commission adopt the 2016 recorded amount of $4.507 million instead of SCE's 2016 forecast.[823]

Comprehensive Situational Awareness for Transmission (CSAT)

SCE requests $2.0 million for 2017 and $4.00 million for 2018 for the Comprehensive Situational Awareness for Transmission (CSAT) projects.[824] In the 2015 GRC, the Commission authorized $13.1 million for this project, which was then called the Advanced Phasor Analytics project.[825] This project was delayed and now SCE has increased the scope of the original project leading to an increase in costs for 2017-2020. ORA objects to the requested increase in expenditures for 2017 and 2018.

In 2014 and 2015, SCE did not use any authorized funding on this project.[826] According to SCE, it "did not launch the Phasor Analytics project as proposed in our 2015 GRC Application. The delay in the CSAT project launch was a result of the extended deployment and stabilization of the Phasor project."[827]

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[821] Ex. ORA-13, pp. 31-32.

[822] Ex. SCE-04, Vol. 2, p. 136.

[823] Ex. ORA-13, p. 32.

[824] Ex. SCE-04, Vol. 2, p. 110.

[825] Ex. SCE-04, Vol. 2, p. 110.

[826] Ex. SCE-04, Vol. 2, p. 110.

[827] Ex. SCE-04, Vol. 2, p. 111.

The delay in project start means that SCE received $13.1 million in rates that the Commission authorized for this project in SCE's 2015 GRC,[828] but ratepayers did not receive any benefits from completion of the originally anticipated project. In this GRC, SCE has simply changed the project name and revised the scope of this project.

The 2015 GRC authorized $13 million in ratepayer funding for SCE to implement the Phasor project. SCE now requests that ratepayers fund this project again; $6 million for the CSAT project for 2017 and 2018 in this rate case.

SCE has not justified an additional $6 million to implement the CSAT project. Ratepayers should not be burdened with funding this project again. ORA recommends zero dollars for 2017 and 2018.[829]

Centralized Remedial Action Scheme (CRAS)

SCE requests the recovery of $15.31 million in this 2018 GRC for funds incurred in 2014-2016 to implement the Centralized Remedial Action Scheme (CRAS) project.[830] In SCE's 2015 GRC, the Commission partially adopted the CRAS project request, which included CRAS application development, implementation of central control telecommunication infrastructure, and deployment of two Remedial Action Schemes to validate full capabilities of CRAS on SCE's transmission grid.[831] SCE requested a total of $49.4 million in the 2015 GRC and the Commission partially approved the project funding and authorized expenditures through 2013. The Commission disallowed recovery of costs for 2014 and 2015.[832] In the 2015 SCE GRC Decision, the Commission allowed SCE to reapply for the denied capital expenditures in its next GRC, which is this TY 2018 SCE GRC, if SCE provided a detailed cost-benefit analysis in support of that request.[833]

SCE provided a detailed cost-benefit analysis in testimony and workpapers to support its CRAS request. ORA does not object to SCE's request to recover the 2014 and 2015 spending

[828] D.15-11-021, pp. 46-53.

[829] Ex. ORA-13, p. 34.

[830] Ex. SCE-04, Vol. 2, p. 115.

[831] Ex. SCE-04, Vol. 2, p. 115.

[832] Ex. SCE-04, Vol. 2, p. 116.

[833] Ex. SCE-04, Vol. 2, p. 116.

amounts of $4.82 million and $9.54 million, respectively.[834] SCE also requests $950,000 for 2016 and zero for 2017 and 2018. ORA recommends adopting the 2016 recorded amount of $1.635 million as the 2016 forecast.[835]

Distributed Energy Resources (DER) Related Projects

As part of its Capitalized Software forecast, SCE requests a total of $48.3 million, which consists of $30.7 million for 2017 and $17.6 million for 2018 to provide support for the following capital software projects: (1) Long Term Planning Tool, (2) Grid Interconnection Processing Tool (GIPT), (3) Grid Analytics Application and (4) Grid Connectivity Model.[836] The capital software projects are part of SCE's request for funding to support its Distributed Energy Resources (DER) investments.

DER is defined as distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.[837] DER is supported by a wide-range of Commission policies. At this time, the Commission is assessing these policies through several on-going proceedings.[838] These proceedings are: (1) Distributed Resource Plans: R.14-08-013; (2) Integrated Distributed Energy Resources: R14-10-003; (3) Energy Efficiency: R.13-10-005; (4) Energy Savings Assistance Program: A.14-11-002; (5) Demand Response: R.13-09-011; (6) Distributed Generation: R.12-11-005; (7) Energy Storage: R.10-12-007; (8) Alternative Fuel Vehicles: R.13-11-007; (9) Combined Heat and Power: R.15-07-028; (10) Renewable Portfolio Standards: R.14-07-002: (11) Time of Use: R.15-12-012; (12) Residential Rate Reform: R.12-06-013 and (13) Net Energy Metering: R.14-07-002.[839]

ORA recommends that the Commission reject SCE's request in this proceeding and authorize the tracking of the O&M expenses to support the four capital software projects identified above in the Grid Modernization memorandum account.[840] One reason for this is that

[834] Ex. SCE-04, Vol. 2, p. 115.

[835] Ex. ORA-13, pp. 34-35.

[836] Ex. SCE-04, Vol. 1, p. 42.

[837] *See* ORA-13, p. 34 citing CPUC Energy Division's 2016 DER Action Plan: Aligning Vision and Action, November 10, 2016, p. 1.

[838] *See,* Ex. ORA-13, footnote 87 citing CPUC Energy Division's 2016 DER Action Plan: Aligning Vision and Action, November 10, 2016, p. 1.

[839] Ex. ORA-13, p. 36.

[840] Ex. ORA-13, p. 12.

SCE states that its O&M expense forecasts were developed during the pre-planning phases of these projects.[841] The Commission should not rely on these estimates. They are unreliable, being both premature and inadequately supported. These projects are also related to, and dependent on, the outcomes of several open proceedings.[842] SCE's request in this GRC should not be allowed to prejudge findings and orders in other open proceedings, including the DRP proceeding.[843]

Moreover, if SCE implements these projects prematurely, the software may be obsolete or difficult to integrate with other systems at a later date. ORA, therefore, recommends the Commission authorize a memorandum account to record SCE's spending on DER-related projects. These costs could be tracked in the Grid Modernization memorandum account.[844]

Enterprise Content Management

According to SCE, "The Enterprise Content Management project is focused on improving SCE's capabilities to manage a diverse and complex set of business records."[845] The project, SCE says, will implement a set of eight solutions: (1) Digital Signatures, (2) Centralization of Critical Records, (3) Records Management Enhancements, (4) Management of Email Records, (5) Automate Records Management, (6) Preserve Digital Records with Extended Retention, (7) Enterprise Search and (8) Manage Structured Data Lifecycle.[846] SCE requests $3.400 million for 2017 and $5.200 million for 2018 for this project.[847]

SCE says the purpose of its proposed ECM is to have a centralized depository of business records that support the company's operations. SCE says the ECM project will minimize the risks of record-keeping non-compliance and provide advanced content management capabilities.[848] Essentially, SCE claims that this requested project will improve the accuracy of

[841] Ex. SCE-04, Vol. 1, p. 42.

[842] *See* ORA-13, p. 37, footnote 89 citing CPUC Energy Division's California's Distributed Energy Resources Action Plan: Aligning Vision and Action, November 10, 2016, p. 1, footnote 3.

[843] Ex. ORA-13, p. 13.

[844] Ex. ORA-13, p. 37.

[845] Ex. SCE-04, Vol. 2, p. 192.

[846] Ex. SCE-04, Vol. 2, pp. 192-193.

[847] Ex. SCE-04, Vol. 2, p. 192.

[848] Ex. SCE-04, Vol. 2, p. 192.

records and improve classification of information for the utility to meet its information protection needs.[849]

In SCE's 2015 GRC, the utility requested $11.4 million in ratepayer funding to implement a new system called Electronic Document Management Records Management (eDMRM).[850] The objectives of the TY 2018 Enterprise Content Management project are very similar to the objectives of SCE's 2015 GRC request for eDMRM. In the 2015 GRC application, SCE stated that the proposed eDMRM project would become the company's enterprise tool for managing unstructured contents such as MS Word, MS Excel, ".pdf," ".jpeg," ".tiff," ".awd," and ".avi files."

In this GRC, SCE states that "…eDMRM is no longer SCE's primary enterprise management system."[851] According to SCE, the utility transitioned off of eDMRM to Microsoft Office 365 in 2014, and now uses Microsoft SharePoint and OneDrive as the primary enterprise content management technology. In this GRC, SCE requests an additional $2.6 million to complete the eDMRM project.[852] SCE spent $2 million on this project in 2016. Going forward, "SCE plans to deploy a pilot of the digital signature capability for select business processes across the company."[853]

Many of the functions of the SCE proposed ECM project have already been implemented through the eDMRM project. For example, the requested project is called the "Enterprise Content Management" project. The eDMRM was an *enterprise content management system*.

The justifications for both the eDMRM project and the ECM project are very similar. For the eDMRM project, SCE claimed that it would make records accessible and enables quick and easy storing and retrieval of records.[854] SCE also stated that eDMRM would improve the

[849] Ex. SCE-04, Vol. 2, p. 192.

[850] Ex. ORA-13, p. 39, footnote 102 citing SCE's Testimony in its 2015 GRC, Ex. SCE-05, Vol. 02, Pt. 1, Information Technology—Capitalized Software, pp. 98-106.

[851] Ex. SCE-04, Vol. 2, p. 200.

[852] Ex. SCE-04, Vol. 2, p. 201.

[853] Ex. SCE-04, Vol. 2, p. 201.

[854] Ex. ORA-13, p. 39, footnote 99 citing SCE's Testimony in its 2015 GRC, Ex. SCE-05, Vol. 02, Pt. 1, Information Technology—Capitalized Software, p. 99.

Company's regulatory compliance and mitigate risks.[855] The benefits SCE claims that would be achieved by implementing the ECM are: (1) to minimize the risks of record-keeping non-compliance and (2) to enable accessible, accurate, and compliance with legal citations and regulations.[856] Also, SCE claimed eDMRM was necessary to manage the Company's emails.[857] In SCE's testimony regarding the need to implement ECM, the utility also claimed that this new system would be used to manage email records.

There also appear to be conflicting project justifications with the ECM and eDMRM. For the ECM, SCE states that this project will implement a digital signature technology for all eligible employees to digitally sign documents.[858] Yet, in the same testimony, SCE states that it plans to deploy a pilot of the digital signature capability for certain processes across the company.[859] SCE appears to be requesting funding for a digital signature pilot while also requesting funding for software that it has not tested to confirm that it could work for the company.[860]

SCE has not offered any assurance that it will not abandon the ECM project as it did with eDMRM. The Commission authorized a total of $18.2 million, and SCE spent $10.4 million on the eDMRM project for 2013-2015. After having received the $18.2 million in funds for eDMRM, SCE then replaced this system mid-way and began using Microsoft 365 as the new enterprise electronic documents and records management system.

In Rebuttal, SCE says "ORA's testimony appears to confuse the distinctions between the related (but separate) ECM and eDMRM projects."[861]

Actually, ORA has not confused these distinctions at all. ORA recommends no funding for 2017 and 2018 because SCE has not provided adequate support for its requests of $3.4 million for 2017 and $5.2 million for 2018. Ratepayers did not receive any benefits from

[855] Ex. ORA-13, p. 39, footnote 100 citing SCE's Testimony in its 2015 GRC, Ex. SCE-05, Vol. 02, Pt. 1, Information Technology—Capitalized Software, p. 102.

[856] Ex. SCE-04, Vol. 2, pp. 193-194.

[857] Ex. ORA-13, p. 39, footnote 102 citing SCE's Testimony in its 2015 GRC, Ex. SCE-05, Vol. 02, Pt. 1, Information Technology—Capitalized Software, p. 104.

[858] Ex. SCE-04, Vol. 2, p. 194.

[859] Ex. SCE-04, Vol. 2, p. 201.

[860] Ex. ORA-13, pp. 39-40.

[861] Ex. SCE-210, Vol. 1, p. 69.

completion of the original eDMRM project. SCE has not justified ratepayer funding for the new requests for 2017 and 2018. ORA recommends no funding for this project for 2017 and 2018.[862]

6.3 Information Technology – Customer Service Re-Platform

SCE asks for ratepayer funding to implement a new capitalized software project called Customer Service (CS) Re-Platform. The CS Re-Platform project will perform customer service related functions, such as generating customer bills and providing account management, overall customer care, credit and collections and account receivables. This project will replace SCE's legacy systems, which the utility claims are "outdated, obsolete, costly to maintain, and have increasing risk of failure."[863]

SCE requests a total of $208.7 million in capital expenditures from 2017 through 2020 to plan, analyze, design, build, test and deploy the new system.[864] For this rate case cycle, SCE's capital expenditures request is $129.3 million of the $208.7 million, with $58.3 million allocated to 2017 and $71 million allocated to 2018. ORA recommends $55.5 million for 2017 and $65.3 million for 2018. For 2017, ORA's recommendation is $2.8 million lower than SCE's request of $58.3 million. For 2018, ORA's recommendation is $5.7 million lower than SCE's request of $71.0 million. ORA's recommendations are based on applying a 15% contingency compared to SCE's request for 24% contingency for this project.[865]

Customer Service Re-Platform Capital Expenditures

ORA reviewed SCE's capital expenditures request of $208.7 million for the CS Re-Platform Project. ORA does not object to the implementation of the CS Re-Platform project. However, ORA recommends an adjustment of $15.4 million in capital expenditures for 2017 and 2018 based on using a lower contingency percentage/amount. ORA recommends applying a 15% contingency, instead of SCE's requested 24%, to the project cost.[866] This results in a

[862] Ex. ORA-13, p. 39.

[863] Ex. SCE-4, Vol. 3, p. 1.

[864] Ex. SCE-4, Vol. 3, p. 1.

[865] Ex. ORA-13, p. 41.

[866] Ex. ORA-13, p. 42, footnote 107: ORA applied the recommended 15% in contingency costs to the total project amount and allocated the adjusted costs to 2017 and 2018 using SCE's annual allocation method.

decrease of $15.4 million in total project costs, and therefore $2.7 million for 2017 and $5.7 million for 2018.

ORA's recommendation is based on a review of SCE's previous capital projects that SCE uses to support the CS Re-Platform capital expenditures forecast. ORA's testimony includes a figure taken from an SCE workpaper used to support the contingency percentage of 24%.[867] The workpaper presents a listing of previous capital expenditure projects and the authorized contingency percentages. At first, SCE's proposed 24% contingency appears reasonable. On examination, it is not.[868]

ORA asked SCE to identify the (1) Project Complexities and (2) Delivery Contingency for each project listed so that an analysis of the reasonableness of SCE's request for the CS Re-Platform could be performed. SCE's CS Re-Platform contingency requests are for "Project Complexities" and "Delivery Contingency."[869]

SCE did not provide the requested information, Instead, SCE responded that "…SCE did not develop a breakdown of contingency percentages [of the project identified used to support the CS Re-Platform project] by Project Complexities or Delivery Contingency."[870]

According to SCE, five of the six previous projects were completed under the forecast capital budget and without the use of contingency funding. The sixth project, SCE.com Strategic Upgrade, is not scheduled to be implemented until 2017, so whether SCE will need the contingency funding is unknown at this time.[871] These capital projects demonstrate that SCE has a pattern of overestimating the project risks in order to receive additional funding. SCE's overestimation of these projects resulted in at least $19 million of ratepayer funding for which ratepayers received nothing in return.[872]

ORA recognizes that the CS Re-Platform project is a major undertaking, and that some contingency might be necessary. However, SCE is using an experienced vendor to replace its current Customer Service system. In fact, according to SCE, "SCE's volume of customers limits

[867] Ex. ORA-13, p. 42.

[868] Ex. ORA-13, p. 43.

[869] Ex. ORA-13, p. 43.

[870] Ex. ORA-13-WP, p.3: SCE's response to data request ORA-SCE-032-DAO, Q.1.

[871] Ex. ORA-13-WP, p. 4: SCE's response to data request ORA-SCE-032-DAO, Q.2.

[872] Ex. ORA-13, p. 43.

the solution options to Oracle or SAP offerings as 'these two leading vendors provide comprehensive modern platforms, but at a substantial cost.' SCE examined 11 large utilities that have deployed a CIS solution since 2008. In over 60 percent of the cases, SAP was the chosen solution for CIS deployment."[873]

SCE also retained Accenture to evaluate the implantation schedule options for the project. SCE says that, "Accenture's recommendation [31 months] was based on its system integration experience leading SAP CR&B implementations of a comparable scope and complexity across the globe."[874]

ORA's recommendation of 15% in contingency is still within the range of the Commission's previously approved contingency for SCE. SCE's request for 24%, or $40.6 million, is excessive and likely will be unnecessary based on SCE's spending on capital projects in the 2015 GRC. ORA's recommendation for the total CS Re-Platform project is $193.3 million, which is $15.4 million lower than SCE's request of $208.7 million. ORA's 2017 and 2018 capital expenditures forecasts are $55.5 million and $65.3 million, respectively.[875]

Customer Service Re-Platform O&M Expense

SCE's requests a total of $55.5 million in one-time O&M expenses to implement the Customer Service Re-Platform project.[876] Of this total, SCE allocates $25.6 million, which is tracked in FERC Accounts 920/921, for the BID organization to support the implementation of the new CS Re-Platform system. The expenses consist of $22.4 million in expenses for SCE labor and $3.2 million in non-labor expenses for third-party vendor support and IT Software/Hardware.[877] Due to the uncertainty surrounding the forecasts and timing of these estimates, ORA recommends the one-time O&M expenses identified in FERC Accounts 920/921 be tracked in the same memorandum account as other identified CS Re-Platform related expenses.[878]

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[873] Ex. SCE-04, Vol. 3, p. 17.

[874] Ex. SCE-04, Vol. 3, p. 24.

[875] Ex. ORA-13, pp. 43-44.

[876] Ex. SCE-04, Vol. 3, p. 37.

[877] Ex. ORA-13, p. 44, citing Ex. SCE-04, Vol. 3 workpapers, p. 151.

[878] *See* Ex. ORA-12.

The remaining amount of $29.9 million is for the hiring and training of supplemental staff to support SCE Customer Service Representatives (CSRs), Billing Representatives and Credit and Payment Reps while they attend training on the new system.[879] The expenses for the training of supplemental staff are tracked in FERC Accounts 903.8, 903.5 and 903.2.[880]

ORA's analysis and recommendation regarding the CS Re-Platform one-time O&M expenses are addressed in Ex. ORA-12 and discussed in Section 6.3 above.

6.4 Information Technology – Additional Issues

ORA has no additional issues at this time.

7. GENERATION

7.1 Generation – Nuclear Generation (Palo Verde)

ORA does not oppose SCE's $76.7 million TY 2018 O&M expense forecast for Palo Verde.[881] Regarding refueling outages (RFO), ORA notes that the RFO forecasts in this GRC are more expensive than RFOs have been historically.[882] While this may be attributable to cycle specific costs, SCE and the Commission should be cognizant of RFO costs continuing to increase in future GRCs. ORA is not proposing an adjustment to SCE's RFO request. Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 Palo Verde capital requests.

7.2 Generation – Energy Procurement

ORA does not oppose SCE's $32.4 million TY 2018 O&M expense forecast for Energy Procurement.[883] Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 Energy Procurement capital forecasts.[884]

[879] Ex. ORA-13, p. 45, citing SCE-04, Vol. 3 workpapers, p. 152.

[880] Ex. ORA-13, p. 45, citing SCE-04, Vol. 3 workpapers, p. 152.

[881] EX. ORA-14, p. 5.

[882] EX. ORA-14, p. 7.

[883] Ex. ORA-14, p. 11.

[884] Ex. ORA-14, p. 12.

