Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001

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1. EXECUTIVE SUMMARY

The California Public Utilities Commission is in the process of advancing a new "risk-informed" process to support decision-making in the context of energy utility General Rate Cases (GRCs). The major goal is to improve safety performance of utility design, construction, operations & maintenance (O&M) by applying a transparent and understandable set of utility processes to identify and prioritize significant safety risks, to determine appropriate mitigation programs and projects to reduce or avoid those risks, and to translate those priorities, programs and projects into the GRC budget requests.

The development of this process has been taking place via a 2013 rulemaking proceeding and subsequent applications for Safety Model Assessment Proceedings (S-MAP). [1] This rulemaking, via Decision (D.) 14-12-025 established new mechanisms for developing risk-informed methodologies, incorporating them in GRCs, and requiring new accountability reporting to ensure that the utilities are meeting expectations for approved funding authorizations for safety programs and risk mitigations.

Even before the finalization of this new approach to ratemaking, however, California's major investor-owned utilities are required to incorporate elements of evolving risk assessment models and risk-informed mitigation into triennial GRCs and other rate cases.

The Risk Assessment and Safety Advisory Staff of the CPUC's Safety & Enforcement Division (SED) has the responsibility for supporting the S-MAP proceedings and for working with the Investor Owned Utilities (IOUs) to help implement appropriate policies and approaches to accomplish this. As part of that responsibility, SED has prepared this report on Risk and Safety aspects of Southern California Edison's (SCE) General Rate Case application for 2018-2020. The GRC Scoping Memo indicated that "SED's report will help the Commission identify whether and how SCE is complying with the guidelines for risk management that were provided in D.14-12-025 and are currently being further developed in the S-MAP proceeding." [2]

[1] Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities; R. 13-11-006.

[2] Scoping Memo for SCE TY2018 GRC CPUC Application A.16-09-001, December 12, 2016, pgs. 8-9: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M156/K128/156128660.PDF

This report provides a description of risk and safety in SCE's GRC testimony and analyzes how SCE's current risk assessment and management process is evolving and SCE is using it to:

- identify major risks;
- determine potential mitigation plans and programs; and
- inform SCE's GRC budget requests in order to reduce or avoid those major risks.

Because this is an evolving program, this report is more concerned with understanding SCE's approach, providing illustrative examples of major safety and risk issues in the utility's testimony and critiquing how well the utility has applied its methodology to the task of identifying, prioritizing and mitigating its operational safety risks.

SED Staff is engaged in a parallel process in the S-MAP to apply a critical evaluation of the utilities' risk models and to provide guidance for greater consistency among them, as well as working through the practical logistics of making risk assessment a more effective tool for regulatory oversight of utility operations and expenditures.[3]

Staff recognizes that in this Application, SCE employs new and evolving methods to assess risk. Though far from an exhaustive analysis of every aspect of SCE's risk assessment and safety mitigation proposals, this report will attempt to describe in understandable terms how the utility has described its process to assess and prioritize its major risks, and recommend how this might be improved in future GRCs.

In addition, Staff has compiled current data and statistics related to recent incidents reported by the utility, citations imposed by the Commission for violations of rules and general orders, and audits of operations conducted by CPUC enforcement staff. This represents a new element of GRC evaluation, as called for by recent legislation.[4] It is still unclear whether this information will have direct relevance in the Commission's eventual decisions on utility rate requests, but – much like the entire Risk Assessment program in its still nascent state – it provides a platform for the Commission and the utility to build upon in future GRCs.

[3] In A.15-05-002, et al., SED Staff provided an analysis of the four major utilities' risk models, as presented in their May 2015 applications and refined via a series of workshops and working groups. The Commission continues with the development of modelling approaches in Phase 2 of the proceedings, still ongoing.
[4] PU Code Section 750, added by statute 2014, Ch. 552, Sec. 2 (SB 900, Hill).

1.1 Observations and Conclusions

SED Staff analyzed and evaluated the risk-informed decision framework used by SCE to identify major risks and determine potential mitigation plans and programs, and concluded that these methods and processes have not been particularly well described or effectively used to inform the 2018 GRC Test Year budget request.

SCE admitted in testimony that it did not use risk assessment in the identification of its top risks, or to select programs to address those risks, but mostly after-the-fact as a way to measure risk reduction associated with the programs or projects proposed. Further, the funding allocation for risk mitigations was not based on risk analysis.

These two admissions, by themselves, have made it very difficult for SED to provide a positive evaluation of risk assessment in this GRC application. At this time, it would be unwise to accept SCE's risk assessment methods as a basis for determining reasonableness of safety-related program requests; indeed, we have found that SCE is classifying major categories of spending as safety related, even though they relate to issues of customer satisfaction or electric service reliability than safety. Additionally, much more could be done in the future to assist decision makers and intervenors in following the trail from risk assessment to budget request.

The current GRC, although partly subject to the new risk-informed decision-making approach, is essentially a transitional case. The traditional tools of intervenor testimony, evidentiary hearings and cross-examination of witnesses must still provide the Commission with a complete record for its decisions in this rate case.

Finally, as required by statute,[5] SCE bears the burden of proof to affirmatively establish the reasonableness of all aspects of its requests.

[5] PU Code Section 454.

1.2 MAJOR FINDINGS ON SCE'S RISK METHODOLOGY AND APPLICATION

- SCE's approach to risk-based decision-making is still evolving and most of the steps in the framework have yet to be implemented. In the current GRC, most of focus was on the first two steps of risk identification and risk evaluation.
- Currently, the majority of the risk analyses are conducted after a project or a program is identified, to measure the risk reduction associated with that project or program.
- SCE's GRC testimony does not contain what can be properly referred to as a risk register. A risk register based on risk event statements should contain, at a minimum, asset or activities, failure event statements, frequencies, impact dimensions, impact dimension scores, and other relevant information.
- SCE's approach to identify threats or risk drivers suffers from an almost non-existent level of granularity.
- Based on the presentation in the testimony, it is unclear whether risks were used to drive mitigation activities, or, rather, mitigation activities were looking for risks to mitigate.
- SCE's risk-spend efficiency metric is not mature enough to drive the 2018 GRC request at a program or project level.
- SCE's current risk-informed decision-making process is still too immature in this GRC cycle to allow meaningful analysis using the full Cycla 10-step process.
- Staff struggled to evaluate SCE's risks and risk assessment process in the initial stages of review. As a result, staff asked SCE to compile all of its risk testimony into a single volume. Even after receiving this compiled testimony, SED staff was still unable to see the bigger picture of SCE's risk assessment story. There were many individual parts, but we still could not determine how they contributed to the larger GRC. For example, SCE could not provide even a qualitative prioritization of its risks, and there were only two risk register items for which SCE used risk assessment to inform its current GRC request.
- SCE's definition of an outcome is what other utilities would typically define as a risk, and the outcome numbers in SCE's risk register show a very irregular distribution. The cause of this irregular distribution of outcomes appears to be due to the wide range of specificity levels in the risk definitions.
- SCE needs to align its risk scoring and risk register. SCE must have a clear idea of what it is scoring and why it is scoring it. It is unclear why SCE is scoring assets that are unrelated to risks that it has identified in its risk register, or why the risk register is missing scored asset risks.
- Some discussion about how risks changed between the 2015 GRC and current GRC would have been helpful, especially since it seems like SCE's risk register is incomplete. In the next GRC, SCE should include some explanation comparing its previous risk register to its then-current risk register.
- SCE did not use Current Residual Risk (CRR) scores to inform this GRC, but SCE has provided them for several assets.