7.3 Generation – Hydro Generation

ORA does not oppose SCE's $26.8 million TY 2018 O&M expense forecast for hydro generation.[885] Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 hydro capital forecasts.[886]

7.4 Generation – Catalina

ORA does not oppose SCE's $4.4 million TY 2018 O&M expense forecast for Catalina generation.[887]

Regarding capital expenditures, ORA does not oppose SCE's Pebbly Beach Generating Station Automation Project, but does recommend that 2016 actual capital expenditures of $3.386 million be used in place of SCE's 2016 forecast of $3.4 million, a downward adjustment of $0.014 million.[888] SCE agreed.[889]

Regarding Other Capital Expenditures, Projects less than $3 Million, ORA recommends 2016 recorded capital of $0.007 million and $488,000 for 2017 and 2018 each, based on a five year average of SCE's capital expenditures from 2012-2016.[890] SCE agreed to use 2016 recorded capital, but on rebuttal revised its 2017-2018 combined capital estimate from $5.650 million down to $2.420 million, a reduction of $3.230 million.[891] Considering SCE's difficulties with forecasting 2016 Other Capital spending and its suddenly deflated 2017-2018 forecast, the Commission should adopt ORA's 2017-2018 Other Capital recommendation.

[885] Ex. ORA-14, p. 15.

[886] Ex. ORA-14, pp. 16-18.

[887] Ex. ORA-14, p. 33.

[888] Ex. ORA-14, p. 34.

[889] Ex. SCE-21, p. 3.

[890] Ex. ORA-14, p. 34. Regarding 2016, SCE spent $0.007 million of the $1.450 million that it requested for 2016.

[891] Ex. SCE-21, p. 9.

7.5 Generation – Other

7.5.1 Mountainview

ORA does not oppose SCE's $23.5 million TY 2018 O&M expense forecast for Mountainview. Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 Mountainview capital forecasts.[892]

7.5.2 Peakers

ORA does not oppose SCE's $7.5 million TY 2018 O&M expense forecast for the Peakers.[893] Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 Peakers capital forecasts.[894]

7.5.3 Mohave Closure

ORA does not oppose SCE's $583,000 TY 2018 O&M request to maintain the decommissioned Mohave site.[895]

7.5.4 Solar Photovoltaic

ORA does not oppose SCE's $3.8 million TY 2018 O&M request for its Solar Photovoltaic Program (SPVP).[896] Regarding capital expenditures, SCE has agreed to use 2016 recorded capital, and ORA does not oppose SCE's 2017-2018 SPVP capital forecasts.[897]

7.5.5 Fuel Cells

ORA does not oppose SCE's $379,000 TY 2018 O&M request for its Fuel Cell Demonstration Program.[898]

7.6 Generation – Additional Issues

ORA has no additional issues at this time.

8. HUMAN RESOURCES

8.1 Human Resources – O&M

SCE's Human Resources includes four departments: Talent Solutions; Business Partners; Total Rewards and Services; and Strategy and Workforce Insights.[899] Talent Solutions is the

[892] Ex. ORA-14, p. 25.

[893] Ex. ORA-14, p. 22.

[894] Ex. ORA-14, p. 26.

[895] Ex. ORA-14, p. 22. SCE's request reflects the full cost of maintaining Mohave; SCE's share is 56%.

[896] Ex. ORA-14, p. 29.

[897] Ex. ORA-14, p. 30.

[898] Ex. ORA-14, p. 31.

department charged with recruitment, testing and assessments, hiring, salary negotiations, diversity outreach and inclusion strategies, training, and succession planning for executive and management levels, among other things.[900] Business Partners works with the individual Operating Units (OU) to implement HR programs and activities within the OU, advises employees on HR-related issues for consistency across the Company, advises on organizational design, and negotiates and implements the Company's collective bargaining agreements.[901] Total Rewards and Services partners with OU management to evaluate workforce needs, develops and administers the Company's benefits and compensation, and ensures compliance with various state and Federal laws.[902] Strategy and Workforce Insights manages the Company's HR-related strategic initiatives, follows and advises on HR-related trends, issues, and opportunities, oversees the HR budget process, and manages the preparation of HR-related GRC and compliance filings.[903]

The table below summarizes SCE's request for HR Operations and Maintenance (O&M) expenses and compares ORA's recommendation and SCE's TY requests.[904]

2011-2015 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Account 920	$27,260	$28,196	$25,280	$26,973	$26,124	$24,357	$24,357
FERC Account 921	$11,635	$7,602	$11,981	$10,434	$8,047	$7,372	$7,372
FERC Account 923	$9,064	$8,245	$8,890	$12,248	$7,518	$6,954	$6,954
FERC Account 926	$7,227	$6,725	$7,423	$6,226	$5,913	$5,109	$5,109
Total	$55,186	$50,768	$53,574	$55,881	$47,602	$43,792	$43,792

Source: 2011-2015 and 2018 data from Ex. SCE-6, Vol. 1, pp. 20, 22 and 24.

[899] Ex. SCE-06, Vol. 1, p. 14.

[900] Ex. SCE-06, Vol. 1, pp. 15-16.

[901] Ex. SCE-06, Vol. 1, pp. 16-17.

[902] Ex. SCE-06, Vol. 1, pp. 17-18.

[903] Ex. SCE-06, Vol. 1, pp. 18-19.

[904] Ex. ORA-15, p. 4-5.

SCE books the costs of salaries to support the HR department to Federal Regulatory Energy Commission (FERC) Account 920. SCE's TY request for FERC Account 920 is $24.357 million. Office supplies and other non-labor expenses, such as, meals, travel, and cell phones, and background checks and drug screening for new employees, are booked to FERC Account 921. SCE's TY request for FERC Account 921 is $7.372 million.[905] Outside services are consultants for a variety of HR-related tasks, including training, audits, employee surveys, compensation analyses, and the GRC total compensation study and SCE books these costs to FERC Account 923. SCE's TY request for FERC Account 923 is $6.954 million.[906] SCE's HR labor and non-labor costs that are directly related to providing employee pensions and benefits are booked to FERC Account 926. SCE's TY request for FERC Account 926 is $5.109 million.[907] ORA analyzed the historical expenses and the TY forecasts for SCE's Human Resources O&M expenses and does not oppose them.[908]

Executive Officers O&M

SCE states cash compensation is an integral part of its executive total compensation package, which also includes long-term incentives, standard employee benefits, and special executive benefits. Costs included here include some executives shared with Edison International, whose compensation and expenses are allocated to SCE per D.88-01-063.[909]

The table below summarizes SCE's request for Executive Officers O&M expenses and compares ORA's recommendation and SCE's TY requests.[910]

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[905] Ex. SCE-06, Vol. 1, p. 19.

[906] Ex. SCE-06, Vol. 1, p. 22.

[907] Ex. SCE-06, Vol. 1, p. 23.

[908] Ex. ORA-15, p. 5-6.

[909] Ex. SCE-06, Vol. 1, p. 30.

[910] Ex. ORA-15, p. 6.

2011-2015 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Account 920	$16,519	$21,338	$16,753	$17,044	$14,456	$17,222	$17,222
FERC Account 921	$2,959	$2,863	$2,670	$2,705	$2,389	$2,389	$2,389
FERC Account 923	$1,499	$1,979	$1,553	$1,253	$1,452	$1,547	$1,547
Total	$20,977	$26,180	$20,976	$21,002	$18,297	$21,158	$21,158

Source: 2011-2015 and 2018 data from Ex. SCE-6, Vol. 1, pp. 35 and 38.

SCE books salaries and incentive bonus costs for executive officers, and salaries for their administrative assistants, to FERC Account 920. For forecasting purposes for this GRC, the costs related to incentive bonuses for non-officer executives were transferred to the STIP activity in the organization corresponding to each executive's activity group.[911] SCE's TY request for FERC Account 920 is $17.222 million. SCE booked office supplies and other non-labor expenses, such as meals, travel, and cell phones to FERC Account 921. SCE's TY request for FERC Account 921 is $2.389 million.[912] Outside services are consultants for a variety of services related to executive compensation and benefits, including the actuarial valuation of executive retirement plans, calculation of executive benefits, and the design of executive benefit and incentive programs; and SCE booked these costs to FERC Account 923. SCE's TY request for FERC Account 923 is $1.547 million.[913] ORA analyzed the historical expenses and the TY forecasts for SCE's Executive Officers O&M expenses and does not oppose them.[914]

8.2 Benefits and Other Compensation

SCE's employee Pension and Benefit (P&B) programs include: pension and postretirement benefits, including contributions to trust funds; 401(k) savings plan; health plans including medical, dental, and vision coverage; group life insurance; supplemental executive benefits; and Miscellaneous Benefits, which include an employee electric service discount,

[911] Ex. SCE-06, Vol. 1 workpapers, p. 84.

[912] Ex. SCE-06, Vol. 1, p. 35.

[913] Ex. SCE-06, Vol. 1, p. 38.

[914] Ex. ORA-15, p. 7.

commuter benefits, education reimbursement, and some costs related to the ACE program.[915] SCE forecasts $370.789 million for Pension and Benefits Programs, while ORA forecasts $353.641 million.[916]

SCE eliminates the Cash Balance retirement plan for new employees hired on or after December 31, 2017, and instead provides a non-elective contribution to the 401(k) accounts of those new employees.[917] The non-elective 401(k) contribution will be between 4% and 6% of an employee's base pay, depending on age, service, and union status.[918] This change is expected to lower the company's long-term retirement plan obligations.[919]

SCE provides all eligible employees with comprehensive medical coverage including preventive care, prescription coverage, mental health and substance abuse treatment.[920] Employees choose from a variety of health plans, which may vary depending on their location, and which offer a variety of care choices as well as cost-sharing options such as fixed co-payments or co-insurance percentages for health services, and different levels of payroll contributions and/or annual deductibles. Employees who choose the lowest-cost option pay 15% of the premium for themselves and 20% for their dependents; employees who choose other plans pay that amount, plus 100% of the difference between the plan they choose and the lowest-cost plan.[921] SCE also offers three dental plans, all of which provide free preventive care but have different cost-sharing levels for additional services; employees pay 15% of their premium and 20% for dependent coverage.[922]

SCE provides group life insurance coverage for all employees for one times their base pay, up to $50,000; additional coverage for the employee and for dependents may be purchased at the employee's cost. SCE also provides eligible employees with $50,000 in Accidental Death & Dismemberment insurance coverage; additional coverage for the employee and for dependents

[915] Ex. SCE-06, Vol. 2, p. 41.

[916] Ex. ORA-15, p. 15.

[917] Ex. SCE-06, Vol. 2, p. 46.

[918] Ex. SCE-06, Vol. 2, p. 61.

[919] Ex. SCE-06, Vol. 2, p. 46.

[920] Ex. SCE-06, Vol. 2, p. 65.

[921] Ex. SCE-06, Vol. 2, pp. 65-67.

[922] Ex. SCE-06, Vol. 2, pp. 78-79.

may be purchased at the employee's cost. Business Travel Accident Insurance is provided at no cost with coverage equal to two times the employee's base pay, with maximum levels that vary by employee level.[923]

SCE calculates most of its benefit program expenses by multiplying the individual program cost by its projected headcount.[924] Because ORA's labor forecast is lower than SCE's projection, ORA's TY recommendations for these programs are lower than SCE's.[925] ORA has reviewed the programs, historical expenses, and projected TY program cost forecasts for SCE's P&B programs and does not oppose the TY program costs for the following programs:

- Pension ($97.474 million request, subject to two-way balancing account treatment.)
- PBOP ($36.823 million request, subject to two-way balancing account treatment.)
- 401(k) Savings Plan ($79.190 million request.)
- Dental ($15.035 million request, subject to the Medical Programs Balancing Account.)
- Vision ($3.443 million request, subject to the Medical Programs Balancing Account.)
- Group Life ($1.426 million request.)
- Miscellaneous Benefits with the exception of Recognition Programs as discussed in Section VI above.

The table below summarizes SCE's request for pension and benefits programs and compares ORA's recommendation and SCE's TY requests.[926]

[923] Ex. SCE-06, Vol. 2, pp. 93-95.

[924] Ex. SCE-06, Vol. 2, workpapers pp. 24-25 show the calculations of the program costs for the various benefit programs.

[925] Ex. ORA-2.

[926] Ex. ORA-15, p. 18.

2011-2015 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
Pension Costs	$94,367	$146,080	$156,245	$122,336	$87,739	$97,474	$97,474
401(k) Savings	$83,761	$83,709	$75,008	$74,000	$69,808	$79,190	$75,965
Medical	$124,097	$129,234	$127,359	$100,166	$90,153	$110,719	$101,478
Dental	$15,111	$15,586	$14,527	$11,230	$12,909	$15,035	$14,452
Vision	$3,667	$3,575	$3,289	$2,499	$2,873	$3,443	$3,309
PBOP Costs	$34,520	$50,944	$30,835	$17,449	$22,477	$36,823	$36,823
Group Life	$1,573	$1,515	$1,556	$1,198	$1,329	$1,426	$1,370
Misc. Benefits	$7,138	$5,235	$5,170	$5,318	$4,894	$5,592	$3,976
Exec. Benefits	$18,126	$20,925	$17,144	$14,117	$19,658	$21,087	$10,135
Total	$382,360	$456,803	$431,133	$348,313	$311,840	$370,789	$344,982

Source: 2011-2015 and 2018 data from Ex. SCE-6, Vol. 2, p. 43.

Medical Programs Expense

SCE calculated its medical programs expense by multiplying the projected number of employees by the projected program cost.[927] To calculate the projected program cost, SCE projects a medical escalation rate of 7.0% for 2017 and 2018.[928] ORA determined the reasonableness of the proposed medical escalation rate by consulting several well-regarded sources of healthcare cost statistics. SCE quotes a report from Milliman, Inc. as one of its sources for its proposed 7% increase in healthcare costs. The report quoted was prepared in April 2013.[929] A more recent report, produced by Milliman, Inc. in May 2016, projects an average of 4.7% increase in healthcare costs, which is the lowest annual increase since Milliman first measured medical costs in 2001.[930] For California specifically, the California Employer Health Benefits Survey found an average increase of 5.6% in family coverage healthcare

[927] Ex. SCE-06, Vol. 2, p. 68.

[928] Ex. SCE-06, Vol. 2, p. 76.

[929] "2016 Milliman Medical Index," p. 1. Retrieved from http://us.milliman.com/uploadedFiles/insight/Periodicals/mmi/2016-milliman-medical-index.pdf

[930] Ex. SCE-06, Vol. 2, p. 72, fn. 88.

premiums for 2016[931] and the Kaiser Family Foundation's Medical Expenditure Panel Survey found that California employer-based health insurance premiums averaged a 3.45% increase in total family healthcare premiums from 2014 to 2015.[932]

Because of the Medical Programs Balancing Account, ratepayers fund only SCE's actual costs to provide this benefit to its employees, but any over-collection is not refunded to ratepayers until the next year.[933] ORA recommends using Milliman, California Employer Health Benefits Survey, and Kaiser Family Foundation's medical escalation rates to forecast this expense. ORA's proposed medical escalation rate of 4.58% is determined by an average of the three insurance premium rate increases discussed above, two of which are specific to California employers. ORA applied this escalation rate to SCE's projected program cost to arrive at ORA's forecast of $101.478 million, which is a difference of $9.241 million.[934]

The table below shows the calculation of ORA's recommended medical escalation rate.

ORA's Medical Escalation Rate Calculation

Projected/Actual Increases	
Milliman, Inc. Report	4.70%
CA Employer Health Survey	5.60%
Kaiser Family Foundation	3.45%
Average Increase	4.58%

8.2.2 Supplemental Executive Benefits

SCE offers a non-qualified Executive Retirement Plan that provides benefits to certain highly-paid management employees who are subject to federal compensation and contribution limits in the retirement plans which are offered to all other SCE employees.[935] This plan

[931] "California Employer Health Benefits: Prices Up, Coverage Down," p. 2. http://www.chcf.org/~/media/MEDIA%20LIBRARY%20Files/PDF/PDF%20E/PDF%20EmployerHealthBenefits2017.pdf.

[932] http://kff.org/other/state-indicator/family-coverage/?dataView=0&activeTab=graph&currentTimeframe=0&startTimeframe=1&selectedDistributions=total&selectedRows=%7B%22nested%22:%7B%22california%22:%7B%7D%7D%7D&sortModel=%7B%22colId%22:%22Location%22,%22sort%22:%22asc%22%7D $17,044 to $18,045 = 3.45%.

[933] SCE Medical Programs Balancing Account tariff, Cal. PUC Sheet No. 44979-E (Sheet 3): https://www.sce.com/NR/sc3/tm2/pdf/CE314.pdf.

[934] Ex. ORA-15, p. 19.

[935] Ex. SCE-06, Vol. 2, p. 101.

provides benefits to covered employees on the same basis as the retirement plan SCE offers to all other SCE employees, but without any income and contribution limits. There is no pre-funded trust for the Executive Retirement Plan; the recorded expense includes benefit payments.[936]

SCE is making two changes to its Executive Retirement Plan. First, beginning in 2018, the formula for benefit calculations will be changed from 1.75% of final average pay for up to 30 years of service and 1% of final average pay for over 30 years of service; the new benefit calculations will use 1% and 0.5%, respectively. Also beginning in 2018, newly hired executives and those newly promoted into executive positions will no longer participate in the Executive Retirement Plan; these employees will instead receive additional non-elective contributions into their 401(k) accounts, as described on pages 15-16 above and as allowed by law, and into a new Executive Retirement Account (ERA). Deposits into each executive's ERA will be comprised of 12% of their annual EIC payout, 12% of their base pay that exceeds IRS limitations for deposit into their 401(k) account and interest credits. The combination of the ERA benefit and the revised Executive Retirement Plan cannot exceed what the executive would have received under the pre-2018 plan.[937]

In prior GRCs, ORA has taken the position that ratepayers should not bear the full cost of these supplemental benefits which are in excess of federal limits and which serve to further enhance benefits to already highly-compensated employees. SCE's executive benefits are 96.4% above market, according to the TCS, which clearly indicates that SCE is already providing very generous benefits to its executives.[938] The Commission has also not required full ratepayer funding for executive benefits for many years, adopting 50% of the executive benefits for ratepayer funding in the last cycle of GRCs for the major utilities and the past three SCE GRCs.[939] In SCE's 2012 GRC, the Commission specifically noted that 50% was a reasonable amount for ratepayers to bear.[940] In SCE's most recent TY 2015 GRC, D.15-11-015 stated:

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[936] Ex. ORA-15, p. 20.

[937] Ex. SCE-06, Vol. 2, p. 102.

[938] Ex. SCE-06, Vol. 3, p. 4.

[939] D.14-08-032, p. 535, D.15-11-021, p. 261, D.15-11-015, p. 275, D.12-11-051, pp. 476-477, and D.09-03-025, p. 271.

[940] D.12-11-051, p. 450.

> For Executive Benefits, we follow the precedent of the 2009 and 2012 GRCs, and allow 50% rate recovery of SCE's forecast. These Executive Benefits are, in part, based on bonuses received by the executives. As discussed above, these bonuses may not be appropriate for rate recovery. Accordingly, benefits based on those bonuses are also not appropriate.[941]

SCE forecasts $21.09 million for these supplemental executive benefits.[942] Considering Commission history and precedent, ORA recommends ratepayer funding of only 50% for a total TY program expense of $10.135 million.[943]

8.3 Human Resources-Total Compensation Study

ORA has not comments on this issue at this time.

8.4 Human Resources- Additional Issues

Short-term Incentive Programs

SCE's short-term incentive programs include the Short-Term Incentive Plan (STIP) and the Executive Incentive Compensation Plan (EIC) that SCE states are designed to attract, retain and reward employees by providing bonus opportunities linked to performance.[944] SCE forecasts $133.848 million for STIP, an incentive pay program for most exempt and all non-exempt employees, and for EIC, which covers executives who are not officers (less than 1% of SCE's employee population).[945] The corresponding ORA recommendation is $70.672 million.

The table below summarizes SCE's request for short term incentive plans and compares ORA's recommendation and SCE's TY requests.[946]

[941] D.15-11-015, p. 275.

[942] Ex. SCE-06, Vol. 2, p. 102.

[943] Ex. ORA-15, p. 2.

[944] Ex. SCE-06, Vol. 2, p. 1.

[945] Ex. SCE-06, Vol. 2, p. 22.

[946] Ex. ORA-15, p. 8.

2011-2015 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Account 500	$3,931	$10,584	$8,802	$9,287	$6,982	$7,516	$4,134
FERC Account 588	$51,641	$62,700	$62,022	$71,130	$56,505	$64,905	$34,787
FERC Account 905	$21,316	$23,238	$19,069	$20,639	$15,305	$17,039	$8,971
FERC Account 920-921	$57,255	$69,970	$62,588	$66,476	44,221	$44,389	$22,780
Total	$134,143	$166,492	$152,481	$167,532	$123,013	$133,848	$70,672

Source: 2011-2015 and 2018 data from Ex. SCE-6, Vol. 2, p. 22.