- Assets that are less of a safety concern are still ranking very highly in terms of total CRR score due to high scores in the other components. We can only conclude that the total CRR score, and ultimately the ranking of assets based on total CRR score may have little to do with prioritizing safety based on SCE's current methodology.
- Risk spend efficiency has not been used by the utilities in the past, and much work remains to develop it fully. SCE is the first utility to provide the calculation in a filing, but it only used RSE results to elevate its priority for Underground Cable life extension funding.
- At this time, it would be unwise to accept SCE's risk-assessment methods as a basis for determining reasonableness of safety-related program requests. Indeed, we have found that SCE is classifying major categories of spending as safety related, even though they relate to issues of customer satisfaction or electric service reliability than safety. Additionally, much more could be done in the future to assist decision makers and intervenors in following the trail from risk assessment to budget request.

SED recommends that SCE develop, implement, and demonstrate a robust program for evaluating the effectiveness of its risk management program. This should include, as appropriate, identifying goals, objectives, criteria, and metrics. SCE should evaluate its risk management program, identify lessons learned and gaps, implement improvements, and then include this evaluation in its rate case application. This should include for example, performance of risk control measures, challenges, corrective actions, lessons learned, and opportunities for improvement.

The current GRC, although partly subject to the new risk-informed decision-making approach, is essentially a transitional case. The traditional tools of intervenor testimony, evidentiary hearings and cross-examination of witnesses must still provide the Commission with a complete record for its decisions in this rate case.

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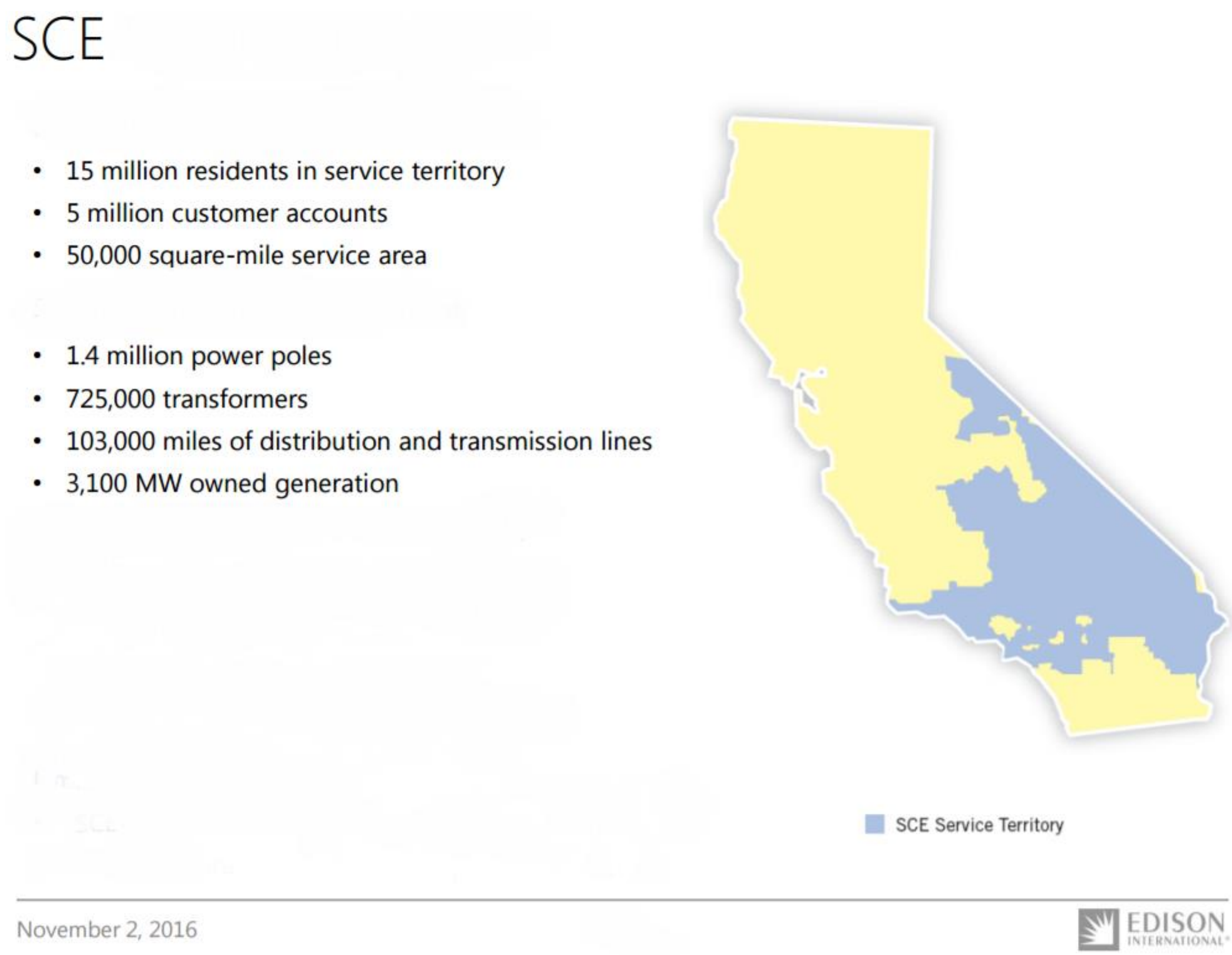
2 OVERVIEW

Figure 1 SCE Territory Map



Southern California Edison has approximately 12,000 employees.[6] The company provides electric service to 15 million people throughout a 50,000-square-mile service area within Central and Southern California.[7]

[6] Employees (2015): SED Data Request Response: SED-SCE-002-DR1610007-01 Q.02 Att.xls http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/D44C8A397930C0938825808E007E7674/$FILE/SCE-14%20Appendices.pdf (Page A-117)

[7] http://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-november-2016-business-update.pdf

3 SCE's Evolving Risk Management Program

3.1 Evaluation of SCE's Risk-Informed Decision Framework Using the Cycla 10-Steps Criteria

3.1.1 Regulatory Background on Requirement to Use Risk-Based Approach in GRCs

On November 14, 2013, the Commission opened Rulemaking (R.) 13-11-006, *Order Instituting* Rulemaking *to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan for Energy Utilities (the Risk OIR)*. The purpose of this rulemaking was to incorporate a risk-based decision-making framework into the Rate Case Plan (RCP) for the energy utilities' General Rate Cases (GRCs).[8] Such a framework and associated parameters would assist the utilities, interested parties, and the Commission, in evaluating how energy utilities assess their safety risk, and how they propose to manage, mitigate, and minimize such risks.