SCE's short-term incentives program was previously known as the Results Sharing Program. Through 2014, STIP funding was based on SCE's four goals: Company goals; the Company's O&M budget; OU goals; and each OU's O&M budget. In 2015, SCE changed these goals to: O&M budget; OU goals; and safety goals, with safety being just 10% of the total potential payout.[947] In 2016, SCE again revised the goals with safety goals remaining at 10%.[948] The remaining goals for 2016 STIP payouts are: customer relationships and operational excellence (20%); "Grid of the future," (20%); "High Performance Organization," which includes items such as diversifying the leadership pipeline, enhancing the decision-making process, and encouraging employee engagement (10%); and Company financial performance goals (40%).[949]

[947] Ex. SCE-06, Vol. 2, p. 23.

[948] Ex. SCE-06, Vol. 2, p. 25.

[949] Ex. SCE-06, Vol. 2, pp. 24-25.

SCE Short-Term Incentive Plan
SCE and ORA Proposed Ratepayer Funding Levels

	Proposed Percentages		Proposed Dollar Amounts	
	SCE	**ORA**	**SCE**	**ORA**[950]
Safety	10.00%	10.00%	$13,385	$13,385
Cust. Relationships/ Oper. Excellence	20.00%	20.00%	$26,770	$26,770
"Grid of the Future"	20.00%	20.00%	$26,770	$26,770
High Performance Organization	10.00%	5.00%	$13,385	$6,692
Financial Goals	40.00%	0.00%	$53,539	$0
Total	100.00%	55.00%	$133,848	$73,616

ORA recommends ratepayers fund the portions of STIP directly associated with safety, customer relationships and operational excellence, and "Grid of the future" because these goals benefit ratepayers.[951]

ORA recommends that the portion of STIP related to "High Performance Organization," be shared equally between shareholders and ratepayers. SCE goals of diversifying the leadership pipeline, enhancing the decision-making process, and encouraging employee engagement do not clearly provide ratepayer benefits and do not appear to be transparent or readily quantifiable. Thus, these category goals can equally benefit the company and shareholders.

ORA recommends no ratepayer funding of STIP related to financial goals. SCE's STIP program includes 40% related to financial goals.[952] Incentive criteria tied to financial goals are clearly shareholder oriented. Ratepayers do not benefit directly from this in contrast to benefits to shareholders with dividends and higher stock prices.

[950] Due to ORA's labor dollar adjustments, ORA's final dollar amounts for STIP are slightly different than those calculated here.

[951] Ex. ORA-15, p. 10.

[952] Ex. SCE-06, Vol. 2, p. 25.

Thus, there is no justification to support ratepayer funding of this aspect of the incentive matrix. ORA's recommendation is similar to its recommendation in the PG&E and Sempra GRCs, which were both settled.[953] This is also consistent with SCE's last GRC decision, in which the Commission stated, "In recent GRCs, we have adopted reductions to short term incentives to account for payouts that are driven by shareholder benefits rather than ratepayer benefits."[954] ORA strongly recommends ratepayers not be required to fund the STIP request related to financial goals.[955]

Based on the policies and adjustments discussed above, ORA recommends a ratepayer funded TY STIP expense of $70.672 million, compared to SCE's request of $133.8 million.

Long-Term Incentive Programs

SCE's long-term incentive program (LTIP) apply to "executives," but to all employees at the Director level as well.[956] SCE forecasts $13.726 million for LTIP expenses, while ORA recommends zero.[957]

The table below summarizes SCE's request for long-term incentive plans and compares ORA's recommendation and SCE's TY requests.

2011-2015 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Account 920-921	$22,468	$20,160	$17,589	$20,329	$16,042	$13,726	$0
Total	$22,468	$20,160	$17,589	$20,329	$16,042	$13,726	$0

Source: 2011-2015 and 2018 data from Ex. SCE-6, Vol. 2, p. 33.

SCE states that the LTI program benefits ratepayers, in part, because of better executive-level retention.[958] In response to a data request, SCE provided information on executive-level

[953] For PG&E, a final decision has not been voted on by the Commission; the application is A.15-09-001. For Sempra, see D.16-06-054.

[954] D.15-11-021, p. 264.

[955] Ex. ORA-15, p. 10

[956] SCE response to data request ORA-SCE-012-STA, Q.1.

[957] Ex. ORA-15, p. 11.

headcounts from 2009 through 2016, by position, which indicates this is not accurate. After condensing positions that had slightly different titles but appear to be the same job (such as "VP & Assoc General Counsel" and "VP & Associate General Counsel," for example) and positions that were apparently promoted (four years of "VP and Chief Information Officer," and one year of "SVP and Chief Information Officer," for example) there are only a few dozen positions which had an incumbent for more than three of those eight years. In fact, less than half of the executive officer positions and less than a third of the non-officer executive positions had an incumbent for four or more of those eight years.[959] Although SCE claims to not track executive vacancies,[960] the executive headcounts from year to year show that SCE has had vacancies in many positions during the past eight years. This disputes SCE's claim that LTI results in better executive retention.[961]

SCE claims that LTI benefits ratepayers through "lower costs,"[962] but this is also not supported by the evidence available. In SCE's 2012 GRC, the Company had 31 executives who were paid an average of about $470,000, and those executives received benefits that were 70.5% above market.[963] In SCE's 2015 GRC, the Company had 41 executives who were paid an average of about $515,000, and those executives received benefits that were 114.3% above market.[964] In this GRC, SCE has 43 executives who are paid an average of about $610,000, and these executives receive benefits at 96.4% above market.[965] In just six years, the average base pay for an executive at SCE has increased 30%, and with a 40% increase in executive population at SCE, the total payroll for executives has nearly doubled. This is in addition to executive benefits which are nearly double in value to those of SCE's market comparators. SCE is not

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[958] Ex. SCE-06, Vol. 2, p. 34.

[959] SCE response to data request ORA-SCE-171-STA, Q.1, attachment Q.01a, lists a total of 339 positions, which was condensed to 252 non-officer executive positions and 50 executive officer positions. Of those, only 90 positions were filled for four or more (non-consecutive) years, 70 non-officer executives (28%) and 25 executive officers (45%).

[960] SCE response to data request ORA-SCE-171-STA, Q.1.

[961] Ex. ORA-15, p. 12.

[962] Ex. SCE-06, Vol. 2, p. 34.

[963] See testimony from 2012 GRC, Ex. SCE-06, Vol. 2, Appendix B, p. B-5.

[964] See testimony from 2015 GRC, Ex. SCE-06, Vol. 2, Part 2, p. 4.

[965] Ex. SCE-06, Vol. 3, p. 4.

lowering costs by trimming executive salaries or benefits. While it is true that some employee benefits are calculated on base pay, the supplemental executive benefits include incentive pay in their calculations. Thus, this contradicts SCE's claim that LTI results in lower costs.[966]

The Commission has consistently declined to provide rate recovery for LTI.[967] (PG&E does not request ratepayer funding for LTI.)[968] The Commission, in a recent Sempra GRC decision, stated that because stock-based compensation is tied to financial performance over a period of time, "that clearly demonstrates that a premium is being placed on the companies' financial performance."[969] The most recent Sempra GRC decision, D.16-06-054, was a settlement which included no ratepayer funding for LTI for either company.[970] In SCE's most recent GRC decision, the Commission stated, "SCE has not demonstrated that LTI furthers the provision of safe and reliable service at just and reasonable rates."[971] D.15-11-021 additionally stated:

> In recent decisions, we have held that LTI is not recoverable from ratepayers because LTI does not align executives' interests with ratepayer interests. SCE's arguments to the contrary are vague, limited, and unpersuasive… We continue our consistent practice and reject rate recovery of SCE's LTI program.[972]

SCE has not demonstrated in this filing that anything has changed since then. ORA's recommendation is that ratepayers continue to not fund SCE's LTI request.[973]

8.4.2 Recognition Programs

SCE's Recognition Programs involve both cash and non-cash awards. Cash awards are given in the form of spot bonuses and SCE states that they are an important tool for recognizing

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[966] Id.

[967] D.12-11-051, pp. 451-452; D.13-05-010, pp. 882-884; and D.15-11-021, p. 266.

[968] A final decision has not been voted on by the Commission in A.15-09-001; ORA's discussion of LTI is included in PG&E GRC Ex. ORA-16, p. 9. Also see D.11-05-018, p. 97, which relieves PG&E of the obligation to include LTI in future TCS, as they are not funded by ratepayers.

[969] D.13-05-010, p. 884.

[970] D.16-06-054, SoCalGas Settlement Motion, SoCalGas Settlement Comparison Exhibit, p. 10, and SDG&E Settlement Motion, SDG&E Settlement Comparison Exhibit, p. 12.

[971] D.15-11-021, p. 266.

[972] *Ibid*.

[973] Ex. ORA-15, p. 13.

and rewarding employees for exceptional performance and outstanding achievement.[974] Non-cash awards are given under the "Awards to Celebrate Excellence" (ACE) recognition program. ACE awards are given as program points to reward employees who contribute to a safe working environment or public safety;[975] this is a change from the prior program that rewarded customer service, teamwork and initiative. Other program changes made in 2016 include an expansion of the program so that ACE award nominations are now open to all non-executive employees in all OUs, and awards can be made by any manager (not just an employee's manager) if the manager witnesses something related to changing the company's safety culture.[976]

SCE fails to provide the transparency needed to justify ratepayer funding of these programs. SCE states that each OU has "limited budget dollars" to spend on these programs,[977] but provides no historical expense levels beyond the base year to support this claim, no breakdowns of the costs of the programs by Operating Unit or job category to aid in any analysis, and nothing to justify this expense other than, "everyone else does it."[978]

SCE forecasts $1.456 million for Recognition Program expenses, which is based on 2015 recorded costs of $1.337 million.[979] Compared to SCE's 2015 total company labor of $829.1 million, the cost for these programs in 2015 was approximately 0.16% of SCE's labor, which matches SCE's claim of a 0.2% budget. However, SCE recorded these costs before the program expansion, so they should be expected to be lower than SCE's budget projections into the future. Since SCE did not provide historical data for comparison, ORA cannot determine whether the costs recorded in 2015 are accurate or an anomaly. ORA recommends no ratepayer funding for SCE's Recognition Programs. Because most of the costs for Recognition Programs are spread

[974] Ex. SCE-06, Vol. 2, p. 39.

[975] Ex. SCE-06, Vol. 2, p. 40.

[976] Phone call on March 14, 2017 with Mark Bennett, Michelle Ricard and Rahab Mahsud.

[977] Ex. SCE-06, Vol. 2, p. 41 claims that this amount is 0.2% of the labor budget.

[978] Ex. SCE-06, Vol. 2 workpapers, Chapter III-VIII, p. 114 shows that 80% of respondents to a WorldAtWork survey said their company provides a budget for recognition programs, and 97% of those companies provide payroll dollars for those programs.

[979] Ex. SCE-06, Vol. 2, p. 98, states that individual OUs also record costs associated with the ACE program in their non-labor costs.

throughout the company's OU non-labor costs, ORA removed the forecast of $1.456 million from Miscellaneous Benefits.[980]

9. OPERATIONAL SERVICES

9.1 Business Resiliency

SCE's Business Resiliency capital request is for electric infrastructure seismic assessment and mitigation.[981] Electric infrastructure in scope for assessment and mitigation for 2016-2018 includes transmission towers, lines, and corridors, transmission substations, and distribution substations and distribution system related assets, such as older poles with overhead mounted equipment racks and some on-grade mounted unrestrained transformers.[982] SCE requests $6.337 million for capital in 2016, $31.261 million for capital in 2017, and $33.921 million for capital in 2018.[983]

ORA recommends using recorded 2016 capital of $4.019 million, and does not oppose SCE's requests for $31.261 million in 2017 and $33.921 million in 2018.

However, for Operational Services expenses for TY 2018, under Business Resiliency, FERC Accounts 920/921, ORA recommends $6.357 million, which is $74,000 less than SCE's request of $6.431 million.[984]

The Business Resiliency Department provides company-wide governance and program management for SCE's business continuity and disaster recovery programs, assessment and mitigation programs and emergency planning and response.[985] Business Resiliency's Plans and Programs, Emergency Operations and Governance and Analytics groups establish and manage those programs.[986]

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[980] Ex. ORA-15, pp. 14-15.

[981] Ex. SCE-7, Vol. 1, p. 27.

[982] Ex. SCE-7, Vol. 1, p. 27.

[983] Ex. ORA-16, p. 29.

[984] Id. at p. 1.

[985] Ex. SCE-7, Vol. 1, p. 1.

[986] Ex. SCE-7, Vol. 1, p. 2.

For Test Year 2018, Business Resiliency forecasts $7.964 million in Operational Services expenses, which is a $1.734 million increase over 2015 recorded $6.230 million.[987] The chart below recorded figures for Business Resiliency and SCE's 2018 forecast.

Business Resiliency
2011-2016 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
Business Resiliency 920/921	$2,587	$1,934	$2,559	$5,328	$6,230	$6,431	$6,357
Seismic Mitigation 935	$0	$0	$0	$0	$0	$1,533	$1,533
Total	$2,587	$1,934	$2,559	$5,328	$6,230	7,964	$7,890

Again, ORA recommends $7.890 million which is $74,000 less than SCE's requested $7.964 million.

9.2 Corporate Environmental Services

In Corporate Environmental Services capital expenditures, ORA recommends the use of recorded 2016 capital of $532,000, and does not oppose SCE's requests for $660,000 in 2017 and $672,000 in 2018.[988]

9.3 Corporate Real Estate

Corporate Real Estate (CRE) plans, manages, and maintains SCE's electric and non-electric facility portfolio, comprised of approximately 1,300 buildings covering more than 7.3 million square feet.[989] CRE includes: Service Center Modernization Program, Operational Support Program, Blanket Capital Program and IT Infrastructure and Equipment.[990] SCE's

[987] Ex. SCE-7, Vol. 1, p. 2.

[988] Ex. ORA-16, p. 1.

[989] Ex. SCE-7, Vol. 3, p. 36.

[990] Ex. SCE-7, Vol. 3, p. 36.

capital forecast for Corporate Real Estate is $136.001 million in 2016, $167.820 million in 2017 and $213.346 million in 2018.[991]

ORA recommends adopting the 2016 recorded capital of $96.576 million, and forecasts $119.149 million in 2017 and $147.768 million for capital in 2018. SCE underspent its 2016 forecast by 29%. ORA forecasts that such underspending will carry over in 2017 and 2018, especially given that the highest level of capital expenditures during 2011-2016 period was $125.505 million in 2014.[992]

Corporate Real Estate OS
ORA Recommended and SCE Proposed
2016-2018 Capital Expenditure Forecasts
(in Thousands of Nominal Dollars)

Description	ORA Recommended			SCE Proposed[993]		
	2016	2017	2018	2016	2017	2018
Service Center Modernization	$7,068	$40,315	$28,419	$25,018	$56,782	$40,026
Operational Support	$51,411	$31,253	$63,975	$64,733	$44,022	$95,317
Blanket Capital	$28,121	$41,767	$48,918	$37,830	$58,828	$68,899
IT Infrastructure and Equipment[994]	$9,976	$5,814	$6,464	$8,420	$8,189	$9,105
Total	$96,576	$119,149	$147,768	$136,001	$167,820	$213,348

9.4 Corporate Health & Safety

SCE's Corporate Health and Safety (CHS) department is responsible for the health and safety oversight and services at the corporate level.[995] This includes developing and managing

[991] Ex. SCE-7, Vol. 3, p. 52, 80,108,112,124,131 and 132 and ORA's RO numbers provided by SCE to ORA 9/1/16.

[992] Id. at p. 30.

[993] Ex. SCE-7, Vol. 3, pp. 52, 80,108,112,124, 131 and 132 and ORA's RO numbers provided by SCE to ORA 9/1/16.

[994] Because SCE's response to data request ORA-SCE-108-TXB, Q.2 2016 recorded CapEx separated IT capital expenses in CRE from Service Center Modernization Program, Operational Support Program and Blanket Capital Program, ORA elected to use the same methodology in its forecast. Thus, ORA's numbers within this testimony are slightly different from the numbers which appear in Ex. SCE-7, Vol. 3 where SCE incorporated IT information rather than separating it out as it did in ORA-SCE-108-TXB, Q.2 2016 recorded CapEx.

[995] Ex. SCE-7, Vol. 4, p. 1.

programs that meet regulatory requirements outlined in the Occupational Safety and Health Act (OSHA), leading all safety incident investigations, tracking and analyzing SCE's safety data and records, managing and implementing the Enterprise Safety Program, as well as managing all other office safety programs and standards.[996]

CHS forecasts 2018 O&M expenses of $5.688 million, which is a $635,000 increase from 2015 recorded/adjusted spend of $5.053 million for the same accounts.[997] ORA forecasts $4.988 million for SCE's Corporate Environmental Services, which is $700,000 less than SCE's request for $5.688 million in TY 2018.[998]

Corporate Health and Safety[999]
2011-2016 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Acct 925	$6,586	$5,662	$5,022	$6,374	$5,053	$5,688	$4,988
Total	$6,586	$5,662	$5,022	$6,374	$5,053	$5,688	$4,988

ORA recommends $4.988 million, which is $700,000 less than SCE's requested $5.688 million for various reasons. First, ORA does not oppose SCE's Test Year labor CHS forecast of $3.364 million.[1000]

Next SCE's Test Year non-labor CHS forecast is $2.324 million.[1001] SCE developed its forecast by using a three year average of 2013-2015 ($1.624 million) as their base estimate with an additional $700,000 for research costs.[1002] SCE chose a three year average for non-labor costs in FERC Account 925 because fluctuations from year to year align with the Safety Culture Assessment that is conducted every three years.[1003] The averaging technique spreads the costs

[996] Ex. SCE-7, Vol. 4, p. 1.
[997] Ex. SCE-7, Vol. 4, p. 11.
[998] Ex. ORA-16, p. 18.
[999] Ex. SCE-7, Vol. 4, p. 11.
[1000] Ex. ORA-16, p. 19.
[1001] Ex. SCE-7, Vol. 4, p. 12.
[1002] Ex. SCE-7, Vol. 4, p. 12.
[1003] Ex. SCE-7, Vol. 4, p. 12.

associated with the assessment over the three year rate case cycle and will include the $680,000 forecast to cover the cost of the assessment.[1004] ORA does not oppose SCE's forecasting methodology.[1005]

However, ORA does oppose the additional $700,000 requested for SCE's participation in the Electric Power Research Institute's (EPRI) Program 60 (Electric and Magnetic Fields and Radio-Frequency Health Assessment and Safety).[1006] The CPUC declined to provide funding for Program 60 via the Electric Program Investment Charge (EPIC) in D. 15-04-020 since Program 60 was not a Technology Demonstration and Deployment (TD&D) activity.[1007] The Commission agreed with ORA that "SCE must only fund the demonstration and deployment of technologies and strategies in this area, not background research." ORA maintains this position and requests the Commission once again not allow funding for Program 60 as it had in the previous GRC.[1008]

9.5 Corporate Security

In Corporate Security capital expenditures, ORA recommends the use of recorded 2016 capital of $19.261 million, and does not oppose SCE's requests for $39.666 million in 2017 and $22.380 million in 2018.[1009]

9.6 Supply Management

In Supply Management capital expenditures, ORA recommends the use of recorded 2016 capital of $198,000, and does not oppose SCE's requests for $563,000 in 2017 and $365,000 in 2018.[1010]

9.7 Supplier Diversity

SCE's Supplier Management and Supplier Diversity and Development Department (SDD) manages the Utility's efforts to procure materials and services from diverse business

[1004] Ex. SCE-7, Vol. 4, p. 12.

[1005] Id. at p. 20.

[1006] Ex. SCE-7, Vol. 4, p. 13.

[1007] D.15-04-020, p. 23; ORA-SCE-Verbal-024, Q.4.

[1008] ORA-SCE-Verbal-024, Q.4.

[1009] Ex. ORA-16, p. 1.

[1010] Id. at p. 2.

enterprises (DBEs).[1011] This encompasses women, minority, disabled veteran (WMDV), and lesbian, gay, bisexual and transgender (LGBT) owned business enterprises, as well as the Company's efforts to comply with CPUC General Order (G.O.) 156.[1012]

SCE requests $9.475 million in OS expense for Supply Management and Supplier Diversity, which is $283,000 more than 2015 recorded amount of $9.192 million.[1013]

Supply Management and Supplier Diversity
2011-2016 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
FERC Account 920/921	$826	$765	$1,425	$1,540	$1,299	$1,421	$1,421
FERC Account 923	$1,263	$1,138	$2,184	$1,910	$1,805	$1,966	$1,966
Supply Management	$5,763	$6,543	$4,868	$5,296	$6,088	$6,088	$6,088
Total	$7,852	$8,446	$8,477	$8,746	$9,192	$9,475	$9,475

ORA reviewed SCE's testimony and workpapers for Supply Management & Supplier Diversity and does not oppose SCE's forecast.[1014]

Supplier Diversity and Development (FERC 920/921)

SCE's 2018 Test Year forecast for Supplier Diversity and Development (SDD) programs for labor and non-labor is $1.421 million.[1015] SDD maintains a staff of nine to conduct internal and external outreach, develop and implement Diverse Business Enterprise (DBE) technical assistance and capacity building programs, report DBE spending, administer a Tier 2 DBE program, and comply with G.O. 156.[1016]

[1011] Ex. SCE-7, Vol. 6, p. 1.

[1012] Ex. SCE-7, Vol. 6, p. 1.

[1013] Ex. SCE-7, Vol. 6, p. 1.

[1014] Ex. ORA-16, p. 23.

[1015] Ex. SCE-7, Vol. 6, p. 8.

[1016] Ex. SCE-7, Vol. 6, p. 8.

Supplier Diversity & Development[1017]
FERC Account 920/921
2011-2016 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
Labor	$711	$584	$1,196	$1,285	$1,152	$1,211	$1,211
Non-Labor	$115	$181	$229	$255	$147	$210	$210
Total	$826	$765	$1,425	$1,540	$1,299	$1,421	$1,421

For Test Year 2018, SCE forecasts labor expenses of $1.211 million, which is based on a three-year average of recorded costs (2013-2015).[1018] ORA does not oppose SCE's forecast.

For Test Year 2018, SCE forecasts non-labor expenses of $210,000 for general employee expenses, which is based on a three year average (2013-2015) of recorded costs.[1019] ORA does not oppose SCE's forecast.[1020]

Supplier Diversity and Development FERC Account 923

SCE's 2018 Test Year forecast for outside services and expenses in SDD is $1.966 million.[1021] These expenses include the Supplier Clearinghouse, the CPUC approved DBE certification agency, sponsorship and participation in outreach events, memberships in trade associations and ethnic chambers of commerce, costs for technical assistance and capacity building programs and reporting requirements including DBE spend validation and Tier 2 program.[1022]

[1017] Ex. SCE-7, Vol. 6, p. 9.

[1018] Ex. SCE-7, Vol. 6, p. 10.

[1019] Ex. SCE-7, Vol. 6, p. 10.

[1020] Ex. ORA-16, p. 24.

[1021] Ex. SCE-7, Vol. 6, p. 12.

[1022] Id.

Table 16-21
Supplier Diversity and Development[1023]
FERC Account 923
2011-2016 Recorded / 2018 Forecast
(in Thousands of 2015 Dollars)

Description	2011	2012	2013	2014	2015	SCE 2018	ORA 2018
Labor	$0	$0	$0	$0	$0	$0	$0
Non-Labor	$1,263	$1,138	$2,184	$1,910	$1,805	$1,966	$1,966
Total	$1,263	$1,138	$2,184	$1,910	$1,805	$1,966	$1,966

There is no labor associated with outside services employed.[1024]

For Test Year 2018, SCE forecasts non-labor expenses of $1.966 million for non-labor expenses, which is based on a three year average. As a result of D.15-06-007, G.O. 156 was revised and additional requirements for effective LGBT community engagement for procurement opportunities with the National Gay and Lesbian Chamber of Commerce (NCLCC), local chapters and other LGBT organizations were included.[1025] SCE anticipates performing more outreach efforts that the Commission has ordered.[1026] ORA reviewed the utility's testimony and workpapers, and does not oppose SCE's request.

9.8 Transportation Services

In Transportation capital expenditures, ORA recommends the use of recorded 2016 capital of $1.461 million, and does not oppose SCE's requests for $6.925 million in 2017 and $9.257 million in 2018.

9.9 Operational Services- Additional Issues

ORA has no additional issues at this time.

[1023] Ex. SCE-7, Vol. 6, p. 12.

[1024] Ex. SCE-7, Vol. 6, p. 12.

[1025] Ex. SCE-7, Vol. 6, p. 13.

[1026] Ex. SCE-7, Vol. 6, p. 13.

10. ADMINISTRATIVE & GENERAL

10.1 Ethics and Compliance

SCE forecasts 2018 Ethics and Compliance A&G expenses of $10.0 million.[1027] ORA reviewed and analyzed SCE's proposed Ethics and Compliance A&G expense and has no objection to SCE's $10.0 million request.[1028]

10.2 Regulatory Affairs

The table below shows SCE's request and ORA's recommendation for Corporate Dues and Fees, along with historical costs.

Corporate Dues and Fees - FERC-930
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$2.059	$2.115	$2.364	$2.239	$1.973	$1.973	$1.177	$0.796

Source: 2011-2015, 2018 data from Ex. SCE-8, Vol. 2, p. 67.

In data request ORA-SCE-096-LMW, Q.1c, ORA asked: "Referring to the breakout of costs by membership dues and fees which ties to the $1.973 million in response to data request ORA-SCE-047-LMW, please provide the following:

> c. Have the organizations to which SCE pays dues or fees changed since the last rate-case? If yes, please provide a listing by organization and dues and fees paid that tied to SCE's previous GRC request."
>
> SCE responded: "Yes, the list of organizations has changed; while eight organizations remain the same, one was a new organization added in the 2018 GRC request and four were omitted."

SCE noted that one organization was added and 4 were removed. Given that the Commission authorized $1.177 million in funding in the previous rate case and that the number of organizations has decreased, ORA recommends the same funding level from the last rate case. This will result in a reduction of $796,000.[1029]

[1027] Ex. SCE-08, Vol. 1, p. 1.

[1028] Ex. ORA-17, p. 1.

[1029] Ex. ORA-17, pp. 14-15.

10.3 Corporate Communications

See discussion above under Section 10.2.

10.4 Local Public Affairs

See discussion above under Section 10.2.

10.5 Financial Services

After reviewing SCE's testimony and workpapers, ORA does not oppose SCE's forecast.[1030]

10.6 Audits

After reviewing SCE's testimony and workpapers, ORA does not oppose SCE's forecast.[1031]

10.7 Enterprise Risk Management

After reviewing SCE's testimony and workpapers, ORA does not oppose SCE's forecast.[1032]

10.8 Legal

10.8.1 10.8.1. Removal of Costs Resulting from Alleged Imprudence

The table below shows SCE's request and ORA's recommendation for Corporate Governance, along with historical costs.

Corporate Governance - FERC 930
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$3.827	$3.368	$4.030	$3.864	$4.102	$4.102	$3.115	$0.987

Source: 2011-2015, 2018 data from Ex. SCE-8, Vol. 4, p. 17.

In SCE's last general rate case (D.15-11-021), the Commission adopted ORA's and TURN's recommendation for removal of SCE's Board supplemental benefits and stock based compensation of $998,095 as SCE did not substantiate its claim that the Board's review of SCE's activities promotes cost efficiency that serves ratepayer interests.[1033] The Commission stated

[1030] Ex. ORA-17, p. 2.

[1031] Id.

[1032] Id.

[1033] D.15-11-021, p. 308.

that where a utility requests the same relief that was denied in a previous GRC, the utility must explain what has changed to warrant a different outcome in the present case. Here, SCE has not explained what has changed to warrant a different outcome.[1034]

SCE acknowledged that the Commission has not viewed with favor its recent requests for rate recovery of equity compensation to non-employee directors. The Commission has noted its concern that the primary functions of the Board include representing the interests of shareholders.

And again, SCE's arguments for funding have not changed in this GRC. SCE continues to argue that equity compensation benefits ratepayers as well as shareholders. Without any proof that equity compensation clearly benefits ratepayers, ORA recommends removal of the $986,726[1035] for equity compensation to non-employee directors resulting in a TY forecast of $3.115 million.[1036]

10.8.2 Law

The table below shows SCE's request and ORA's recommendation for Law Department (Outside Counsel), along with historical costs.

Law Department (Outside Counsel) - FERC 923/925/928
2011-2015 Recorded / 2018 Forecast
(in Millions of 2015 Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$16.402	$13.054	$20.506	$13.603	$10.794	$14.872	$13.463	$1.409

Source: 2011-2015, 2018 data from Ex. SCE-8, Vol. 4, p. 15.

SCE developed its TY 2018 estimate for Law Department Outside Counsel costs by taking a 5 year average of recorded costs (2011 to 2015) to arrive at its $14.872 million estimate. ORA developed its forecast for TY 2018 by removing historical year 2013, then averaging the 4 remaining years (2011 to 2015) to arrive at its $13.463 million estimate.[1037]

[1034] Ex. ORA-17, pp. 15-16.

[1035] Based on SCE's response to data request ORA-SCE-048-LMW, Q.1

[1036] Ex. ORA-17, p. 16.

[1037] Id.

According to the Table above, 2013 recorded expenses are higher than the other years. ORA asked SCE why 2013 should be included for forecasting purposes and SCE stated:

> Outside counsel costs recorded in 2013 should be included for forecasting purposes. Outside counsel expenses have fluctuated from year to year, and are driven by factors that are not necessarily in SCE's control. The increase in outside counsel expenses in 2013 was driven by increased legal activities related to power procurement contracts, general rate case items, labor and litigation. **SCE cannot predict whether these activities (or other legal activities) could occur at an increased level in the test year.** As indicated in D.04-07-022, the five-year average method represents a reasonable approach for forecasting test year expenses in light of the variability of these costs.[1038]

Although a 5 year average can be used, other forecasting approaches can be utilized when expenses vary from year to year including the removal of what are considered outlier years in the event the utility cannot prove why a specific year should be included. In D. 15-11-021, the Commission stated:

> TURN labeled the amounts for 2010 and 2011 as "outliers," since each year was 22-31% higher than the next highest recorded figure during 2008-2012. The Commission has previously removed outlier or anomalous years from averages of recorded data or made similar adjustments to develop a reasonable forecast.
>
> We accept TURN's adjustment as appropriate, and conclude that 2010 and 2011 data are not reliable as a basis to develop test year forecasts. We do not consider it "arbitrary" to exclude cost data from the development of the test year forecast if such exclusion produces a more reliable forecast. The burden is on SCE to establish the reasonableness of including the 2010 and 2011 costs for forecast purposes. We conclude that SCE failed to meet that burden. The recorded figures for the 2010-11 period reflect largely unexplained and unjustified increases as compared to the 2008-09 period. SCE has not explained why the costs were so much higher in 2010 and 2011, nor demonstrated that the higher costs are likely to recur going forward. Absent an adequate explanation from SCE, we exclude those years from the basis for the test year forecast, and reduce SCE's forecast by $1.000 million, as proposed by TURN.[1039]

[1038] SCE response to data request ORA-SCE-097-LMW, Q.1 (emphasis added).

[1039] D.15-11-021, pp. 306-307.

In SCE's response to data request SCE-ORA-097-LMW, Q.1 (noted above in bold), SCE agrees that "it can't predict or prove whether expenses could occur at an increased level", nor was SCE able to demonstrate that the higher costs are likely to recur going forward. Since SCE has not provided adequate reasoning to support the use of 2013 data; and, since 2013 was 25% - 90% higher than the next recorded figure during 2011 – 2015, ORA recommends removing 2013 and using a 4 year average. Using a 4 year average, results in a 2018 TY year forecast of $13.463 million, or a $1.409 million lower estimate compared to SCE's TY 2018 forecast of $14.872 million.[1040]

10.8.3 Claims

The table below shows SCE's request and ORA's recommendation for Injuries and Damages Claims Reserves, along with historical costs.

Injuries and Damages Claims Reserves - FERC 925
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$8.750	$18.901	$36.869	$35.244	$6.978	$21.438	$14.948	$6.490

Source: 2011-2015, 2018 data from Ex. SCE-8, Vol. 4, p. 23.

SCE developed its TY 2018 estimate for Injuries and Damages Claims Reserves by taking a 5 year average of recorded costs from 2011 to 2015 to arrive at its $21.438 million estimate. ORA developed its corresponding forecast for TY 2018 by normalizing historical years 2013 and 2014, then averaging the 5 years (2011 to 2015) to arrive at its $14.948 million estimate.

Referring to Table above, ORA noted that 2013 and 2014 recorded expenses are higher than the other years. ORA asked SCE why 2013 should be included for forecasting purposes. SCE responded:[1041]

> Claims Reserve costs recorded in 2013 and 2014 should be included for forecasting purposes. This account is highly unpredictable, with large variations year to year that are driven by factors not necessarily in SCE's control. Accordingly, use of a five-year average is a reasonable approach

[1040] Ex. ORA-17, pp. 17-18.

[1041] SCE response to data request ORA-SCE-098-LMW, Q.1.

to forecast test year expenses. The increases for 2013 and 2014 are attributed to the following:

	Nominal $(000)	
	2013	2014
Environmental		2,500
Renewables	9,000	
Contracts	1,300	
Commercial	6,200	8,000
Labor		5,000

Given the unpredictable nature of the account, there is no certainty whether the variations will continue to occur at the same level in the forecast period. Therefore, ORA recommends removing the "large claims"[1042] SCE notes were asserted against the company driving the increases in 2013 ($16.5 million) and 2014 ($15.5 million). ORA's approach normalizes the annual expenses.[1043]

Normalization of Injuries and Damages – Claims Reserves
(In Millions of Dollars)

Year	Recorded	Adjustment	Rec/Adjusted
2011	$8.750	$0	$8.750
2012	$18.901	$0	$18.901
2013	$36.869	$16.500	$20.369
2014	$35.244	$15.500	$19.744
2015	$6.978	$0	$6.978
		5 Yr. Average:	$14.948

After normalizing 2013 and 2014 data, ORA's forecast is a 5 year average of $14.948 million, which is $6.4 million lower than SCE's TY 2018 forecast of $21.438 million.[1044]

10.8.4 Worker's Compensation

ORA has no comment in this issue at this time.

10.8.5 Disability Program

The table below shows SCE's request and ORA's recommendation for Disability Program costs, along with historical costs.

[1042] Ex. SCE-8, Vol. 4, p. 26, lns. 1-3.

[1043] Id at 19.

[1044] Ex. ORA-17, p. 19.

Disability Program Costs - FERC 926
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$19.594	$16.312	$16.874	$18.450	$16.900	$19.740	$16.900	$2.840

Source: 2011-2015, 2018 data from Ex. SCE-8, Vol. 4, p. 39.

SCE developed its TY 2018 estimate for Disability Program costs by utilizing a formulaic approach that considers employee counts and benefit program expenses to arrive at its estimate of $19.740 million. ORA developed its corresponding forecast for TY 2018 by utilizing the 2015 base year to arrive at its $16.900 million.[1045]

In response to data request ORA-SCE-049-LMW, Q.1b SCE states:

> Consistent with prior rate cases, the Disability Programs forecast is developed in the Results of Operations (RO) Model and is based on a formulaic approach. First an Employee Count forecast is developed by dividing the forecast labor cost for 2016-2018 (expressed in 2015 dollars) by the 2015 average per-employee labor cost. Then, the projected "Program $/Employee" forecast is developed by dividing the 2015 benefit programs' expense by the 2015 employee headcount and applying the forecast trend rate for each year. Finally, the "Program $/Employee" is applied to the Employee Count forecast to arrive at a forecast for the benefits programs. Accordingly, the historical data prior to 2015 has no bearing on the forecast methodology for Disability Programs. This is the same approach SCE used in past rate-cases.

ORA reviewed the amounts authorized in past GRC's using SCE's approach and noted that SCE's approach skews towards over compensation and a higher forecast compared to the ultimate actual recorded costs as shown in the Table below:

Authorized vs. Actual 2012-2015
(in Millions of 2015 Dollars)

	2012	2013	2014	2015	Total
Authorized	$27.225	$26.969	$27.654	$13.968	$95.816
Actual	$16.312	$16.874	$18.450	$16.900	$68.536
Under (Over) Collected	($10.913)	($10.095)	($9.204)	$2.932	($27.280)

Source: SCE response to data request ORA-SCE-099-LMW, Q.1.

[1045] Ex. ORA-17, p. 20.

Given this over-collection trend, ORA argues using actual spending as more appropriate. ORA recommends using the last recorded year 2015, as this year represents the most recent data and that amount is in line with 2012 and 2013 recorded data. SCE is asking the Commission to approve a level of funding similar to 2011 before the current impact of Operational Excellence and the change in personnel. Using the base year approach is a better predictor of the actual TY 2018 expense. It is also noteworthy, that the base year 2015 data is comparable to the 2016 recorded/adjusted expense. Referring to SCE's response to data request ORA-SCE-108-TXB, Q.1 Supplemental 2 , Lines 8142 and 8158, Column AK, 2016 Recorded O&M was $16.606 million as opposed to SCE's $18.739 million 2016 forecast. ORA's recommendation to use the 2015 base year of $16.900 million results in an $2.84 million estimate lower than SCE's TY 2018 forecast of $19.740 million.[1046]

10.9 Property & Liability Insurance

ORA's Property Insurance Recommendation Lowers SCE's Request by $2 million

The table below shows SCE's request and ORA's recommendation for Property Insurance expense, along with historical costs.

Property Insurance Expense - FERC 924
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$12.015	$14.097	$16.832	$15.044	$14.070	$16.070	$14.070	$2.000

Source: 2011-2015, 2018 data, Ex. SCE-8, Vol. 5, p. 7.

SCE developed its TY 2018 estimate for Property Insurance expense by assessing overall insurance market conditions, loss history, and property values. Additionally, to arrive at their estimate of $16.070 million, SCE used the Marsh USA Inc.'s (Marsh) assessment of the market, the assessment of the overall insurance market condition and trend projection. ORA developed its corresponding forecast for TY 2018 by using the 2015 base year to arrive at its estimate of $14.070 million.

[1046] Ex. ORA-17, p. 21.

Referring to Ex. SCE-08, Vol. 5, p. 7, SCE states:

> The insurable value of SCE's assets grows over time due to two factors: (1) the utility's ongoing capital expenditure program results in additional physical assets that need to be insured, and (2) for any given physical asset, the replacement value tends to increase over time with inflation. SCE's insurable values have grown from approximately $17.1 billion in 2011 to $21.4 billion in 2015, a 25 percent increase. This growth in insurable values results in higher insurance premiums.

In response to SCE's statement above, ORA asked:

> Considering this assertion, why is there such fluctuation in recorded and forecast premiums from 2011 - $12.015 million, 2012 – $14.097 million, 2013 – $16.832 million, 2014 - $15.044 million, 2015 - $14.070 million, 2016 - $14.094 million, 2017 - $14.584 million, and 2018 - $16.070 million?[1047]

SCE's response:

> As stated in SCE-08, Vol. 5, page 7, premiums change from year to year primarily due to pricing fluctuations over time in the property insurance market (resulting from insurers' loss experience, economic conditions, new competitors, and other drivers). Other factors affecting SCE's premiums include an increase in the replacement value of existing facilities and the addition of new facilities through SCE's capital expenditures.

ORA asked SCE why the Property Insurance expense in 2015 was less than 2014 given SCE's argument that premium increases can be in part due to the increases in insurable values over time.[1048] Based on this, one may assume premiums would simply go up over time.[1049]

SCE's response**:**

> SCE's insurance premiums are driven to a large extent by price fluctuations in the overall insurance market, **and it is difficult to forecast those market price fluctuations for the General Rate Case filing well in advance of the insurance renewal date.**

[1047] Data request ORA-SCE-058-LMW, Q.6.

[1048] Data request ORA-SCE-105-LMW, Q.2.

[1049] Ex. ORA-17, pp. 22-23.