On December 9, 2014, the Commission issued D.14-12-025 in R.13-11-006 to modify the rate case plan to incorporate a risk-based decision-making framework into the GRCs for the large energy utilities, including SCE.[9] The current application represents the first SCE GRC to fall under the purview of D.14-12-025 and its requirement to use risk-based decision-making.

Furthermore, on August 18, 2016, the Commission in D.16-08-018 in the S-MAP proceeding (A.15-05-002, et al) adopted the 10-step criteria developed by Cycla Corporation in PG&E's Test Year 2014 GRC as the tool to be used for evaluating the maturity, robustness, and thoroughness of a utility's risk-based methodology in GRCs.[10]

3.1.2 Overview of SCE's Risk-Informed Decision-Making Approach

This section first provides a brief and very high-level description of some key features and components in SCE's risk-based approach as described its GRC testimony and will then apply the Cycla 10-step criteria to evaluate SCE's risk-based approach.

[8] In addition, this would apply to jurisdictional gas corporations' Gas Transmission and Storage (GT&S) rate cases.
[9] D.14-12-025, Ordering Paragraph 3.
[10] D.16-08-018, Ordering Paragraph 4.

SCE began to explicitly factor in risks in its decision-making in a more formal and quantitative manner starting in early 2014.[11] SCE refers to its risk-based approach as "Integrated Approach to Risk-Informed Decision-making." SCE's testimony describes the Risk-Informed Decision-making framework in terms of both the key elements comprising the framework and the main process steps in the execution of the framework.

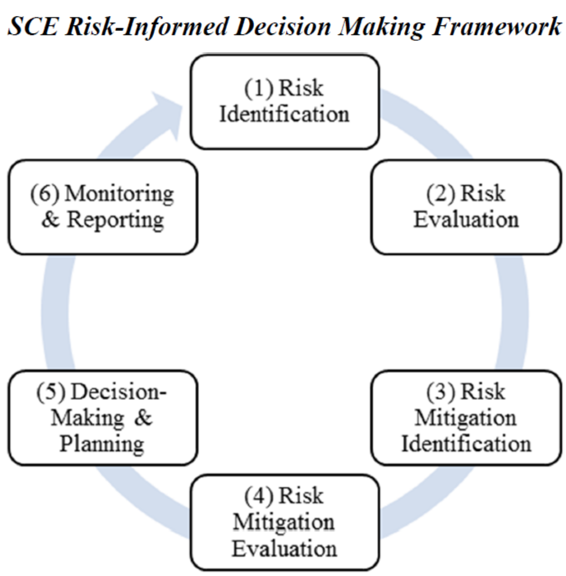
The five key elements in this Risk-Informed Decision-making[12] consist of:

1. Enterprise Risk Management (ERM)
2. Strategic Planning & Goal Setting
3. Financial Planning & Governance
4. Asset Management & Operational Risk Management
5. Business Resiliency

Traditionally, the term Enterprise Risk Management embodies the other four key elements listed in SCE's Risk-Informed Decision-making, but, for the purposes of this evaluation, we will treat them as separate elements consistent with the approach taken by SCE.

Viewed as a process, SCE's Risk-Informed Decision-making framework comprises the following six steps:[13]

Figure 2 SCE Risk-Informed Decision Framework



[11] SCE-01, p.31.
[12] Detailed descriptions of each of the elements are found in SCE-01, pp. 28-31.
[13] SCE-08, Vol. 03, p.50.

SCE has mapped the six steps in its Risk-Informed Decision-making framework to corresponding steps in the Cycla 10-step process as shown in the table below:

Table 1 SCE Framework Compared to Cycla

SCE's Risk-Informed Decision-Making Framework	Cycla Evaluation Model
1) Risk Identification & 2) Risk Evaluation	1) Identify Threats
	2) Characterize Sources of Risk
3) Mitigation Identification	3) Identify Candidate Risk Control Measures (RCMs)
4) Mitigation Evaluation	4) Evaluate the Anticipated Risk Reduction for Identified RCMs
	5) Determine Resource Requirements for Identified RCMs
5) Decision-Making & Planning	6) Select RCMs Considering Resource Requirements and Anticipated Risk Reduction
	7) Determine Total Resource Requirements for Selected RCMs
	8) Adjust the Set of RCMs to be Presented in GRC Considering Resource Constraints
	9) Adjust RCMs for Implementation following CPUC Decision on Allowed Resources
6) Monitoring & Reporting	10) Monitor the Effectiveness of RCMs

In the S-MAP proceeding, SCE referred to the Decision-Making & Planning in Step 5 as the Risk-Informed Planning Approach (RIPA). SCE is developing RIPA to manage its enterprise level risks. The objective of RIPA is to explicitly incorporate knowledge about risks into planning decisions.

RIPA uses input from risk scores and risk-spend efficiency (RSE) scores to inform decisions to prioritize mitigation programs and projects. Since RIPA is an enterprise-wide tool, its use requires calibration across the whole enterprise to ensure common understanding and evaluation of different risks. SCE is piloting the RIPA process in the Transmission and Distribution (T&D) operating unit in this GRC cycle and refers to this pilot in T&D as Prioritized Risk Informed Strategic Management (PRISM).[14]

[14] PRISM is described in detail in SCE-02, Vol. 1.

3.1.3 SCE's Risk Model and Decision Framework

According to information provided by SCE in the S-MAP proceeding, SCE's ERM framework was derived primarily from the International Organization for Standardization (ISO) 31000 and, to a lesser extent, the Committee of Sponsoring Organizations of the Treadway Commission (COSO): 2004 Enterprise Risk Management. SCE's ERM program "provides a Company-wide structure to identify, evaluate, mitigate, and monitor risks and to report them to the company's senior leadership…"[15]

As SCE only began to develop its risk model and risk calculation framework beginning in 2014, SCE's approach to risk-based decision-making is still evolving and most steps in the framework have yet to be implemented. In the current GRC, the focus was on the first two steps of risk identification and risk evaluation. SCE indicated that more effort will be placed on the risk mitigation steps in the future.[16]

SCE's testimony further reveals that broadly speaking "…the funding allocation to a risk mitigation program or project was not based on results of risk analysis…"[17] In fact, the GRC testimony states , "Currently, the majority of the risk analyses are conducted after a project or a program is identified, to measure the risk reduction associated with that project or program."[18] In some specific instances in this GRC, SCE began to prioritize spending within programs (or assets within an asset class), but not to prioritize whole programs or projects. This intra-asset prioritization was found in the risk analysis on overhead conductors (Overhead Conductor Program), poles, underground structures, and underground cables, where risk analysis provided information into the risk tradeoffs of different mitigation decisions.[19]

SCE's risk model defines two groups of risks: asset-related risks and utility-wide, non-asset-related, operational risks. Asset-related risks are those that arise from physical assets and activities associated with the operation of the assets. Utility-wide operational risks arise from risks not associated with a particular asset, and include such risks as financial, economic risks, business model risks, legal and regulatory risks, compliance risks, and human resource risks.

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[15] SCE-08, Vol. 3, p.45.
[16] SCE-08, Vol. 3, p.60.
[17] SCE-02, Vol. 1, p.25.
[18] SCE-08, Vol. 3, p.60.
[19] SEC-02, Vol 1, p.27, pp. 44-46.

SCE's risk identification approach revolves around the listing of risk statements. A risk statement identifies a risk event (e.g., a pole failure), an outcome (e.g., a wildfire), and the impact of the outcome (e.g., safety). As part of its T&D analysis in this GRC, SCE provided two tables mapping the capital and O&M activities to failure events, potential outcomes, and impact dimensions in the testimony in the SCE-01 workpapers.[20] Although these extensive tables can loosely be described as a risk register, they lack essential information that one would expect to find in a properly constructed risk register. A risk register based on risk event statements should contain, at a minimum, asset or activities, failure event statements, frequencies, impact dimensions, impact dimension scores, and other relevant information to enable numerical evaluation of the risks.

SCE uses a "Bowtie diagram" to map the progression of multiple risk drivers to eventual multiple impacts.

Figure 3 SCE Risk Bow-Tie Diagram

Bowtie Diagram

[21]

Since there could be multiple outcomes for a risk event, SCE calculates a risk score across five impact dimensions (safety, reliability, environmental, compliance, financial) for each outcome without applying any weights across the impact dimensions. The total risk score for the risk event is calculated as the simple, non-weighted sum for all the different outcomes resulting

[20] Tables of mapped T&D activities are found after p.46 in SCE-01, Workpapers.
[21] This symbolic bowtie diagram was presented by SCE in the S-MAP proceeding. A bowtie diagram with concrete examples of drivers and impacts is presented in SCE-08, Vol. 03, p.54 of the GRC testimony.

from that failure event. Since the risk contribution from all five impact dimensions is summed without applying weights, each of the five impact dimensions is effectively given equal weight.

SCE refers to its risk calculation formula as a Risk Evaluation Tool (RET). SCE's RET formula for each impact dimension and each scenario is:

$$Risk\ Score\ =\ TEF * CP * 10^{CI}$$

TEF is the trigger event frequency. TEF is the annual frequency of failure events described by the risk statement.

CP is the consequence percentage. It is defined as the percentage of trigger events that result in an adverse outcome across any of the five impact dimensions. CI is an integer logarithm-scale impact score across any of the five impact dimensions.

In the risk-informed decision framework pilot, PRISM, SCE uses a "Worst Reasonable Direct Impact (WRDI) assumption that selects the highest scoring combination of Consequence Percentage and Consequence Impact for each Risk Statement."[22]

The total risk score for an asset (or operation) is the sum of all scenario risk scores for that asset or operation.[23] SCE's RET formula is equivalent to the traditional risk formula (risk = f x C), where f is the frequency and C is the consequence.

To derive the Current Residual Risk (CRR) score, utility subject matter experts (SMEs) figure the various scenarios in which an asset can fail and cause injury/damage, etc. Each scenario is expressed as a risk statement. Each statement is examined to determine what impact dimension (safety, reliability, financial, etc.) the scenario could impact. Then trigger event frequency, consequence percentage, and whole-integer logarithmic impact score are estimated for each statement to produce a CRR sub-score for that risk statement. The impact dimensions are not weighted to produce each sub-score, meaning that Safety is given the same weight as other risk attributes. The simple sum of all sub-scores is the total CRR.

This example, drawn from SCE's testimony in the 2015 S-MAP application, illustrates how a score is compiled for a single risk:

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[22] SCE-02, Vol. 1, Appendix, p.4.

[23] A detailed analysis of SCE's RET formula can be found in the SED Staff Evaluation Report in the S-MAP proceeding http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K671/159671144.PDF

Table 2 Risk Scoring Example by Outcome

RISK SCORING FOR POLE FAILING IN SERVICE BY POTENTIAL OUTCOME IN 2015							
Risk Statement				**Current Residual**			
	No.	**Outcome**	**Impact Dimension**	**TEF**	**WRDI CP**	**WRDI CI**	**Risk Score**
a	1	Injury	Safety	230	0.012%	6	28,497
b			Financial	230	0.012%	4	285
c			Environmental	230	0.063%	5	14,375
d	2	Wildfire	Safety	230	0.031%	6	71,875
e			Financial	230	0.063%	6	143,750
f	3	Property Damage	Financial	230	0.012%	3	28
g	4	Outage	Reliability	230	24.014%	3	55,231
			Total				314,042

Table 3 Risk Scoring Example by Impacts Dimensions

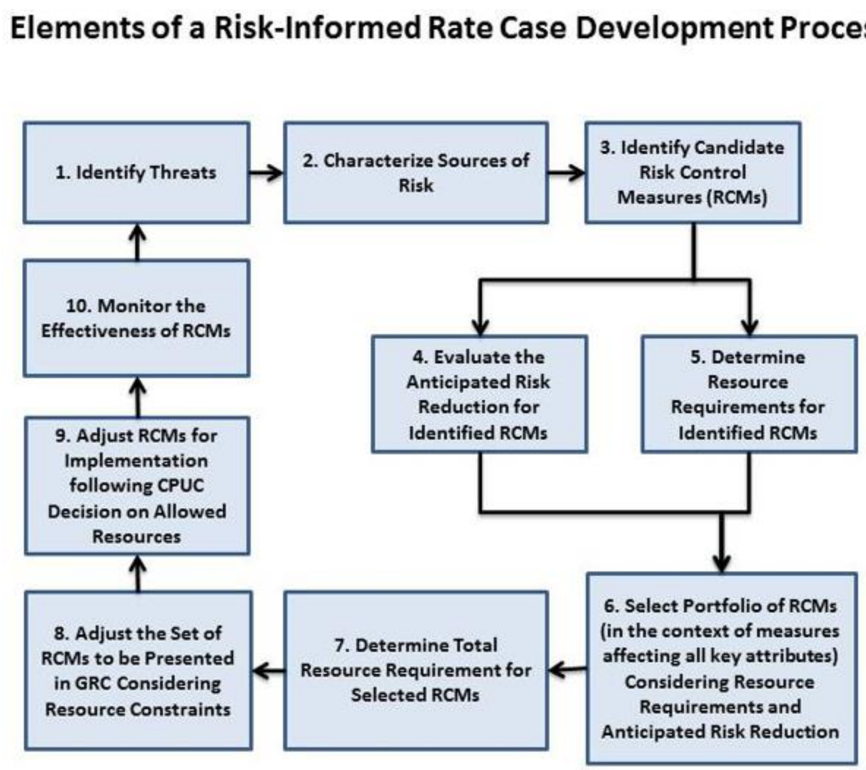
SUMMARY OF RISK SCORES FOR POLE FAILING IN SERVICE BY IMPACT DIMENSION		
	Impact Dimension	**Currrent Residual Risk Score**
a+d	Safety	100,372
g	Reliability	55,231
c	Environmental	14,375
b+e+f	Financial	144,063
	Compliance	0
	Total	314,042

Note: This risk example is not described in the current GRC. Please see Table 9 in Section 4.1.5 below for the assets for which SCE has applied a CRR in this GRC.