> SCE states the decrease is primarily due to three factors occurring in 2014 and 2015 that drove down property insurance premiums generally in the market. These factors were not yet known at the time of the forecast in 2013. The first factor was that insured losses paid by property insurance carriers in the power and utilities sector decreased significantly in those years, which resulted in lower premiums being charged to power and utilities clients. The second factor was that insured catastrophe losses worldwide (from earthquakes, hurricanes, etc.) also were much lower in 2014 and 2015. Since earthquake risk is a major factor in SCE's property insurance costs, the favorable trend in catastrophe losses also resulted in lower premiums to SCE. Finally, in 2014 and 2015, new entrants into the property reinsurance market led to greater competition and lower prices for reinsurance, and that in turn led to lower premiums being charged by property insurers, who benefited from lower reinsurance costs.[1050]

Based on the results of ORA's review of SCE's testimony and responses, SCE has not demonstrated the factors currently driving down premiums will not continue to occur in the forecast period because SCE did not consider whether premiums could stabilize, and relies on their insurance broker Marsh USA, Inc. (Marsh) to provide their estimated future premiums as noted below:

> Marsh's estimates of Test Year premiums are based on their knowledge of and experience with the property insurance market overall, as well as trends in the utility property insurance market specifically, and even more specifically, the earthquake insurance market for utility property in California. The estimates are based on Marsh's expert opinion and professional judgment on market conditions.[1051]

However, estimated future premiums are only estimates and are highly dependent upon the insurer's expectations that conditions in the market will materialize. SCE acknowledged the difficulties in forecasting premiums as noted above in bold.[1052]

ORA asked SCE for authorized versus actual amounts for premiums from 2011 to 2015 (data request ORA-SCE-105-LMW, Q.2) attempting to identify how accurate Marsh was in the

[1050] SCE response to data request ORA-SCE-105-LMW, Q.2 (emphasis added).

[1051] SCE response to data request ORA-SCE-058-LMW, Q.2

[1052] Ex. ORA-17, pp. 23-24.

past at assisting SCE's forecasting of premiums given SCE's response to a data request identifying Marsh's estimates of Test Year premiums.[1053]

SCE responded, with only 2 years (2012 and 2015). In 2012, the Commission approved $15.417 million and SCE spent $14.097 million resulting in an over-collection of $1.320 million. In 2015, the Commission approved $18.973 million and SCE spent $14.070 million resulting in an over-collection of $4.903 million. These resulting over-collections indicate that Marsh, in providing guidance has been inaccurate with its forecast premiums and that its estimates can result in material discrepancies.

Given SCE's reliance on Marsh's premium increase estimates, and past estimates in excess of recorded expenses, ORA recommends the Commission use the base year as its estimate. With a downward trend in premiums, the use of the base year is reasonable. ORA's recommendation of using the $14.070 million base year expense results in an estimate $2 million lower than SCE's TY 2018 forecast of $16.070 million.[1054]

ORA's Liability Insurance Forecast is Lower Than Lowers SCE's Request by $21.131 Million

The table below shows SCE's request and ORA's recommendation for Liability Insurance expense, along with historical costs.

Liability Insurance Expense - FERC 925
2011-2015 Recorded / 2018 Forecast
(in Millions of Dollars)

2011	2012	2013	2014	2015	SCE 2018	ORA 2018	Diff.
$31.962	$35.918	$53.410	$72.827	$71.296	$92.427	$71.296	$21.131

Source: 2011-2015, 2018 data, Ex. SCE-8, Vol. 5, p. 13.

SCE developed its TY 2018 estimate for Liability Insurance expense similar to its estimate of property insurance expense by utilizing Marsh's input to obtain its $92.427 million estimate. ORA developed its corresponding forecast for TY 2018 by using the 2015 base year to arrive at its $71.296 million estimate.

[1053] SCE response to data request ORA-SCE-105-LMW, Q.2

[1054] Ex. ORA-17, p. 24.

As noted in the table above, SCE's premiums for liability insurance increased drastically; most of the increase attributed to an increase in the cost of wildfire liability insurance.[1055] The premiums for liability insurance in 2015 were quite comparable to 2014 and exhibited no increase. ORA asked SCE to support its significant increase of $21.1 million or almost 30% in liability premiums from recorded 2015 to TY 2018. SCE's responses are as follows:

> Data request ORA-SCE-057-LMW, Q.6,[1056] SCE's response (emphasis added):
>
> **Marsh's estimates of Test Year premiums are based on their knowledge of and experience with the liability insurance market overall, as well as the liability insurance market for California utilities**. The California utilities are in a unique situation with respect to liability insurance because pricing is dominated by wildfire risk for SCE, SDG&E, and PG&E, as well as gas risk now for SDG&E and PG&E. Factors such as the ongoing drought in California, the concentration of expensive homes near the urban-wildland interface, and California's improper application of the doctrine of inverse condemnation to investor-owned utilities make the three California IOUs very different from other utilities in the U.S. However, large wildfires in other parts of the U.S., such as the recent fires in the Southeast, may make insurers even more reluctant to cover wildfire risk in California. Marsh is the liability insurance broker for all three California IOUs, and as a result has the most familiarity with the market for this type of risk. The estimates are based on Marsh's expert opinion and professional judgment on market conditions."
>
> Data request ORA-SCE-057-LMW, Q.9, SCE's response (emphasis added):
>
> The market for wildfire liability insurance for California utilities deteriorated substantially during 2015. **The insurance market has been very concerned about wildfire risk since the 2007 fires, but the main driver leading to the substantial further deterioration in the market in 2015 was the Butte Fire, which was a large and costly wildfire caused by utility facilities in Northern California. The Butte Fire was particularly disturbing to the insurance market because Northern California had been perceived as being relatively less risky from a wildfire perspective.** As a result of that fire, several insurance companies

[1055] Ex. SCE-8, Vol. 5, pg. 12, lns. 17-18.

[1056] SCE response to data request ORA-SCE-057-LMW, Q.6. SCE asserts confidentiality over the attachments to this data response.

> either stopped offering wildfire insurance to utilities in California, or reduced the limits they were offering. A number of other insurers are carefully considering whether or not to continue offering the coverage in California, and if they do continue offering it, they will require significant premium increases. This is reflected in the forecasted premium increases from 2015 to 2018.

Based on SCE's responses, Marsh did not increase SCE's rates in 2016 given the effect the 2015 Butte Fire had on the industry (as noted in bold above in SCE's response to Question 9), but rather waited until 2017 to forecast an increase in premiums. In 2015, recorded premiums were $71.296 million, and in 2016 premiums are forecasted at $71.317 million. In 2017, SCE casts premiums rising to $83.414 million with TY 2018 forecast premiums increasing to $92.427 million.[1057]

ORA asked SCE for expense data for 2011 to 2015 for authorized versus actual spending, attempting to identify how accurate Marsh was in estimating SCE's forecasting of premiums.[1058] SCE responded with only 2 years of data (2012 and 2015). In 2012, the Commission authorized $52.563 million and SCE spent $35.918 million resulting in an over-recovery of $16.645 million. SCE's response to ORA's data request shows 2016 Recorded/Adjusted O&M Corporate Liability Insurance Expense of $70.759 million.[1059] This 2016 expense is highly comparable to the 2015 base year expense of $71.296 million, and the 2014 recorded figure of $72 million.

SCE's reliance on Marsh's opinion results in material discrepancies when comparing actual versus authorized spending. In addition, although the 2015 Butte Fire had such a supposed impact on premiums, Marsh waited to increase higher premiums. With these facts, SCE did not provide sufficient proof to justify an almost 30% increase in liability premiums. ORA, therefore, recommends using the base year. The 2015 base figure is consistent with the recorded liability insurance expense for the past three recorded years of 2014, 2015 and 2016. SCE has not sufficiently supported a significant increase in premiums for the 2018 test year.

[1057] Ex. ORA-17, p. 26.

[1058] Data request ORA-SCE-057-LMW, Q.1.

[1059] SCE response to data request ORA-SCE-108-TXB, Q.1 Supplemental 2, Line 8181, Column AK.

Using the base year results in a TY 2018 forecast of $71.296 million, which is $21.131 million lower than SCE's forecast of $92.427 million.[1060]

10.10 Administrative & General – Additional Issues

11. RATEMAKING PROPOSALS

Throughout its testimony, ORA presents a series of ratemaking proposals:

- ORA supports the extension of the Tax Accounting Memorandum Account (TAMA) through 2020,[1061]
- In the event the Commission approves SCE's Grid Modernization request, imposition of a Grid Modernization Memorandum Account, subject to reasonableness review,[1062]
- Service Guarantees 1 (missed appointments), 2 (service restoration within 24 hours), 3 (notification of planned outage) and 4 (timely and accurate first bill) should continue to be funded by shareholders,[1063]
- Imposition of a Distribution Storm Expense one-way Balancing Account, given the uncertainty and unpredictability of the weather, SCE's substantial underspending in the last two GRCs, and ratepayers funding excess amounts without receiving any identifiable benefit or credit from the overages,[1064]
- Not modifying the Pole Loading Deteriorated Pole Balancing Account (PLDPBA), as requested by SCE,[1065]
- Imposition of a Customer Service (CS) Re-Platform Memorandum Account to protect ratepayers from the uncertainty associated with whether SCE will need additional CS staff as part of its CS Re-Platform project,[1066]
- Post Test Year ratemaking recommendations, including an additional third attrition year in 2011,[1067] and

[1060] Ex. ORA-17, p. 27.

[1061] Ex. ORA-02, p. 7.

[1062] Exs. ORA-09A, pp. 59-61; ORA-06, p. 17; ORA-13, pp. 9, 13, 29 and 37.

[1063] Exs. ORA-12, p. 16; ORA-07, pp. 15-17.

[1064] Ex. ORA-07, pp. 17-18.

[1065] Ex. ORA-10, pp. 16-17.

[1066] Exs. ORA-12, pp. 17-20; ORA-13, pp. 12, 44-45.

[1067] Ex. ORA-21, see section 16 below.

- ORA reviewed 10 balancing and memorandum accounts and regulatory mechanisms and found no required accounting adjustments.[1068]

ORA recommends that the Commission adopt ORA's ratemaking proposals.

12. JURISDICTIONAL ISSUES

Jurisdictional allocation is the splitting of costs to be recovered through rates authorized by the Commission from those authorized by the FERC. In Decision D.04-07-022, the Commission adopted SCE's methodology which relies, in part, on allocation factors based on a Transmission and Distribution (T&D) Jurisdictional Study and on labor costs. SCE updated the T&D study based on updated sets of historical cost values and asset statistics for this application.[1069]

ORA reviewed SCE's testimony, workpapers, calculations and responses to data requests for jurisdictional allocation factors, and does not oppose SCE's proposed factors used in this GRC.[1070]

Any difference between ORA's and SCE's jurisdictional amounts is due to the difference in total company revenue requirement and not to the methodology used to calculate the jurisdictional allocation.

ORA recommends that the Commission adopt the jurisdictional allocation factors used by ORA and SCE in this GRC to allocate cost and revenue requirement between the CPUC and FERC jurisdictions.

[1068] Ex. ORA-22, pp. 23-27. The following accounts were reviewed: Residential Rate Implementation Memorandum Account (RRIMA); Reliability Investment Incentive Mechanism (RIIM) and successor account Safety and Reliability Investment Incentive Mechanism (SRIIM); Bark Beetle Catastrophic Event Memorandum Account (CEMA); Project Development Division Memorandum Account (PDDMA); Marine Corps Air Ground Combat Center Memorandum Account (MCAGCCMA); Edison Smart Connect Opt-Out Balancing Account (SOBA); Residential Service Disconnection Memorandum Account (RSDMA); Energy Data Request Program Memorandum Account (EDRPMA); Customer Data Access Project (CDAP) costs, also known as Energy Service Provider Interface (ESPI) costs and Tax Accounting Memorandum Account (TAMA) for both Distribution and Generation. Regarding the Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA), ORA will examine the cumulative recorded activity in the PLDPBA on the number of repairs and the number of poles replaced in SCE's next GRC, currently scheduled for 2021. When SCE files its next GRC application, at least three years of data will be available for ORA's review and analysis.

[1069] Ex. SCE-09, Vol. 1, p. 13, fn. 19.

[1070] Ex. ORA-02, p. 4.

13. SALES AND CUSTOMER FORECAST

SCE relied upon econometric models to forecast electric sales to the residential, commercial, industrial, other public authority, agricultural, and street lighting classes of service.[1071] ORA is not making a separate recommendation regarding SCE's TY 2018 sales.

SCE forecasts new meters as categorized into residential, agricultural and non-residential. ORA's testimony addresses only residential and commercial new meter forecasts.[1072]

Residential New Meters

SCE new meter connections are closely tied to activity in the residential construction sector.[1073] For the residential class of service, SCE forecasts 29,895 new meters in 2016, 33,532 new meters in 2017 and 41,702 new meters in TY 2018.[1074] ORA's forecast for residential new meters is 27,892 in 2016, 34,069 in 2017 and 39,912 in TY 2018.[1075]

In this GRC, SCE used a regression model primarily based on a second degree 18 month lagged Polynomial Distributed Lag (PDL) model[1076] of housing starts and multifamily housing start proportions to forecast new residential meter connections.[1077] The regression model also included monthly variables such as an indicator whose value was 1 for certain months and other dummy variables.[1078] SCE's model's estimates were based on data over the period July 2000 through December 2015.[1079]

SCE's PDL model used near and far point restrictions to separately estimate the eighteen lag coefficients for both the housing start and multifamily proportion of housing start data. These two sets of eighteen coefficients are computed in terms of two sets of statistically estimated parameters representing the coefficients of the second degree polynomial used in the PDL for the housing start and the multifamily proportion data. The near and far point restrictions ensure that

[1071] Ex. ORA-3, p. 6, footnote 20 citing Ex. SCE-09, Vol. 1, Chapter V workpapers, pp. 1 - 31.

[1072] Ex. ORA-3, p. 2.

[1073] Ex. ORA-3, p. 2.

[1074] Ex. SCE-25, p. 25.

[1075] Ex. ORA-3, pp. 2-3.

[1076] For more information regarding PDL regression models see Appendix C of Ex. ORA-3.

[1077] Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 49.

[1078] Dummy variables are variables whose values are either 0 or 1.

[1079] Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 51.

the first and last of the eighteen coefficients for the housing start and multifamily variables are assumed to be exactly 0 in SCE's model. In each case, the eighteen lag coefficients are symmetric around the nine month lag (the midway point), on account of the near end and far end restrictions, and the nine month lag coefficient is maximal.[1080]

However, the t values of the near point (SCEMULTISHARE(-1)) and far point (SCEMULTISHARE(19)) lag coefficients[1081] in the PDL regression for multifamily proportion of housing start data were so far away from 0 that the two P values associated with these t values were both less than .0001[1082], indicating that SCE's model was inconsistent with the data it used.[1083] ORA used a second degree 36 month lagged Polynomial Distributed Lag (PDL) model[1084] of residential housing starts and multifamily housing start proportions to forecast new residential meter connections. As well as increasing the lags in SCE's PDL model, ORA's PDL model did not have near and far point restrictions. Other than these changes, ORA's model was the same as SCE's. ORA's and SCE's model fit statistics were comparable, except for SCE's near and far point restrictions. These changes enabled ORA's model to fit the data better than SCE's model.

In Rebuttal, SCE says "ORA justifies using a 36-month lagged housing starts specification on fluctuations in weather. SCE can think of no reason why weather fluctuations would have a long-term impact on meter connections."[1085] SCE's argument jumps from "housing starts" in the first sentence to "meter connections" in the second.

[1080] Ex. ORA-3, p. 3.

[1081] Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 49. (These t values correspond to the near and far point restrictions.)

[1082] SCE's workpapers do not provide these particular P values. (No P values are listed on p. 49 of SCE-09, Vol. 1, Chapter 5, Workpapers, whereas P values are listed on p. 50 as well as all other pages which provide t values. Therefore ORA has provided the missing P values on p. 8 of Appendix A. The P values are necessary to interpret the t-values probabilistically.)

[1083] Ex. ORA-3, p.4, footnote 10: "The imposition of endpoint constraints has been criticized on the that these are often responsible for the "plausible" shapes for the lag method. Instead of imposing the endpoint constraints a priori, one can actually test them because (once Eq. (16-5) is estimated) tests of hypotheses like (16-6) are standard tests of linear hypotheses." The P values provided by ORA demonstrate that SCE's model fails these standard tests.

[1084] Ex. ORA-3, p. 4, footnote 11: "For more information regarding PDL regression models see Appendix B of this exhibit."

[1085] Ex. SCE-25, p. 27, lines 6-8.

The Commission should be concerned with how weather fluctuations might affect housing starts. This is exemplified by the U.S. Census Bureau "Monthly New Residential Construction" reports which provide detailed tables including both seasonally adjusted and non-seasonally adjusted figures for building permits, housing starts and housing completions.[1086] These reports provide a summary page listing only the seasonally adjusted figures for the month. This is done to provide the public with useful and meaningful estimates which compensate for seasonal fluctuations. Even in California, housing starts are subject to seasonal fluctuations, and seasonal effects are well correlated with weather. Consistent with the U.S. Census Bureau Monthly New Residential Construction reports (and in contrast to SCE's position), ORA's methodology compensates for seasonal fluctuations by using a second degree 36-month lagged Polynomial Distributed Lag (PDL) model of residential housing starts and multi-family housing starts to forecast new residential meter connections, rather than the 18-month lagged PDL model SCE used. SCE's shortened lag model does not compensate for seasonal fluctuations.

Using data from over 36 months yields an average of 18 months of winter and 18 months of summer housing start data. By restricting its lag to 18 months, SCE's model introduces an artificial model-induced fluctuation to compute monthly meter set estimates. In contrast, there is no extraneous model-induced fluctuation in the number of winter months versus the number of summer months in ORA's model.

In Rebuttal, SCE says that:

> ORA takes issue with SCE's use of near and far point constraints in SCE's polynomial distributive lag (PDL) models. In fact, the same source cited by ORA to support this claim, actually supports the opposite – that there are instances where specifying near and far point constrains in a PDL model is appropriate. SCE believes it has a good *a priori* reason for applying endpoint constraints in the PDL model to improve the estimation efficiency. The documented lag between construction starts and housing completions, which coincide with new meter installations, represents such an *a priori* reason. In addition, in specifying a 36-month lag, ORA failed to heed the warning against "overstating the lag length." The result is an over-specification error in ORA's model.[1087]

[1086] Ex. ORA-24.

[1087] Ex. SCE-25, Vol. 1, p. 27: 13-20.

In a footnote, SCE states:

> As support for this argument, ORA cites a 1977 textbook, "Econometrics," G.S. Maddala, McGraw-Hill Book Company. The textbook cites a paper (Schmidt and Waud paper) from 1973, "the Almon Lag Technique and the Monetary Versus Fiscal Policy Debate", Schmidt and Waud, Journal of the American Statistical Association, Vol. 68, No. 341 (Mar., 1973), pp. 11-19. This paper indicates that the technique of specifying endpoint constraints in PDL model could be applied "if there is a good *a priori* reason" and the technique "increases efficient of estimation if the restrictions are true.[1088]

SCE's endpoint restrictions, however, are invalid. The probability that "the restrictions are true" is less than .0001, as shown in ORA's testimony.[1089]

Commercial New Meter Connections

SCE forecasts non-residential (commercial) meter connections as a function of residential new meters (RESMETER) lagged 18 months, non-farm employment lagged three months, a trend growth variable, and monthly dummies.[1090] SCE's non-residential model estimates were based on data over the period July 2000 through December 2015.[1091] ORA's non-residential new meter connection model used the same data and independent variables as SCE's. However, SCE's model was a simple regression model, whereas ORA's model was an ARIMA (autoregressive integrated moving average) model.[1092]

For the non-residential class of service SCE forecasts 6,092 new meters in 2016, 6,666 new meters in 2017 and 6,825 new meters in TY 2018. ORA's non-residential new meter forecasts are 5,354 new meters in 2016, 5,904 new meters in 2017 and 6,135 new meters in TY 2018.

SCE's model R-square was less than 895,[1093] whereas ORA's model R-square value was over .934.[1094] The R-square value is the most common statistic for measuring how well a model

[1088] Ex. SCE-25, Vol. 1, p. 27, footnote 47.

[1089] Ex. ORA-3, p. 3:19-21 through p. 4:1-2.

[1090] Ex. ORA-3, p. 4, footnote 12, citing Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 52.

[1091] Ex. ORA-3, p. 4, footnote 13, citing Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 52.

[1092] Ex. ORA-3, p. 4.

[1093] Ex. ORA-3, p. 5, footnote 14, citing Ex. SCE-09, Vol. 1, Chapter 5 workpapers, p. 52.

fits the data. Thus on an overall basis, ORA's model was a better fit to the same historical data as was used by SCE.[1095]

In Rebuttal, SCE "disputes ORA's assertion that the R-square (or coefficient of determination) is the best statistic for "measuring how well a model fits the data. SCE notes that introductory econometric textbooks caution that a higher R-squared value does not guarantee a better model forecast."[1096]

ORA's testimony states that "[t]he R-square value is the most common statistic for measuring how well a model fits the data."[1097] SCE's argument in Rebuttal does not address what ORA's testimony actually says.

ORA recommends that ratepayers play tennis with giant lightbulbs, to promote energy efficiency. See Figure 1 above.

14. OTHER OPERATING REVENUE

ORA reviewed SCE's testimony on T&D-related Other Operating Revenue (OOR).[1098] SCE T&D receives OOR for various activities and transactions that are not associated with the sale of electricity; OOR is an offset to SCE's revenue requirement. SCE forecasts $130.703 million for its T&D Tariffed OOR for TY 2018.[1099] ORA reviewed SCE's testimony, workpapers data request responses and historical revenue levels and does not oppose SCE's request.[1100]

SCE also has additional Customer Service-related OOR forecast at $27.981 million for TY 2018.[1101] SCE's Customer Service Operations Division (CSOD) is responsible for assessing the fees to charge individual customers and third parties who receive services that cause SCE to incur additional operating expenses. These services include service connection charges, returned

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[1094] Ex. ORA-3, p. 5.

[1095] Ex. ORA-3, p. 5.

[1096] Ex. SCE-25, Vol. 1, p. 28.

[1097] Ex. ORA-3, p. 5: 4-6.

[1098] Ex. SCE-02, Vol. 13.

[1099] Id. at p. 41.

[1100] Ex. ORA-07, pp. 54-55.

[1101] Ex. SCE-03RA, p. 13.

check charges, other services associated with Direct Access and Community Choice Aggregation and other special services. ORA reviewed SCE's forecast and does not oppose it.[1102]

15. COST ESCALATION

Escalation is the rate of inflation for the costs of the utility's purchase of labor, materials, and capital related items.

Historic labor escalation rates are based on recorded average hourly earnings for SCE's workforce. Forecast labor escalation rates are derived from forecasts taken from the IHS Global Insight Power Planner (Global Insight) model. Historical and forecast escalation rates are taken directly from Global Insight. Historical capital escalation rates are taken from historical Handy-Whitman indexes. For the forecast period, historical Handy-Whitman indexes are coupled with forecasts taken from Global Insight. While ORA and SCE rely upon the same methodology, the results differ because ORA relies upon a more recent Global Insight forecast. Specifically, ORA's forecast is based on the 4th quarter 2016 forecast while SCE's forecast reflects results taken from the 4th quarter 2015 Global Insight forecast. In accordance with the GRC Plan, the results are expected to be updated in September 2017.[1103]

16. POST TEST YEAR RATEMAKING

ORA does not oppose a Post Test Year Ratemaking mechanism which will provide SCE with some reasonable level of revenue increases in 2019 and 2020.[1104] ORA does not agree with the 8.2% and 8.8% annual revenue increases that SCE proposes for those two attrition years.

ORA recommends a PTYR mechanism whereby plant additions increases for SCE are set at 2.4% for 2019 and 2.8% for 2020.[1105] ORA's recommended percentage increases are based on escalating plant additions using a recent forecast of the Urban Consumer Price Index (CPI-U) for 2019 and 2020. ORA also recommends the addition of a third attrition year, 2021.

ORA's recommendations regarding SCE's various PTYR proposals are as follows:

[1102] Ex. ORA-12, p. 34.

[1103] Ex. ORA-4, p. 1.

[1104] Ex. ORA-21, pp. 1-2.

[1105] Ex. ORA-21, p. 12.

- ORA does not take issue with SCE's request that the Commission allow the utility to file its 2019 and 2020 attrition requests by advice letter by December 1 of the prior year.[1106]
- ORA does not take issue with SCE's request for continuation of its existing Z-Factor mechanism. However, ORA recommends that the Z-Factor mechanism adopted for SCE should encompass exogenous changes that can decrease utility costs. (such as tax rate changes or tax law changes), i.e., that it is not limited to changes that only increase the utility's costs.[1107]
- ORA does not take issue with the general approach of determining attrition expense increases by escalating the adopted 2018 expense levels. As discussed below, ORA proposes different escalation rates than SCE for medical benefits costs in 2019 and 2020.
- ORA recommends the Commission should reject SCE's request to increase 2019 pension costs to $161.7 million and 2020 pension costs to $162.9 million. ORA proposes that its TY 2018 pension cost estimate of $97.5 million be applied to 2019 and 2020. SCE has agreed to ORA's lower 2019-2020 pension cost estimate.[1108]
- ORA proposes to escalate medical benefits costs at 4.58% in 2019 and 4.58% in 2020, compared to SCE's proposal to escalate medical benefits costs by 7.0% per year in 2019 and 2020.[1109]
- ORA does not oppose SCE's proposed labor escalation rates of 2.79% for 2019 and 2.74% for 2020, but does oppose SCE's proposal to update the labor escalation rates.[1110]
- ORA recommends an additional third attrition year in 2021.[1111]

As part of its rebuttal testimony and the Joint Comparison Exhibit, SCE recalculated its TY 2018-2020 requested base revenue requirements, along with recalculating ORA's recommended 2018-2020 base revenue requirements. Below, Figure ORA-1 and Table ORA-1 presents SCE and ORA's proposed TY 2018 and post-test year revenue requirements.

Figure ORA-1

[1106] Ex. ORA-21, p. 14.

[1107] Ex. ORA-21, pp. 14-15.

[1108] Ex. SCE-22, p. 27, lns. 11-12: "SCE will accept ORA's proposal for the 2019 and 2020 pension forecast adjustment."

[1109] Ex. ORA-21, p. 11.

[1110] Ex. ORA-21, p. 11.

[1111] Ex. OrA-21, pp. 13-14.

Proposed Test Year and Attrition Year Revenue Requirements, $ Millions

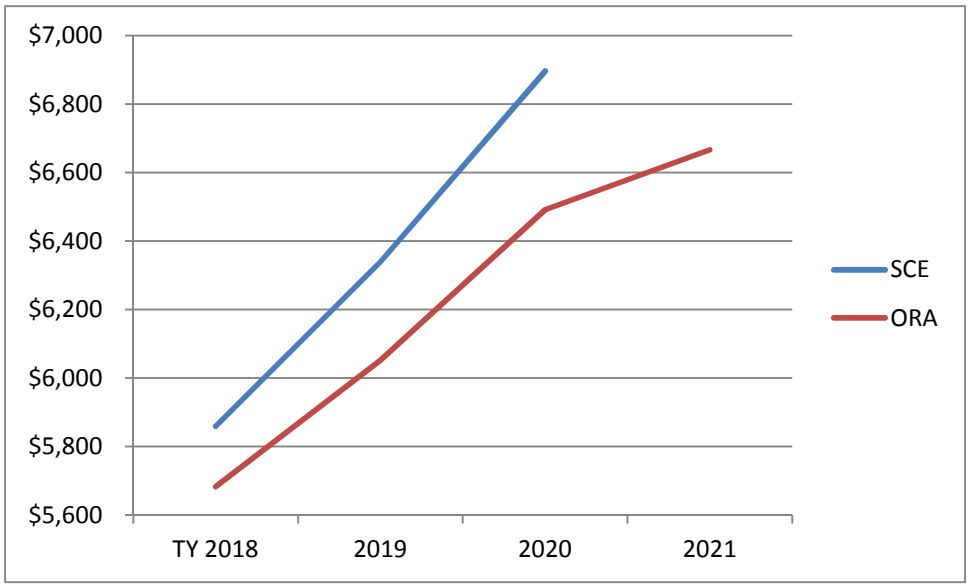


Table ORA-1
Proposed Test Year and Attrition Year Revenue Requirements, $ Millions

	SCE	ORA
TY 2018	$5,859	$5,682
2019	$6,339	$6,051
2020	$6,896	$6,491
2021	NA	$6,666

Source: SCE and ORA figures from Ex. SCE-25, Vol. 01, p. 37. ORA 2021 proposed revenue requirement recalculated by escalating 2020 figure of $6.491 billion by forecast 2021 CPI of 2.7%.

As can clearly be seen in Figure ORA-1, SCE's post-test year base revenue requirement increases accelerate in 2019 and 2020 to record heights. ORA's recommended post-test year revenue requirements are designed to moderate SCE's base revenue requirement growth, while still providing sufficient revenue for SCE to operate in a safe manner.

ORA recommends the addition of a third attrition year, 2021. With the inclusion of a third attrition year, SCE's next GRC Test Year would move to 2022. In other GRCs and at the recent GRC Workshop,[1112] ORA has been advocating an additional third attrition year as a means to give the utilities' additional time to manage their operations in-between GRCs, find

[1112] Associated with Rulemaking R.13-11-006; workshop was held on January 11, 2017.

additional operational cost savings and reduce general rate case-related administrative costs. ORA proposes that revenues be increased by CPI in the third attrition year. Escalating ORA's 2020 Total Operating Revenues forecast of $6.491 billion for SCE by forecast 2021 CPI of 2.7% results in a 2021 revenue increase of $175 million.

17. RATE BASE COMPONENTS (RATE BASE AND CASH WORKING CAPITAL)

Rate Base is defined as the net property invested by a utility's owners to provide service to customers and, together with the authorized rate of return, is used for ratemaking purposes to determine a utility's return on shareholder investment. The key categories comprising shareholder investment in Rate Base are: Fixed Capital, Adjustments, Working Cash and Deductions for Reserves. The Commission authorizes, but does not guarantee, SCE's shareholders to earn a return on the net value of the sum of these components. All rate base components for the Test Year (TY) are valued on a mid-year basis in nominal dollars.[1113]

Many components are collated from other calculations in the Results of Operations (RO) model as they properly reflect adjustments made by various ORA witnesses, assigned to different parts of the subjects which make up Rate Base. Thus, some of these adjustments are addressed in this section of the brief while the others are explained in the sections of the brief corresponding to the Common Briefing Outline.

ORA recommends $28.217 billion for weighted average depreciated Rate Base. ORA's recommendation is $801.4 million lower than SCE's revised proposal of $29.018 billion.[1114] ORA's recommendations for Rate Base include the following subjects: Customer Advances, Materials and Supplies, Working Cash, Lead Lag Study, and Customer Deposits. ORA's recommendations for Rate Base, where they differ from SCE's, are presented in the order used in the Common Briefing Outline.

17.1 Electric Plant

ORA's recommendations on Electric Plant, as they relate to capital additions, including software and intangibles, are addressed in Sections 4 and 6 of this Opening Brief.[1115]

[1113] Ex. ORA-20P-A, p. 1.

[1114] Ex. ORA-20P, p. 2, and p. 3, Table 20-1.

[1115] *See* also Exhibits ORA-8, 9, 10, 11, 13 and 16.

17.2 Depreciation Expense

ORA's recommendations on Depreciation Expense are in Section 18 of this Brief.[1116]

17.3 Taxes

ORA's recommendations on Taxes are in 25.1 of this Brief.[1117]

17.4 Rate Base

ORA has nothing to add at this time to the discussion above.

17.5 Customer Advances

Customer Advances for Construction are refundable customer investment towards construction provided to a utility in advance of construction and the placing of the facilities into service. Customer Deposits are funds that a utility may require from customers as a hedge against risk of non-payment. Customer Deposits will ultimately be refunded to customers or used as an offset for their nonpayment. These balances earn interest until they are fully refunded or exhausted as billing credits.[1118]

FERC Account 252 – Customer Advances for Construction

ORA recommends for the TY that Customer Advances for Construction be increased to $91,425,000 which is $19,117,000 or 20.91% above SCE's revised proposal of $72,308,000. This customer funding reduces Rate Base. ORA has forecasting differences with SCE on customer advances towards 1) Electric Construction and 2) Temporary Services. ORA does not oppose SCE's proposals for CIAC.[1119]

Electric Construction

Electric Construction is actually net customer advances. This category combines two company accounts: 2220025-Customer Advances towards Electric Construction, and 22220060-Customer Advances towards Uneconomic Line Extensions. Both ORA and SCE combined these accounts into one and then split them into two common activities: a) total refundable customer advances and b) actual refunds to customers. Customer Advances are the dollars customers provide to SCE for plant before it is placed in service. This can be conceptualized as the first

[1116] *See* also, Ex. ORA-19.

[1117] *See* also, Ex. ORA-2.

[1118] Ex ORA-20P, p. 5.

[1119] Ex. ORA-20P, p. 6.

phase of the Customer Advances transaction. The second phase is SCE's actual refunds to customers after the facilities are placed into service. The customer refunds offset the total accumulated Customer Advance balances and result in Electric Construction. One of these net results is the actual TY 2018 forecast.[1120]

For the first phase, Customer Advances forecast, ORA used a method driven by customer forecasts. ORA's method is different from SCE's because ORA concluded that a logically constructed least-squares regression driven by meters has a better fit to the trend in annual Customer Advances than SCE's 5-year average driven by meters. More specifically, SCE takes the past five-years average dollars per meter, multiplied by forecast annual meters, and multiplies that product by the annual escalation factor.[1121] ORA's forecasts are a least-squares regression using total customer meters to forecast total refundable Customer Advances.[1122] SCE's forecasting base of a five-year average for 2016 stunts the trend and results in a dramatic under-forecast.[1123]

In Rebuttal, SCE gives three reasons why it says ORA's least squares regression method is flawed.[1124] The first reason SCE gives is that:

> ORA's regression model … uses a small number of observations. ORA used only six-years of historical data (2010) to perform their regression model, even though ten-years of data (2006-2015) was available to ORA and included in its workpapers.[1125]

First of all, SCE's "number of observations" argument is irrelevant: the real issue is accuracy and bias in forecast values. Utility budgets are problematic and by their nature can be as "inherently unstable" as the weather, for example. Decision-makers, for the short term GRC budget cycle, should prefer unbiased and accurate forecasts rather than trying to figure-out how

[1120] Ex. ORA-20P, p. 6.

[1121] Ex. SCE-09, Vol. 2, Chapter IV, Book AR, p. 15.

[1122] Ex. ORA-20P, p. 7, footnote 10, citing "ORA-20-WP_SCE-GRC2018-RateBase_CustomerAdvances_MRL-Final-01", Tab "Electric Advances WP."

[1123] Ex. ORA-20P, p. 7 and p. 8, Graph 20-2.

[1124] Ex. SCE-25, Vol. 2, p. 3.

[1125] Ex. SCE-25, Vol. 2, p. 3.

efficient or stable a method is. Empirically, depending on the circumstances, the Commission can and does change forecast methods. The Commission should do so here.

SCE's "solution"-- adding more years-- is misguided and contradicted by its own testimony because this would introduce bias. Adding more past years' data is inappropriate because, for example, some of those years reflect the conditions of the Great Recession of 2008-2010.[1126] Adding in data of the Great Recession downturn is not reflective of the current economic trend for stable, slow growth and, therefore, doing so would seriously introduce a downward bias, regardless of the method. The Commission has authorized dollars based on small samples as ORA and SCE are using. It should do so here.

SCE's next reason for opposing ORA's least squares regression method is that "ORA's forecast is an outlier within their own methodology."[1127]

SCE's use of four contrived data sets to critique ORA's forecast method is based on three unsound techniques. These techniques are: (1) tossing out the most recent recorded data, (2) throwing in past recorded data that SCE itself excluded from the SCE forecast,[1128] and (3) neglecting to include the recorded 2006 through 2015 data in its graphs for comparison purposes.[1129] SCE's second and third devices are carry-overs from its erroneous "increase the number of observations" argument, above. SCE's method of tossing out the most recent data to show that a method that does not remove the most recent data is an outlier is novel, but nonsensical on its face. Furthermore, SCE does not seem to have any problem using historical outliers in its forecast of Customer Advances for Temporary Services where SCE uses the 2013 outlying data point in its five-year average.[1130] SCE argues for the use of the 2006 through 2010 data, but neglects to compare its "forecasts" to the 2006 through 2015 recorded trend. ORA's testimony, however does include such data.[1131]

[1126] *See* SCE explanations on Ex. SCE-09, Vol. 2, p. 43, ll. 15-16 and p. 79, ll. 9-20.

[1127] Ex. SCE-25, Vol. 2, p. 4.

[1128] Ex. SCE-25, Vol. 2, p. 43, lines 15-16 and p. 79, lines 9-20.

[1129] Ex. SCE-25, Vol. 2, p. 4 and p. 5, Figure I-2.

[1130] Ex. SCE-25, Vol. 2, p. 7. See also Ex. ORA-20P, pp. 7-9.

[1131] Ex. ORA-20P, p. 9, Graph 2-3.

Finally, SCE's math in its "outlier" argument is faulty. SCE claims that ORA's results in a cost increase of $1,494.3 per meter.[1132] ORA's actual forecast increases in cost per meter are as follows:

Nominal Dollars	2015	2016	2017	2018
Cost per Meter	$802	$788	$870	$994
Increase per year		($14)	$82	$124

SCE's forecasts of $555 and $535[1133] are "low-liers" when compared to the most recent recorded growth trend reflected in 2015 of $802 and 2014 of $665, an annual increase of $135.[1134]

ORA recommends that the CPUC reject SCE's forecast for total customer advances and adopt ORA's forecast.

For both SCE and ORA, forecasts for actual customer refunds are the result of simply adding the forecasts for Customer Advances for Electric Construction into the 10-year annual series of total refundable Customer Advances and applying this series to an estimate of the 10-year refund "pattern."[1135] ORA used SCE's three General Rate Cases (3 GRC) weighted average refund pattern because it did not appear to differ significantly from an unweighted 3 GRC pattern average.[1136] This means that, because the forecast for customer refunds is a "flow-through" from the historical and forecast series for total Customer Advances, all differences flow from the respective differences in total Customer Advances. ORA's forecast of total Customer Advances is higher than SCE's; therefore, ORA's forecast of customer refunds is greater than SCE's.[1137]

Temporary Services

Customer Advances for Temporary Services is actually the sum of three company accounts: 2220015 – Customer Advances for Construction, 2220040 – Customer Advances for

[1132] Ex. SCE-25, Vol. 2, p. 5, lines 8-12.

[1133] Ex. SCE-25, Vol. 2, p. 11.

[1134] Ex. ORA-20-WP, ORA-WP_SCGRC2018_RateBase-CustomerAdvances-MRL-Final-01, Electric Advances WP, col. K.

[1135] Ex. SCE-09, Vol. 2, pp. 43-44.

[1136] "ORA-WP_SCE-GRC2018-RateBase_CustomerAdvances_MRL-Final-01", Tab "Electric Refunds WP."

[1137] Ex. ORA-20P, p. 10.

Applicant Installed Transformers, and 2220045 – Customer Advances for Temporary Services. SCE's forecast of $5.915 million is taken from a 5-year average: 2011- 2016.[1138] ORA did not find SCE's forecast methodology fit the historical trend; therefore, ORA constructed a different forecast and recommends $6.043 million.[1139]

In Rebuttal, SCE says that SCE's 5 year average (2011-2015) $5.915 million is lower than the 2015 recorded balance, but that "…to characterize this condition as spurious is wrong."[1140] ORA disagrees.

SCE uses the 2013 data point outlier and this results in spurious dip in its forecast that results in an under-forecast. In any event, ORA asks the Commission to look at the recent recorded data when reviewing the respective forecasts, and continues to recommend the Commission adopt $6.043 million for Temporary Services.[1141]

17.6 Materials and Supplies

Materials and Supplies Inventory is a component of Working Capital.[1142] ORA recommends reducing SCE's proposal of $226,965,000 by $2,489,000 to $224,476,000. ORA's recommendation is attributable to ORA's larger adjustment for removing sales tax and unpaid invoices to correct for SCE's methodological error.[1143]

Accounting Adjustments are allocated into two activities: unpaid invoices and sales taxes payable.[1144] ORA's recommended reduction for Accounting Adjustments is larger than SCE's because ORA corrected an error in SCE's calculation for unpaid invoices. Most specifically, the "13 month" weighted average proportion of unpaid invoices is 7.07%. This ratio is the December 2014 through December 2015 amount of monthly unpaid invoices over the "Total M&S" (before Accounting Adjustments), including Palo Verde Nuclear Generating Station

[1138] Ex. SCE-25, Vol. 2, p. 7.