3.1.4 EVALUATION OF RISK MANAGEMENT PROCESS USING CYCLA 10-STEPS CRITERIA

This evaluation is based on a set of 10 steps developed by Cycla Corporation, which we represent graphically, below:

Figure 4 Elements of Cycla 10-Step Process



The Cycla 10-Step Process is as follows:

1. Identify the threats having the potential to lead to safety risk;
2. Characterize the sources of risk;
3. Characterize the candidate measures for controlling risk;
4. Characterize the effectiveness of the candidate risk control measures (RCMs);
5. Prepare initial estimates of the resources required to implement and maintain candidate RCMs;
6. Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs);
7. Determine the total resource requirements for selected RCMs;
8. Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work;
9. Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan;
10. Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again.

The Cycla 10-step process is used to evaluate the maturity, robustness, and thoroughness of the risk-informed resource allocation process in SCE's GRC application. As applicable, we apply a series of four grading levels to evaluate the filing.

Maturity Levels

1. Fully satisfies evaluation criteria
2. Substantially satisfies the evaluation criteria and provides a good foundation for future satisfaction of the criteria
3. Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria
4. Fails to satisfy the evaluation criteria
5. Too incomplete or too immature for evaluation using the Cycla 10-step criteria.

SED staff noted in the evaluation of SCE's Test Year 2015 GRC that "SCE did not design its GRC Application using a risk based approach."[24] Now, three years forward in the current Test Year 2018 GRC cycle, SCE has clearly made visible progress with the various test pilots to bring an explicit risk-based approach to reality. We are generally encouraged by SCE's incipient use of an explicit risk-based approach in GRCs as demonstrated in the various pilot programs, in particular, the PRISM pilot program in the T&D operating unit. At the same time, we expect to see substantially greater progress in the next GRC cycle.

This portion of the evaluation is focused almost exclusively on the T&D portion of the testimony, since it is in this operating unit where the most notable risk-based pilot programs, such as PRISM, are used.

1. **Identify the threats having the potential to lead to safety risk**

Evaluation result: 4 (Fails to satisfy criteria)

SCE's approach to identify threats (or, risk drivers, using the terminology adopted in the S-MAP proceeding) suffers from an almost non-existent level of granularity. For example, under the risk analysis for overhead conductors in SCE-02, Vol. 1, Appendix, there is little to no mention of risk drivers. Where risk drivers are mentioned at all, they are mentioned in the mitigation alternatives seemingly as an afterthought, rather than as drivers that lead to risk mitigation programs.

[24] *Safety and Enforcement Division Staff Report on Southern California Edison Company General Rate Case, 2015-2017, Application 13-11-003*, p.7.

This problem with non-granularity may have been rooted in SCE's risk identification methodology, which is based on failure event statements (for example: an overhead conductor comes down and results in various types of damage, outage, and/or injury/fatality). While it effective in conveying a fuller picture of what a risk entails, this approach to construct failure event statements tends to obscure the underlying root causes and risk drivers that led to a failure event.

For example, in SCE-02, Vol. 1, Appendix, p. 7, Table I-3 for risks associated with overhead conductors, three triggering events are listed. Obscured by these three high-level trigger events are what types of equipment failure or perhaps incorrect operation that might have caused the trigger events. An overhead conductor could have come down for a variety of causes, for example, a compression splice could have failed, or perhaps, a pin on an insulator at a cross-arm could have broken. Each of these granular risk drivers would have required a different and a more targeted mitigation strategy.

Instead, subsuming all granularity under the large heading of "overhead conductor down" due to whatever cause, would tend to result in the most drastic and the most expensive mitigation, which is to re-conductor the whole circuit, when perhaps a much more targeted and much cheaper mitigation strategy would have sufficed.

2. Characterize the sources of risk

Evaluation result: 3 (Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria)

Step 2 in the Cycla 10-step process is closely dependent on the quality of the threat identification in Step 1. Since Step 1 lays the foundation for all subsequent steps in the Cycla criteria, if Step 1 is deficient, then Step 2 will also suffer in rigor as a result. Just as in Step 1, the use of failure event statements as the foundation to estimate risks tends to reduce granularity in risk evaluation.

Several features in the PRISM approach are worth mentioning. First, the Worst Reasonable Direct Impact assumption can underestimate both the frequency and consequence/impact of very low frequency and very high consequence events, such as highly catastrophic wildfires. This is particularly true where SCE is relying on historical data as basis for estimating the frequency and consequence terms. In extreme cases, highly catastrophic events may not have occurred yet in the time range from which SCE is extracting the data. Secondly, the use of tranches to segregate risks is a sound approach. It can result in more accurate risk evaluation and more targeted mitigation.

This table from SCE testimony[25] shows the data sources for the various scoring areas in PRISM:

Table 4 SCE Data Sources by Scoring Area

Table I-1
Data Sources by Scoring Area

Data Source	Overhead Conductor	Poles	Underground Structures	Circuit Breakers	Transformers	Underground Cables	4 kV Circuits	Vegetation Management
Outage Database and Reliability Metrics System (ODRM)	x	x	x	x	x	x	x	x
CPUC Reportable Incident Reports	x	x	x	x	x	x	x	x
SAP Notifications on Inspection Results	x	x	x	x	x			
Operations Data (prioritization lists, integrated work plan, work orders, cost estimates, etc.)	x			x	x	x	x	
Preliminary Incident Reports (PIR) & EHSync			x	x			x	
Weibull Failure Curve Parameters				x	x	x		
Oversight & Quality Assurance (O&QA) Wire Down Records	x							x
Cal Fire	x							x
Asset Inventory (GE Smallworld, FIM Maps, etc.)	x					x		
Preliminary & Root Cause Reports				x	x			
Redbook Fault Duty	x							
SAP Emergency Pole Replacements		x						
Maintenance Records				x				

Subject Matter Experts (SMEs) played an important role in interpreting the data to estimate the trigger event frequencies (TEF), consequence percentages (CP), and consequence impacts (CI). In most cases, SMEs relied on the historical averages in the table above to estimate the TEF, CP, and CI values. There are several areas in which SCE went beyond using simple historical averages by constructing mathematical models. The most prominent deviation from using simple historical averages is found in the

[25] Table I-1 in SCE-02, Vol. 1, Appendix.

mathematical models used to estimate the TEF or failure rate as a function of time for wooden poles.[26] Another example is found in the underground structures, where mathematical models were used to evaluate TEF.