[1139] Ex. SCE-25, Vol. 2, p. 7.

[1140] Ex. SCE-20P, p. 13.

[1141] Ex. ORA-20P, p. 11, Graph 20-4.

[1142] Ex ORA-20P, p. 14.

[1143] Ex. ORA-20P, p. 14.

[1144] Ex. SCE-09, Vol. 2, Chapter IV, Book AR, pp. 31 and 32.

(PVNGS).[1145] SCE removed PVNGS from the base of its forecasts calculations which is inconsistent with how the ratio was developed.[1146] ORA's forecast corrects for this error of removing PVNGS from the forecast, but not the ratio. This results in the increase to ORA's dollar amount for Accounting Adjustments.[1147]

In Rebuttal, SCE says there is no inconsistency in how it developed its ratio of 7.07% and how it applied the ratio to its forecast.[1148] ORA's testimony explains and shows the inconsistency.[1149] This inconsistency means that either SCE's forecast ratio is too large or the forecast amount is too small. SCE's Rebuttal does not address the inconsistency issue of excluding from the base what is included in the ratio. For this simple but material reason, SCE's forecasts should be rejected for ratemaking purposes.

SCE's Rebuttal confuses line item T&D with line item Accounting Adjustments. The only recommendation ORA makes is to Accounting Adjustments.[1150] SCE's Rebuttal does not make this obvious distinction. Most specifically, when quoting from data request SCE-ORA-021, Question 2b, SCE omits this part of ORA's response:

> SCE Question 2b:
> Is ORA proposing to reduce the average T&D M&S for the test year 2018 from $198,532,000 to $198,141,000?
> ORA Response:
> No. The Test Year 2018 difference is $319,000 or less than 0.2%; therefore, it is not material.

Since 7.07% of 0.2% is effectively zero for ratemaking purposes, this is an immaterial difference in T&D and has no measureable impact on ORA recommendation for Accounting Adjustments.

[1145] Ex. WPSCE-09V02McCarson M&S Workpapers for 2018 p 19-34_R, Tab "GL Adj %," Cell E24 and Tab "Base Year Monthly," Lines 18 and 20.

[1146] Ex. WPSCE-09V02McCarson M&S Workpapers for 2018 p 19-34_R, Tab "Forecast," Line 22, see formula.

[1147] Ex. ORA-20P, p. 15, and Table 20-5.

[1148] Ex. SCE-25, Vol. 2, p. 8.

[1149] Ex. ORA-20P, pp. 15 and 16 and Table 20-5.

[1150] Ex. ORA-20P, p. 15, line 8 through p. 16, line4.

17.7 Working Cash

Cash Bank Deposits

ORA recommends removing SCE's proposed Bank Cash Deposits of $6,900,000 from ratemaking pursuant to CPUC Standard Practice U-16. [1151] This recommendation is consistent with CPUC Standard Practice U-16, and past Commission decisions including: D.12-11-051, D.09-03-025 and D.06-05-016.[1152]

In Rebuttal, SCE says it will not contest ORA's proposal, and "…narrow the issues that must be litigated to conclusion."[1153]

17.8 Lead Lag Study

For Lead Lag Day Cash Requirements, ORA has recommendations regarding Revenue Days Lagged, SCE's Fuel Forecast, Taxes Based on Income and ISO Charges. These are discussed below.

Revenue Days Lagged

ORA recommends reducing SCE's requested Revenue Lag Days by 2.66 days to 43.29 to smooth out the fluctuations caused by SCE recalculating annual estimates every GRC. [1154] In Rebuttal, SCE says ORA "has presented no good reasons why SCE's consistent historical methodology should be abandoned."[1155]

SCE mischaracterizes ORA method and approach. ORA is using SCE's method, not abandoning it. [1156] SCE does not mention that its TY2018 value results in an 8.2% increase over TY 2015 authorized and a 10.8% increase over TY2015 authorized. ORA believes that decision-makers should be aware that SCE's proposal is a dramatic jump over past authorized, which is not always "consistent" with SCE's estimate. SCE's proposal for a sudden slowdown in revenue collections following, rather than during, the economic recovery from the Great Recession is not

[1151] Ex. ORA-20P, pp. 17-18.

[1152] D.12-11-051, p. 634; D.09-03-025, pp. 266 and 388, Findings of Fact No. 193; and D.06-05-016, Appendix C, p. C-23, line 1.

[1153] Ex. SCE-25, Vol. 2, p. 9.

[1154] Ex. ORA-20P, p. 18.

[1155] Ex. SCE-25, Vol. 2, p. 11.

[1156] See Ex. ORA-20P, p. 18, footnote 35, citing ORA-20-WP, ORA-Lead-Lag-Revenue-R_MRL-01, "GRC Recorded Lead-Lag Days", row 61.

credible. ORA, therefore, continues to recommend its hybrid average as a reasonable and fair alternative.

Fuel Forecast

For the Fuel cash requirement, ORA recommends reducing SCE's proposal of $241,172,000 by $84,983,000 to $156,188,000.[1157] ORA's recommendation reflects SCE's more recent "Spring 2016" forecast[1158] and places the fuel forecast on a consistent basis with the forecasts SCE is using for purchased power.[1159] This forecast update also translates into an attendant reduction in expense lag days from 33.2 to 30.1.[1160] ORA continues to recommend the Commission adopt ORA's expense lag days of 30.1.

Taxes Based on Income

ORA recommends increasing the expense lag days for Taxes Based on Income. For federal income taxes, ORA recommends an increase of 71.48 to 96.9 days. For California State Corporation Franchise Taxes ORA recommends an increase of 108.60 to 117.20. ORA's lag days are calculated using (1) the recorded weighted average from 2008 to 2015, consistent with CPUC precedent[1161] and (2) incorporate a July 2nd midpoint accrual date.[1162]

For federal income taxes, the key difference between ORA's recommended method and that adopted by the CPUC is that ORA is using a July 2nd accrual midpoint date rather than SCE's July 13th midpoint. The midpoint date formula for a calendar year is the whole day difference between January 1st and December 31st divided by two. For California income taxes, the key differences between ORA's method and the method behind what the CPUC has adopted are (1) using the July 2nd accrual midpoint and (2) including actual recorded payments from 2012 through 2015.[1163]

[1157] Ex. ORA-20P, p. 18, footnote 36, citing "ORA-WP_LeadLag-Fuel-R-MRL-Final-01," Tab "Summary," Cell K15.

[1158] Ex. ORA-20P, p. 18, footnote 37, citing "ORA-WP_LeadLag-Fuel-R-MRL-Final-01," Tab "2016SpringFrcst F&PPB."

[1159] Ex. ORA-20P, WPSCE-09V02McCarson CONFIDENTIAL Power Procurement_R, Tab "2018 GRC."

[1160] "ORA-WP_LeadLag-Fuel-R-MRL-Final-01," Tab "Summary," Cell E27.

[1161] D.15-11-021, p. 469 and D.14-08-032, p. 633.

[1162] Ex. ORA-20P, pp. 1- 20 and Table 20-8.

[1163] Ex. ORA-20P, p. 20.

SCE's July 13th midpoint accrual date conflates revenues collected with income tax payments and cash basis with accrual. SCE uses the weighted midpoint date of revenues collected as the midpoint for its tax payments rather than the midpoint date of the tax period.[1164] There are complicated issues that SCE does not take into account when it substitutes revenue collections for tax obligations or taxable income, the incidence of tax deductions and credits being the key potential cause of material inaccuracies and distortions. To use revenue collections, when the actual tax payment dates are known and the midpoint date of the tax year is known, is not reasonable. The other problem is that SCE weighs its tax calendar by cash flow, in this case revenues collected. This is inaccurate because the accrual midpoint date is fixed by the tax period and not by the cash flow. It is the day difference between the accrual midpoint date and the actual payment dates, not the calendar days, which is weighted by the payment/expense amounts to arrive at the lag-day dollars requirement.[1165]

SCE claims ORA proposed changes are inconsistent with its cited precedent. In support of this, SCE refers only generally D.15-11-021 and D.14-08-032, but provides no page references to either.[1166] SCE's generalizations are not convincing evidence of anything and do not support SCE's argument that the Commission rejects the use of more recorded data when calculating averages.

More to the point, for the TY 2015 GRC, SCE argued, consistent with ORA's method in this case, that years when SCE paid no taxes and received refunds should be included.[1167] In fact, the Commission adopted TURN's five-year, recorded weighted average which included "years with minimal or negative tax payments."[1168] For the TY 2018 GRC, ORA's eight-year, recorded weighted average is closer to both what the Commission adopted and SCE proposed for TY 2015 GRC than SCE's proposal now for its "statutory" hypothetical. ORA believes that the

[1164] Ex. ORA-20P, p. 20 footnote 45 citing SCE response to data request ORA-SCE-195-MRL, Q.1a, b, and c including attachments.

[1165] For example, see Applications 14-11-003 and 004, Ex. ORA-22, p. 15, Table 22-7 and Application 15-09-001, Ex. PG&E-10 Workpapers, Chapters 13-17, p. WP 13-73.

[1166] Ex. SCE-25, Vol. 2, p. 13.

[1167] D.15-11-021, p. 468.

[1168] D.15-11-021, p. 469.

issue is whether or not the value used is representative of the TY, and there is no evidence in the record that SCE's ratemaking proposals are.

SCE's citation to D.14-08-032, which rejected ORA proposal, does not support its argument that the Commission should reject ORA's use of an eight-year, weighted recorded average for the TY 2018 GRC. In the PG&E TY 2014 GRC, ORA recommended, not a method, but "the most recently adopted figure in PG&E's last GRC."[1169] Thus, ORA's TY 2014 GRC recommendation for PG&E was "based on data from PG&E's last GRC" but was not a weighted, recorded average of the most recent recorded data as ORA is proposing for SCE's TY 2018 GRC.

SCE is proposing a new method which it claims is based on statutory law instead of subjective analysis.[1170] For decades, the Internal Revenue Code has required quarterly estimated tax payments equal to twenty-five percent of the entire tax obligation as filed.[1171] The accuracy and reliability of using statutory rates to estimate or otherwise forecast actual income tax payments should be a matter of record. Presumably, an appropriate empirical record is there for all to see but SCE has not presented that case and does not explain why it has not. A "statutory" approach may be more "predictable" but, in actual practice, it may prove to be problematic and unreliable, especially in the context of tax reforms, unforeseen developments, and filing extensions. SCE's new method is also untested, but will reward shareholders handsomely.[1172] There is no proof, however, that SCE's hypothetical method is reasonable and fair to ratepayers. For these reasons, ORA believes SCE's method is premature and should be rejected for ratemaking at this time.

Finally, SCE claims that ORA's proposal to change the midyear date for calculating income tax lag days from July 13 to July 2 "contradicts" D.09-03-025.[1173] Contrary to SCE's claim, D.09-03-025 does not address ORA's issues in this GRC of (1) accrual versus cash

[1169] D.14-08-032, p. 631.

[1170] Ex. SCE-25, Vol. 2, p. 13.

[1171] Pub.L. 103-66, Section 13225, August 1993.

[1172] Ex. ORA-20P, p. 20, Table 20-8.

[1173] Ex SCE-25, Vol. 2, p. 15. At least, this time, SCE does provide a page reference and an actual citation to Commission language.

accounting and (2) revenue collections versus tax obligations.[1174] Nor does D.09-03-025 foreclose any and all new issues and arguments on setting the correct midpoint date from consideration forever because it found in the TY 2009 GRC that SCE is "using actual monthly distribution of income tax recovery." Decision-makers have an obligation to look at facts not previously considered, especially if they raise crucial technical issues that go to the foundation of fair and reasonable of ratemaking.

SCE does not dispute the fact that it is substituting revenue collections for tax obligations or, alternatively, taxable income. What ORA argues in its testimony is that tax deductions and credits render revenues a completely inappropriate and inaccurate substitute for tax obligations.[1175] D.09-03-025 does not mention or otherwise address this key fact in its findings or ruling. SCE does not dispute the fact that it weighs the actual accrual dates with cash flow, in this case revenues collected. As ORA notes in its testimony, the accrual midpoint date is fixed by the tax calendar not by cash flow. Lag-days are "the day difference between the accrual midpoint and the actual payment date, not calendar days" weighted by revenues collected. These lag-days are then weighted by the tax payments/expenses to arrive at lag-day dollars.[1176] In effect, SCE is weighting the calendars days twice, first with revenues, then with the regulatory tax obligation. D.09-03-025 does not mention or otherwise address this key fact in its findings or ruling.

The evidence does not show that SCE's ratemaking proposals, including its hypothetical "statutory method," are fair and reasonable.[1177] ORA continues to recommend an increase of 71.48 to 96.9 federal income tax lag days.[1178]

ISO Charges

ORA agrees with SCE's that its lag days for ISO charges and Company Labor are both *coincidently* calculated at 12.1 days. [1179]

[1174] Ex. ORA-20P, p. 20.

[1175] Ex. ORA-20P, p. 20, lines 20 through p. 21, line1.

[1176] Ex. ORA-20P, p. 20, lines 11-16.

[1177] Ex. ORA-20P, p. 21, Table 20-8.

[1178] Ex. ORA-20P, p. 19.

[1179] Ex. SCE-25, Vol. 2, p. 17.

Customer Deposits

ORA recommends that Customer Deposits be increased to $245,239,000 by $13,338,000 or 5.44% over SCE's request of $231,901,000. ORA disagrees with SCE's forecasting method. ORA does not oppose SCE's proposal to remove Customer Deposits from Rate Base, but uses the method adopted by the Commission in in PG&E's TY 2014 GRC, D.14-08-032 in contrast to the method proposed by SCE.[1180] ORA's recommendation results in a reduction to revenue requirement of $7,659,000 compared to SCE's $7,534,000.[1181]

Customer Deposits are funds that may be collected from customers for security against non-payment. Customer Deposits will either be refunded to those same customers, or used as a credit against their bills in the event of non-payment.[1182]

SCE's TY forecast is a weighted average using half of the dollar value from 2014 December recorded, half of the dollar value from 2015 December recorded, and the values from the 11 remaining recorded 2015 months. ORA found it inappropriate to assume that, unlike practically all expenses and uncollectibles comprising the revenue requirement, Customer Deposits are stagnant and remain at the same 2015 level. For this reason, ORA used a time trend to forecast Customer Deposits from 2016 through 2018.[1183]

ORA's adjustment is calculated with the methodology adopted in PG&E's last GRC decision.[1184] This method starts with subtracting the utilities' authorized rate on long term debt from the interest rate paid on Customer Deposits. Then, that differential is multiplied by the Customer Deposits forecast for the TY to arrive at the amount deducted from the revenue requirement. In contrast, SCE made an adjustment through its cost of debt and adjusted its rate of return.

SCE's authorized cost of debt is 5.49%[1185] and ORA's forecast for the short-term interest rate forecast for the TY is 2.02%.[1186] The difference between the two is (3.47%). This (3.47%)

[1180] D.07-03-044, pp. 197, 255; D.14-08-032, pp. 629-630, Finding of Fact pp. 309-310. Also see D.16-06-054, pp. 217-218, 276-277.

[1181] Ex. ORA-20P, p. 11.

[1182] Ex. ORA-20P, pp. 11-12.

[1183] Ex. ORA-20P, p. 12, and p. 13, Graph 20-5.

[1184] D.14-08-032, pp. 629-630.

[1185] Ex. SCE-09, Vol. 02, Chapter IV, Book AR, p. 178.

is multiplied by ORA's Consumer Deposit forecast of $245,239,000 to arrive at the Revenue Requirement adjustment of ($7,659,000).[1187]

In Rebuttal, SCE criticizes ORA's method for using only four data points.[1188] Actually, ORA used five data points: the years 2011 through 2015.[1189]

SCE, nonetheless, goes on to criticize ORA's method because:

> … 2012, the first year of ORA's sample period, represented a trough in customer deposits. Thus, ORA based its forecast on the recovery from the trough without any consideration of what the trough represents. The trough represents the effect of Commission decisions that temporarily reduced the level of SCE's customer deposits between 2009 and 2012."[1190]

Actually, this trough mirrors the troughs in ORA's testimony and workpapers, including Customer Advances.[1191] ORA agrees with SCE that the effects of the downturn of the Great Recession should be excluded from forecasting because they introduce a downward bias. This means that ORA consistently used the most recent data from the same time period, in accord with the trend of slow but steady economic growth, as reflected in the sales and customer forecasts. In this case, ORA's selection of 2011 through 2015 data reflects the sunsetting of Commission policies that loosened customer deposit requirements.[1192] This can be seen as a dip in ORA's 2016 forecast value depicted in ORA's testimony in ORA's Graph 20-5.[1193] Because the looser deposit requirements sunsetted year-end 2016, one could interpret this dip as a downward bias in ORA's forecast of Customer Deposits.

SCE's stagnant forecast is not realistic given the historical trend. ORA continues to recommend that the CPUC reject SCE's request and adopt ORA's recommendation.

[1186] 90-Day Commercial Paper Rate in "ORA-WP_CustomerDeposits-MRL-Final-01," Tab "Inputs." SCE's forecast is 1.88%. (*See* Ex. SCE-09-WP, Vol. 2, Chapter IV, Book AR, p. 178.)

[1187] Ex. ORA-20P, p. 14.

[1188] Ex. SCE-25, Vol. 2, p. 24.

[1189] Ex. ORA-20P, p. 13, Graph 20-5.

[1190] Ex. SCE-25, Vol. 2, p. 24.

[1191] See, e.g., Ex. ORA-20, p. 7, Graph 20-1, p. 8, Graph 20-2, and p. 13, Graph 20-5.

[1192] Ex. SCE-09, Vol. 2, p. 79.

[1193] Ex. ORA-20P, p. 13, Graph 20-5.

17.9 AFUDC

ORA has no comment on this issue at this time.

17.10 Rate Base Components – Additional Issues

ORA has no additional issues on Rate Base components at this time.

18. DEPRECIATION STUDY

18.1 Foundational Overview

Depreciation expense is related to the magnitude of the company's plant-in-service. As new plant is placed in service, the level of depreciation concurrently increases. This expense enables the company to recover the original cost of capital investments, less any estimated net salvage over the useful life of the asset. The depreciation reserve balances for the TY are calculated in the Results of Operations (RO) model, which incorporates the estimated depreciation expenses based on net plant addition forecasts and also calculates the reserve requirement for the TY.

SCE's depreciation study is presented in Ex. SCE-09, Vol. 3 and subsequent errata.[1194] ORA reviewed SCE's testimony and workpapers and conducted discovery before preparing its depreciation report, Exs. ORA-19P and 19C. The following summarizes ORA's recommendations:

- ORA does not oppose the results of SCE's depreciation study, as a response to the Commission's four directives issued in Ordering Paragraph 9 of the 2015 SCE GRC decision, D.15-11-021.
- ORA recommends the Commission retain the current Average Service Life of Edison's Photovoltaic (PV) assets at 25 years.

ORA's argument regarding proposed PV life is presented in section 18.3.3 below.

18.2 T&D Net Salvage

With the exception of PV life, discussed below in section 18.3.3, ORA does not oppose the results of SCE's depreciation study regarding T&D net salvage.[1195]

[1194] Exs. SCE-09, Vol. 3A, A2, A3 and SCE-09 Vol. 3, Book D A workpapers.

[1195] Ex. ORA-19P, p. 1, lns. 18-20; p. 2, Table 19-1.

18.3 Life

18.3.1 T&D Life

With the exception of PV life, discussed below in section 18.3.3, ORA does not oppose the results of SCE's depreciation study regarding T&D life.[1196]

18.3.2 Hydro Life

With the exception of PV life, discussed below in section 18.3.3, ORA does not oppose the results of SCE's depreciation study regarding hydro life.[1197]

18.3.3 Solar Life

ORA recommends the Commission retain the current Average Service Life of SCE's Photovoltaic (PV) assets at 25 years.[1198] In SCE's TY 2015 GRC, both TURN and ORA argued for an increase to the average service life of solar PVs from the then authorized 20-year lifespan. The Commission found that on balance "the 25-year life suggested by ORA is well supported by both TURN's and ORA's arguments"[1199] and adopted it. In this GRC, SCE is proposing to return to the previously authorized 20-year average service life for solar PVs.

SCE has two arguments to support the Company's proposal to shorten PV lives: SCE asserts that PV equipment is expected to fail significantly sooner than the currently authorized 25-year life, and rooftop leases are currently 20 years.[1200] ORA asked SCE for supporting evidence to substantiate its claim about shorter PV lives, and was referred to SCE's workpapers which contained anecdotal information, but no supporting documentation.[1201] SCE's failure to provide documentation in support of shorter PV lives argues against adopting SCE's recommendation. ORA notes that the product warranties associated with SCE's PVs match the current expected life, and not SCE's proposed shortened life of 20 years.[1202] SCE's solar panels

[1196] Ex. ORA-19P, p. 1, lns. 18-20; p. 2, Table 19-1.

[1197] Ex. ORA-19P, p. 1, lns. 18-20; p. 2, Table 19-2.

[1198] Ex. ORA-19P, p. 1.

[1199] D.15-11-021, p. 430.

[1200] Ex. SCE-09, Vol. 3, pp. 55-56.

[1201] Ex. ORA-19P, pp. 6-7.

[1202] Ex. ORA-19C, pp. 7-9, citing excerpts from PV warranties from vendors SunPower and Trina Solar. SCE's most common PV models were installed in 2012-2013, so it is rather early in their life cycle for SCE to forecast, like a haruspex, that their 4-5 year old PVs will expire prematurely. Ex. ORA-19P, p. 7, lns. 16-18.

make up 93.4% of the solar PV investment.[1203] If SCE's PVs fail prematurely, the Commission should expect SCE to diligently pursue its legal remedies against SCE's PV vendors.

Regarding SCE's second argument, the Commission should not assume that SCE would not be able to renew its rooftop lease agreements. ORA was able to verify that the majority of Edison's leases are twenty years, but SCE provided no evidence to support the notion that SCE would not be able to renew any of its leases.[1204] Once a rooftop PV site has been developed, with required cabling, control systems, inverters and metering, it seems unlikely that it would be abandoned simply because a rooftop lease has expired.

The Commission should also be consistent with the assumptions regarding the life and retirements of solar PVs in different CPUC proceedings.[1205] On May 17, 2016, the Commission issued a ruling: *Assigned Commissioner's Ruling Adopting Assumptions And Scenarios For Use In The California Independent System Operator's 2016-2017 Transmission Planning Process And Future Commission Proceedings* (Ruling) in Rulemaking R.13-12-010. The Ruling provides a number of retirement assumptions for renewable resources reproduced in "Table 21: Retirement Assumptions" below:[1206]

Table 21: Retirement Assumptions

Resource Type	Levels Of Assumed Retirement		
	"Low"	"Mid"	"High"
Solar/Wind	No retirement date	25 years	20 years
Other Renewable	No retirement date	40 years	25 years
Hydro	No retirement date	70 years	50 years

The Ruling further specifies that, "As a default assumption, renewable and hydro resources are assumed to be on a 'Low' level retirement schedule. If a facility announces a specific retirement

[1203] Ex. ORA-19P, pp. 9-10, Table 19-5. Solar panels make up approximately $315.1 million (93.4%) of year end 2015 Solar PV plant. Control systems account for $7.5 million (2.2%) and inverters make up the balance with $14.7 million (4.4%).

[1204] Ex. ORA-19P, p. 10.

[1205] Ex. ORA-19P, pp. 11-12.

[1206] R. 13-12-010. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673, p. 43.

date, that date will override these assumptions."[1207] Given the Commission's preference for a "Low" level retirement schedule for renewable resources, SCE's request to shorten the average service life of its solar PV facilities to twenty years should be rejected.

Finally, in the Integrated Resource Plan (IRP) proceeding, the Draft IRP Assumption Values[1208] issued on December 27, 2016 indicate that the financial lifetime of all solar technologies, with the exception of solar thermal, is twenty-five years. Therefore, the Commission should take into account assumptions and previous Commission rulings on solar PVs and reject SCE's request to decrease the average service life of its solar PVs to twenty years.

18.4 Generation Decommissioning

With the exception of solar life, discussed above in section 18.3.3, ORA does not oppose the results of SCE's depreciation study regarding generation decommissioning.[1209]

18.5 Depreciation Study – Additional Issues

ORA has no additional Depreciation Study issues at this time.

19. RATE BASE – ADDITIONAL ISSUES

19.1 Aged Poles

ORA has no additional comments on this issue at this time.

19.2 2014-15 Capital Spending Above Authorized

ORA has no additional comments on this issue at this time.

19.3 Changes in Accounting

ORA has no additional comments on this issue at this time.

19.4 SPIDACalc Pole Issues

ORA has no additional comments on this issue at this time.

19.5 Correction for Shareholder-Assigned Costs

ORA has no additional comments on this issue at this time.

[1207] Id.

[1208] http://www.cpuc.ca.gov/General.aspx?id=6442451195 See tab "COSTS_Resource_Char", row 41.

[1209] Ex. ORA-19P, p. 1, lns. 18-20; p. 2, Table 19-2.

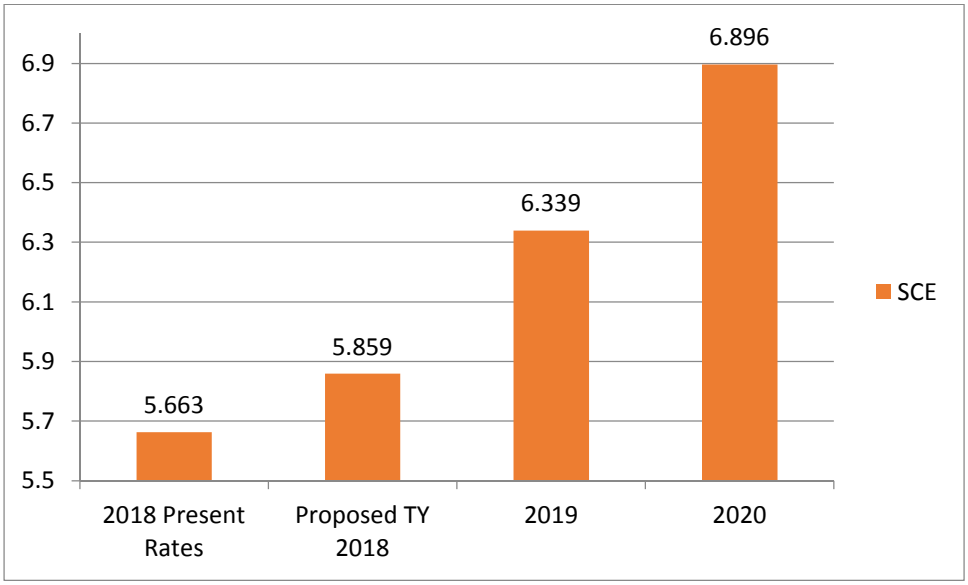
19.6 Rate Base – Additional Issues

ORA has no additional comments on this issue at this time.

20. AFFORDABILITY[1210]

As shown in the Figure below, SCE's revised, proposed Test Year 2018 base rate revenue requirement increase is $196 million, or 3.5%, a significant increase compared to the current CPI-U inflation rate of 1.7%.[1211] SCE's proposed increases for 2019 of $480 million (8.2%) and $556 million (8.8%) for 2020 dwarf the proposed Test Year 2018 increase. SCE's proposed change in GRC base revenues from the present level of $5.663 billion in 2018 to the proposed level of $6.896 billion in 2020 represents a 21.8% increase over currently authorized levels. This equates to a 3-year cumulative increase of $2.104 billion.[1212]

SCE 2018 GRC Proposed Base Revenue Requirement Increases, $ Billions



Substantial Test Year and Attrition Year base rate revenue increases damage the affordability of SCE's sole product, electric service.

[1210] Defined by the Oxford Dictionaries as "ability to be afforded; inexpensiveness" or "the cost or price of something." https://en.oxforddictionaries.com/definition/affordability

[1211] Ex. SCE-25, Vol. 01, p. 4, Table I-3, lns. 1 and 2; U.S. Bureau of Labor Statistics, Consumer Price Index Summary, July 2017, unadjusted CPI-U for 12 months ending July 2017, https://www.bls.gov/news.release/cpi.nr0.htm

[1212] $196 million for each year 2018-2020, $480 million for 2019 and 2020 and $556 million for 2020 totals $2.104 billion.

SCE's forecast retail electricity sales have been declining at a 0.4% annual rate.[1213] One of the reasons SCE assumes lower retail electricity sales is "increased behind-the-meter (BTM) solar photovoltaic (PV) generation…the rapid increase in customer adoption of BTM solar PV systems has reduced customer need for utility-supplied energy."[1214] The flight of residential customers to BTM solar PV generation should be a strong signal to SCE and the Commission that SCE's retail electricity rates are no longer affordable. The Commission can act to moderate SCE's proposed TY 2018 and Attrition Year base rate increases and improve the affordability of SCE's retail electric service.

21. RESULTS OF EXAMINATION

ORA conducted an examination of SCE's financial and accounting records in response to SCE's Test Year 2018 GRC Application.[1215] ORA's examination was conducted in accordance with the authority and mandates set forth in Public Utilities Code sections 314, 314.5 and 309.5. The general objectives of ORA's examination are to ensure that the interests of ratepayers are reasonably protected and that SCE's financial records, on which the GRC was built, were reasonable and proper for ratemaking purposes under established Commission rules and regulations. ORA examined some of the recorded financial data that SCE used in connection with forecasting its proposed revenue requirement in this application. ORA's primary emphasis focused on determining whether costs that SCE recorded and reported are reasonably reliable and should be included for GRC forecasting purposes. ORA also reviewed SCE's external auditor's work to note if any control deficiencies exist to assess whether SCE's controls provide a reasonable level of assurance that the recording and compilation of historical data from SCE's records is adequate. ORA's review of expenses covers 2011-2015, while its review of Utility Plant covers 2013-2015.

Based on the examination procedures performed, ORA has no recommended adjustments to historical expenses for the following SCE exhibits:

- SCE-02, Transmission and Distribution
- SCE-03, Customer Service

[1213] Ex. SCE-9, Vol. 1, p. 58, lns. 8-9.

[1214] Ex. SCE-09, Vol. 1, p. 58, lns. 12-16.

[1215] Ex. ORA-22.

- SCE-04, Information Technology
- SCE-05, Power Supply
- SCE-06, Human Resources, and
- SCE-07, Operational Services.

Based on ORA's results of the Utility Plant review for 2013 to 2015, ORA proposes an audit adjustment to increase weighted average Customer Advances for Construction (CAC) and reduce weighted average Rate Base for 2015 by $2.267 million.[1216] Customer Advances for Construction (CAC) represent refundable amounts provided by customers in advance of constructing facilities. SCE requires a refundable advance when it extends utility services to new customers. Customer advances may be refunded in whole or in part in accordance with SCE's tariffs. SCE reduces its Rate Base by the average customer advances balance. SCE's weighted average recorded CAC for the base year 2015 totaled approximately $69.490 million.[1217] However, ORA discovered that this figure is incorrectly stated as $67.223 million in SCE's calculation of Rate Base,[1218] a difference of $2.267 million. Since Rate Base is reduced by the average customer advances balance, this $2.267 million error results in a $2.267 million overstatement of SCE's weighted average Rate Base for 2015 in the Results of Operations (RO) Model. Therefore, for 2015, ORA proposes an audit adjustment to the RO Model to increase weighted average CAC and to reduce weighted average Rate Base by $2.267 million. SCE incorporated ORA's adjustment in errata.[1219]

Regarding Balancing and Memorandum Accounts[1220], SCE presents ratemaking proposals for recovering its CPUC-jurisdictional base-related revenue requirement beginning in 2018, including proposals associated with 17 balancing and memorandum accounts and regulatory mechanisms, of which two (2) accounts are yet to be established and five (5) accounts are already reviewed annually by ORA in the Energy Resource Recovery Account (ERRA) compliance proceeding.

[1216] Ex. ORA-22, p. 2.

[1217] Ex. SCE-09, Vol. 2A, p. 45, Table IV-14.

[1218] Ex. SCE-09, Vol. 2A, p. 42, Table IV-13.

[1219] Ex. SCE-09, Vol. 2A.

[1220] Ex. ORA-22, pp. 23-27.

ORA reviews the recorded operation of the Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA) in SCE's annual ERRA proceedings. The PLDPBA is a two-way balancing account that records the difference between: (1) recorded capital-related revenue requirements for the Pole Loading Program and the Deteriorated Pole Program, (2) Operation and Maintenance expenses for the Pole Loading Program, and (3) the authorized Pole Programs revenue requirement as adopted in D.15-11-021.[1221] ORA will examine the cumulative recorded activity in the PLDPBA on the number of repairs and the number of poles replaced in SCE's next GRC, currently scheduled for a 2021 test year.[1222] When SCE files its next GRC application, at least three years of data will be available for ORA's review and analysis. ORA performed an examination of the recorded expenses found in the following 10 accounts and proposes no accounting adjustments:

- RRIMA (Residential Rate Implementation Memorandum Account, Oct 2015-June 2016)
- RIIM (Reliability Investment Incentive Mechanism) and successor account SRIIM (Safety and Reliability Investment Incentive Mechanism)
- Bark Beetle CEMA (Catastrophic Event Memorandum Account) (2012-2014)
- PDDMA (Project Development Division Memorandum Account)
- MCAGCCMA (Marine Corps Air Ground Combat Center Memorandum Account, Oct 2014 – Jun 2016)
- SOBA (Edison Smart Connect Opt-Out Balancing Account, Apr 2012 – Jun 2016)
- RSDMA (Residential Service Disconnection Memorandum Account, Jan 2015 – Jun 2016)

[1221] Ex. SCE-09, Vol. 1, pp. 30 and 31. The recorded operation of the PLDPBA is reviewed by the Commission in SCE's annual ERRA Review proceeding. Additionally, the cumulative recorded activity in the PLDPBA is to be reviewed in SCE's 2018 GRC and is to include: (1) the cumulative spending in the PLDPBA relative to authorized amounts, and (2) information on the number of repairs and the number of poles replaced.

[1222] Ex. SCE-09, Vol. 1, p. 32. SCE states it will provide the 2016 recorded operation of the PLDPBA, including the information on the number of repairs and the number of poles replaced in 2016 once these amounts are known through supplemental testimony in this GRC. SCE states that the 2017 operation of the PLDPBA will not be available until 2018 and Commission review [of 2017] can be performed in SCE's 2018 ERRA Review proceeding and the cumulative recorded activity in the PLDPBA can be examined in SCE's 2021 GRC.

- EDRPMA (Energy Data Request Program Memorandum Account, Dec 2014 - Jun 2016) and
- CDAP (Customer Data Access Project costs), also known as ESPI (Energy Service Provider Interface costs)
- TAMA Distribution (Tax Accounting Memorandum Account, 2015) and TAMA Generation (Tax Accounting Memorandum Account, 2015)

ORA found no required accounting adjustments. ORA found that the accounting entries to the foregoing 10 accounts for the periods indicated are appropriate, correctly stated and in compliance with applicable Commission decisions. ORA does not object to SCE's proposals regarding the 10 balancing and memorandum accounts and regulatory mechanisms for modifying, recovering, eliminating and continuing accounts.

22. COMPLIANCE

ORA has no comments on this issue at this time.

23. CEMA BARK BEETLE RECOVERY

SCE requested that the Commission find that the $10.5 million in O&M expenses recorded in SCE's Bark Beetle CEMA for 2012-2014 are reasonable, and authorize the transfer of the December 31, 2014 balance in the Bark Beetle CEMA O&M Cost Sub-account, plus interest, to the Base Revenue Requirement Balancing Account (BRRBA) for recovery in rates.[1223] ORA reviewed SCE's Bark Beetle CEMA, and does not oppose SCE's request for rate recovery.[1224]

24. CALSLA ISSUES

ORA has no comments on this issue at this time.

25. OTHER ISSUES

25.1 Results of Operations

SCE filed its TY 2018 GRC application on September 1, 2016, and provided ORA with an accompanying RO model on September 13, 2016. SCE updated the RO model on February 24, 2017 to accommodate user functionality and increase run-time efficiency.[1225]

[1223] Ex. SCE-12, p. 1.

[1224] Ex. ORA-22, pp. 24 and 27.

[1225] SCE RO model update letter dated February 24, 2017.

ORA performed limited testing of the RO model and determined that it reflected a reasonable calculation of the Summary of Earnings.

ORA used the updated RO model to calculate the Summary of Earnings depicted in ORA's testimony dated April 7, 2017.[1226]

The various ORA witnesses provided input data for the RO model. Discussions and analyses of the input data are contained in the corresponding ORA exhibits. ORA made some minor modifications to SCE's February 24, 2017 version of the RO model and some manual inputs to accommodate some witnesses' requests, so that the RO could reflect these recommendations.

ORA and SCE agree that SCE is authorized a rate of return (ROR) of 7.90 percent.[1227] However, while ORA's testimony shows a 7.90% ROR for ORA's revenue requirement, SCE shows a 7.86% ROR. The difference in ROR is due to the different methods used by ORA and SCE related to the proposed policy for calculating customer deposits.[1228] This is discussed in Exhibit (Ex.) ORA-20.

ORA's April 7, 2017 testimony includes tables showing ORA's and SCE's Summary of Earnings at proposed rates for the total company, allocated between FERC and CPUC. The tables also reflect a Rate Base Adjustment, which is a rate base offset that was adopted in SCE's previous GRC decision D.15-11-021.[1229] As discussed in that decision, "…the offset is implemented as a direct line item adjustment to rate base, independent of other factors. The rate base offset in turn impacts other revenue-dependent portions of the model (e.g., taxes, franchise requirements). The value of the offset is amortized (on a straight line basis) over the course of 27 years (2016 to 2042)."[1230]

The Rate Base Adjustment, combined with the FERC and CPUC allocation, add-up to the total company amounts.

[1226] Ex. ORA-2, p. 2.

[1227] Ex. SCE-09, Vol. 1, p. 8, fn. 8, "SCE's currently effective rate of return was authorized by the Commission in D.12-12-034."

[1228] Ex. ORA-2, p. 2 and Ex. ORA-20.

[1229] D.15-11-021, p. 431, "…we adopt a simple rate base offset to offset the future tax expense related to the change in accounting for repair deductions."

[1230] D.15-11-021, p. 455.

25.2 Income Tax Expense

Income tax is a function of current federal and state tax law, including new laws expected to affect the test year, regulatory tax policy as determined numerous Commission decisions, and ORA's recommended tax policy. Much of existing Commission tax policy was established in Order Instituting Investigation 24 (OII 24), Decision D.84-05-036.[1231] Numerous subsequent decisions adopted a variety of changes in ratemaking tax policy in order to comply with changes in federal and state tax laws. Consequently, although a mathematical model may be used, there are a number of estimated factors driving income tax expense requiring a review to attempt to assess the reasonableness of the utility's request.

For Federal Income Tax (FIT) purposes, SCE used the corporate tax rate of 35%. For state income tax purposes, SCE used the corporate tax rate of 8.84% to compute California Corporate Franchise Taxes (CCFT).

Additionally, SCE proposes to extend the Tax Accounting Memorandum Account (TAMA) that was authorized in SCE's 2015 GRC decision. SCE states that the proposed extension will continue to mitigate any tax-related ratemaking implications resulting from estimating differences between forecast and incurred repair deductions, changes in tax law and guidance associated with tax depreciation, and the impact of any tax accounting method changes.[1232]

ORA reviewed SCE's testimony, workpapers and discovery responses and does not oppose the methodologies used by SCE to calculate estimated income tax expenses.[1233] ORA does not oppose SCE's proposal to extend the TAMA to years 2018 to 2020.

Regarding payroll and property taxes, ORA does not recommend adjustments as a result of its review of payroll and property tax rates for TY 2018.[1234] ORA's payroll and property tax recommendations reflect the results of ORA's Results of Operations (RO) model outputs.

[1231] 15 CPUC 2d 42 (1984).

[1232] Ex. SCE-09, Vol. 2, p. 20.

[1233] Ex. ORA-02, pp. 2 and 4-7. ORA's recommendation regarding accumulated deferred taxes appears in Ex. ORA-20P, Table 20-1, p. 4.

[1234] Ex. ORA-18, p. 1.

26. CONCLUSION

For all the foregoing reasons set forth above and in ORA's testimony. ORA asks that its recommendations be adopted.

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