3. Identify candidate risk control measures (RCMs)

Evaluation result: 3 (Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria)

Based on the presentation in the testimony, it is unclear whether risks were used to drive mitigation activities, or, rather, mitigation activities were looking for risks to mitigate.[27] Pages 9 and 10 in SCE-02, Vol. 1, Appendix, where mitigation alternatives are identified, illustrates this "cart before the horse" thought process.

This observation is consistent with SCE's own characterization in SCE-01 that "SCE performed the detailed risk analyses in several areas after the project or programs scope was developed and the alternative selected. … In the future, SCE expects to perform such analyses before developing project scope and selecting from among alternatives; the analysis results will be a key input in the planning process."[28]

4. Identify the anticipated risk reduction for identified RCMs

Evaluation result: 3 (Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria)

For the most part SCE went to great lengths to describe the more prominent risk control programs but fell short in describing many of the alternatives. Some of the identified alternatives, for example, received a one or two-sentence cursory mention.

Risk reduction and Risk Spend Efficiency (RSE) were calculated for some of the RCMs and were presented in SCE-02, Vol. 1, Appendix. SCE acknowledges that the RSE metric is not mature enough to drive the 2018 GRC request at a program or project level.[29] With the exception of several programs, such as overhead conductor program,

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[26] SCE-02, Vol. 1, Appendix, pp. 17-18.
[27] SCE-02, Vol. 1, Appendix, pp. 9-10.
[28] SCE-01, p.36.
[29] SCE-02, Vol. 1, p.25.

poles, underground structure program, cable life extension program, the RSE was not used to drive decisions and funding requests in this GRC.

Steps 5 through 10:

Evaluation result: 5 (Incomplete or too immature for evaluation using the Cycla 10-step criteria)

3.1.5 Conclusion

Even though SCE has arguably made visible progress since the last GRC, SCE's current risk-informed decision-making process is still too immature in this GRC application to allow a meaningful analysis using all steps in the Cycla 10-step process. We will therefore conclude this evaluation by limiting it to only the first four Cycla steps. We expect SCE to make substantial progress in developing a risk-based decision-making framework in its next GRC application.

Table 5 Evaluation Results

1. Fully satisfies evaluation criteria
2. Substantially satisfies the evaluation criteria and provides a good foundation for future satisfaction of the criteria
3. Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria
4. Fails to satisfy the evaluation criteria
5. Too incomplete or too immature for evaluation using the Cycla 10-step criteria.

1. Identify the threats having the potential to lead to safety risk	**4**
2. Characterize the sources of risk	**3**
3. Characterize the candidate measures for controlling risk	**3**
4. Characterize the effectiveness of the candidate risk control measures (RCMs)	**3**
5. Prepare initial estimates of the resources required to implement and maintain candidate RCMs	**5**
6. Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs)	**5**
7. Determine the total resource requirements for selected RCMs	**5**
8. Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work	**5**
9. Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan	**5**
10. Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again	**5**

4 EVALUATION OF SCE'S GRC RISKS

SED staff set out to evaluate SCE's top risks and to better understand SCE's risk assessment process and how it informed SCE's GRC request. SCE served risk related testimony in several different sections, and staff struggled to evaluate SCE's risks and risk assessment process in the initial stages of review. As a result, staff asked SCE to compile all of its risk testimony into a single volume. SCE quickly and readily complied with this request.

Even after receiving this compiled testimony, SED staff still struggled to see the bigger picture of SCE's risk assessment story. There were many individual parts, but staff still could not determine how they contributed to the larger GRC. Ultimately, SED staff submitted several more data requests to try to determine how the GRC was informed by risk assessment.

At the request of the assigned Administrative Law Judges, SCE served the compiled risk testimony and SED data request on parties on December 19, 2016.[30]

4.1.1 SCE'S TWENTY SAFETY RISKS

As SED Staff pointed out in Section 5.1.3 above, SCE's testimony[31] contains what SCE identifies as a risk register, which includes its safety risks.

SED staff asked in a data request for SCE to provide a qualitative description of its top 10-15 safety risks, and if possible, to identify mitigation programs and the associated funding requested in its application related to those safety risks. SCE responded that the risk register provided in its testimony included twenty safety risks, and that SCE had not yet ranked-ordered those safety risks, nor mapped its GRC request to those risks.

To summarize, SCE was unable to take its twenty safety risks down to a list of top ten or fifteen safety risks. This leaves the Commission and parties with very limited information to work with, but SED Staff analyzed the information given, to the extent possible.

Table 6 below shows SCE's twenty safety risks, along with the outcomes provided by the utility. They are not prioritized by CRR or amount of funding requested.

[30] SCE Supplemental Testimony SCE-14 & Appendices
[31] WPSCE08V03BkB, pp. 127-137

Table 6 SCE's 20 Safety Risks

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
Critical aging customer service platform and technology obsolescence could result in customer service system failures, and lead to delays and errors in handling routine customer requests, problems in outage management, additional operational costs, non-compliance, regulatory scrutiny, delays in collecting revenue, and potential impact to critical care customers.	Operational or Business Disruption Customer Dissatisfaction	CS Re-Platform	1,510,180
Aging infrastructure could lead to pole failures resulting in serious injuries and/or outages, wildfire, financial awards to injured parties, and non-compliance.	Public Injury/Fatality Wildfire	Distribution & Subtransmission Wood Poles	1,097,224
Down wires, asset failures, copper thefts, or employee error could lead to worker or public contact with energized equipment, resulting in serious injuries and/or fatalities to workers and/or public, outages and negative public relations.	Public Injury/Fatality Worker Injury/Fatality	Distribution Overhead Conductor	3,513,916
High-hazard dams being subjected to major natural hazards, or failures could potentially cause an Uncontrolled Rapid Release of Water (URRW) leading to serious injuries and/or fatalities, destruction of property, long-term	Public Injury/Fatality	Hydro Dam Safety	257,600

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
environmental damage, compliance failures, loss of operation and revenue, and destruction of the project.			
Deliberate attack to SCE infrastructure could lead to serious damage or destruction to the grid, resulting in the loss of the grid for an extended period of time, and catastrophic outcomes at individual and community levels.	Public Injury/Fatality Worker Injury/Fatality Outage Cybersecurity	NERC CIP-014	742,007
Deliberate attack to SCE critical infrastructure could result in a security breach and potentially lead to damage of equipment (resulting in toxic spills), cascading outages, system failures, and serious injuries and/or fatality to workers.	Worker Injury/Fatality Outage Operational or Business Disruption	NERC CIP-014	742,007
Asset, system, process or worker failure, and security breach could cause SCE's Advanced Metering Systems to fail. The outcomes of these types of failures may impact public and employee safety, cause loss or delay of corporate revenue, and trigger increased manual work arounds, loss of data, large-scale outages, damage to corporate reputation, and customer dissatisfaction.	Public Injury/Fatality Worker Injury/Fatality Outage Operational or Business Disruption	NERC CIP-014	742,007

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
Failure of equipment exposes workers or members of the public to hazards. This could result in serious injuries and/or fatalities, financial awards to injured parties, non-compliance, outages and negative public relations.	Public Injury/Fatality Worker Injury/Fatality	Not scored	Not scored
Worker error, and/or process failures could expose the public or workers to potential hazards. This could result in serious injuries and/or fatalities, financial awards to injured parties, non-compliance, outages, and negative public relations.	Public Injury/Fatality Worker Injury/Fatality	Not scored	Not scored
Failure to implement an effective company-wide business resiliency planning and emergency management system in preparation for business disruptions could result in delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies; public or employee injuries or fatalities; and/or increased regulatory scrutiny.	Public Injury/Fatality Worker Injury/Fatality Outage Operational or Business Disruption	Not scored	Not scored
Failure to implement an effective company-wide business resiliency planning and emergency management system responding to outcomes from changing environmental conditions (e.g., increase wildfires risk	Public Injury/Fatality Worker Injury/Fatality Wildfire Outage	Not scored	Not scored

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
due to drought) could result in public or employee injuries or fatalities and/or increased impact from wildfires to SCE's assets.			
Failure to implement an effective company-wide business resiliency planning and emergency management system in responding to natural disasters could result prolonged system outage; delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies.	Public Injury/Fatality Worker Injury/Fatality Outage Operational or Business Disruption	Not scored	Not scored
Failure to implement an effective company-wide business resiliency planning and emergency management system in responding to man-made disasters could result in system failure; delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies.	Public Injury/Fatality Worker Injury/Fatality Outage Cybersecurity	Not scored	Not scored
Employees not following processes, or processes not accurately reflecting the operating needs could lead to poor/inappropriate records management resulting in inability to access information, poor asset	Public Injury/Fatality Worker Injury/Fatality Outage Operational or Business Disruption	Not scored	Not scored

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
management, and inability to respond fully, accurately and on time to regulatory inquiries and requests.			
Vendor/supplier performance (labor disputes, raw material shortage, etc.) could lead to disrupted supply chain and result in inability to complete work assigned to contract crews, and insufficient material to support O&M, capital, storm and emergency job activities.	Public Injury/Fatality Outage Operational or Business Disruption	Not scored	Not scored
Disruptive and unstable work environment during change initiatives could lead to decreased employee engagement, inability to retain/attract talent resulting in lower levels of performance, and decreased work safety practices, productivity and efficiency.	Worker Injury/Fatality	Not scored	Not scored
SCE fleet accident could expose public and/or workers to hazards. This could result in injury, financial awards to injured parties, non-compliance, and negative public relations.	Public Injury/Fatality Worker Injury/Fatality	Not scored	Not scored
Disgruntled employee(s) who are more susceptible to workplace violence could harm themselves or others, resulting in serious injuries and/or fatalities to workers, severely negative	Worker Injury/Fatality Operational or	Not scored	Not scored

Safety Risks	Outcomes	Scored Asset	1-Year Current Residual Risk Score
psychological effects on workers, and lawsuits.	Business Disruption		
Attempted copper theft leading to human contact with underground cable riser, resulting in serious injuries and/or fatalities.	Public Injury/Fatality	Not scored	Not scored
B-bank transformer in service failure leading to B-bank transformer unavailability and potentially resulting in safety incidents.	Public Injury/Fatality	Not scored	Not scored

Based on this table, we can see that Public/Injury Fatality (16 instances) and Worker Injury/Fatality (14 instances) are the most common outcomes for SCE's top risks. The next most common outcomes are an Outage and Operational or Business Disruption (9 instances each). After that, the outcome instances sharply drop off. Wildfire and Cybersecurity outcomes are driven by only two risks each. Customer Dissatisfaction occurs as an outcome once, and while this outcome is of concern, it is not directly related to safety.

SCE's definition of an outcome is what other utilities would typically define as a risk, and the outcome numbers in SCE's risk register show a very irregular distribution. The cause of this irregular distribution of outcomes appears to be due to the wide range of specificity levels in the risk definitions. Here is a comparison of a Public Injury/Fatality risk to a Wildfire risk:

- Attempted copper theft leading to human contact with underground cable riser, resulting in serious injuries and/or fatalities.
- Failure to implement an effective company-wide business resiliency planning and emergency management system responding to outcomes from changing environmental conditions (e.g., increase wildfires risk due to drought) could result in public or employee injuries or fatalities and/or increased impact from wildfires to SCE's assets.

These two risk descriptions take two very different approaches. The first one, which results in a Public Injury/Fatality outcome, is extremely specific. It is one type of event. The second risk takes an extremely broad approach to describing a risk. It seems to cover any sort of resiliency planning related to changing environmental conditions, which may or may not include wildfire. With such a broad description, it makes it hard to assess whether SCE has truly considered each of its risks, or at what depth and specificity it has considered these risks. SCE admits itself that its risk analysis capabilities are not at the same level of maturity across different operational areas, so this may be contributing to the different specificity levels.

In addition, it is unclear why SCE could not provide even a qualitative prioritization of its risks. Clearly, copper theft would not seem to be at the same level of risk as wildfire, as it is not nearly as catastrophic or pervasive. Why was SCE unable to present any differentiation or prioritization between these two outcomes? Although its capabilities at this point in time may be limited, SCE should have included qualitative prioritizations of risks to the extent possible.

One final note is that the copper theft risk actually appears twice in SCE's risk register. It also appears in the following risk: "Down wires, asset failures, copper thefts, or employee error could lead to worker or public contact with energized equipment, resulting in serious injuries and/or fatalities to workers and/or public, outages and negative public relations." This duplication leads us to believe that SCE did not spend much time reviewing or developing its risk register.

Recommendation

SCE should use risk descriptions that are consistent in specificity level. We also urge SCE to move quickly to establish a complete and comprehensive risk register for its operations. SCE may consider referring to PG&E's 2017 GRC filing as well as Sempra's recent RAMP filing for help developing a comprehensive list of risks.

4.1.2 Scored Risk Register Risks

Although SCE is still developing its risk assessment capabilities, it has provided asset risk scores in several areas of its GRC. We have attempted to map SCE's scored asset risks to its risk register risks in Table 6 above.

From the table, we see that five of SCE's scored assets correlate to seven of the risks in SCE's risk register. In total, SCE scored eight T&D assets and eight non-T&D assets in its GRC testimony. From our review of the testimony, SCE still has work to do when it comes to tying together its asset scoring and its risk register. These seem to be independent and unrelated exercises, when they should be inextricably linked.

As SCE's risk assessment capabilities advance, we expect to see a cohesive presentation of its risk register and its risk scoring.

Recommendation

SCE needs to align its risk scoring and risk register. SCE must have a clear idea of what it is scoring and why it is scoring it. It is unclear why SCE is scoring assets that are unrelated to risks that it has identified in its risk register, or why the risk register is missing scored asset risks.

4.1.3 Risk Informed GRC Requests and Safety Risks

In a data request, SED staff asked SCE to describe, at a high level, areas of its GRC that were informed or validated by risk assessment. [32] Based on that response, we have matched those areas to the twenty safety risks. However, there were only two instances where risk assessment was used to validate the GRC request for a safety risk identified in the risk register.

Table 7 Risks and GRC Requests

Safety Risks	GRC Request
Aging infrastructure could lead to pole failures resulting in serious injuries and/or outages, wildfire, financial awards to injured parties, and non-compliance.	Deteriorated Poles – Modified Remaining Section Modulus Thresholds.
Down wires, asset failures, copper thefts, or employee error could lead to worker or public contact with energized equipment, resulting in serious injuries and/or fatalities to workers and/or public, outages and negative public relations.	Overhead Conductor Program

[32] SED-SCE-001, Question 9.

The first instance was related to deteriorated poles, which relates to the aging infrastructure pole failure risk. SCE used risk assessment to examine the relative impact of changing Intrusive Pole Inspection (IPI) cycles and Remaining Section Modulus (RSM)) thresholds (a numerical measure of pole degradation), resulting in modified RSM thresholds.[33]

The second instance of risk informing a risk register risk GRC request relates to down wires asset failures, which could lead to worker or public contact with energized equipment. SCE's risk analysis in the Overhead Conductor Program (OCP) resulted in two decisions according to SCE, "scoping criteria for proactively replacing overhead conductor and the mix of mitigations under consideration to achieve OCP objectives."[34]

Recommendation

Although SCE self-identifies its risk assessment processes as immature, its risk register, as well as its GRC asks (informed by risk assessment) should all be aligned. There were only two risk register risks for which SCE used risk assessment to inform its current GRC request. This is not enough progress. SCE should greatly ramp up its risk assessment efforts.

4.1.4 Comparison of Risks in the Previous GRC

In its 2015 GRC, SCE filed supplemental testimony in response to an Assigned Commissioner's Amended Scoping Memo.[35] This directed SCE to "provide as direct of a linkage as possible between existing and new controls in the previous GRC testimony to specific safety and reliability risk that SCE faces in its operations." In its supplemental testimony, SCE identified ten risk statements, the potential impact of the risk event, the summary of projects proposed to mitigate the risks, risk drivers, specific existing and new control activities proposed, and alternatives SCE considered in order to mitigate or to respond to the risk event.

The ten risk statements as presented in SCE's supplemental testimony are as follows:

1. **"Conductor Failure Risk"** – Conductor failure leading to potential injury, property damage (including wildfire) or outage.
2. **"Pole Failure Risk"** – Power pole failure leading to potential injury, property damage or outage.

[33] See SCE-02, Volume 9, pp. 32-33 for more information.
[34] SCE-02, Volume 8, pp. 47-51 for more information.
[35] Amended Scoping Memo, SCE TY 2015 GRC A.15.11-003.

3. **“Underground Structure and Underground Equipment Failure Risk”** – Underground structures (vaults and manholes) failure leading to potential injury, property damage or outage.
4. **“Other Electrical Equipment Failure Risk” -** Equipment or system failure leading to potential injury, property damage (including wildfire) or outage.
5. **“Workforce Safety and Worker Capability”** – Worker safety, training, material, equipment and related expenses to mitigate worker safety incidents, including contract workers.
6. **“Physical and Cyber Security Risk”** – Insufficient security protection of grid assets, customers (including data privacy), employees and associated supervisory control systems, data storage and networks.
7. **“Emergency or Catastrophic Incident”** – Inability to survive, recover from, and manage the consequences of a significant, complex outage or incident.
8. **“Inadequate System Capability Risk”** – Insufficient system capability and configuration to accommodate customer demands for safe and reliable services.
9. **“Energy Supply Risk”** – Inadequate energy supply could result in supply shortages or market disruptions or other failures that would affect reliability or safety.
10. **“Information Systems Infrastructure Risk”** – Inadequate data or communication infrastructure that results in the loss of the ability to adequately respond to current or expected customer and business demands.

Table 8 shows that seven of the ten risks (or at least, substantially similar risks) identified in the previous GRC have carried over to the current GRC.

Table 8 Comparison of Current GRC Risks with TY2015 Risks

Current GRC Risk	Previous GRC Risk Statement
Down wires, asset failures, copper thefts, or employee error could lead to worker or public contact with energized equipment, resulting in serious injuries and/or fatalities to workers and/or public, outages and negative public relations.	#1 Conductor Failure Risk (previously included underground cable failure risk too)
Aging infrastructure could lead to pole failures resulting in serious injuries and/or outages, wildfire, financial awards to injured parties, and non-compliance.	#2 Pole Failure Risk
Failure of equipment exposes workers or members of the public to hazards. This could result in serious injuries and/or fatalities, financial awards to injured parties, non-compliance, outages and negative public relations.	#4 Other Electrical Equipment Failure Risk

Current GRC Risk	Previous GRC Risk Statement
B-bank transformer in service failure leading to B-bank transformer unavailability and potentially resulting in safety incidents.	#4 Other Electrical Equipment Failure Risk (previously included more than substation transformers)
Worker error, and/or process failures could expose the public or workers to potential hazards. This could result in serious injuries and/or fatalities, financial awards to injured parties, non-compliance, outages, and negative public relations.	#5 Workforce safety and Worker Capability
Employees not following processes, or processes not accurately reflecting the operating needs could lead to poor/inappropriate records management resulting in inability to access information, poor asset management, and inability to respond fully, accurately and on time to regulatory inquiries and requests.	#5 Workforce Safety and Worker Capability
Deliberate attack to SCE infrastructure could lead to serious damage or destruction to the grid, resulting in the loss of the grid for an extended period of time, and catastrophic outcomes at individual and community levels.	#6 Physical and Cyber Security Risk
Deliberate attack to SCE critical infrastructure could result in a security breach and potentially lead to damage of equipment (resulting in toxic spills), cascading outages, system failures, and serious injuries and/or fatality to workers.	#6 Physical and Cyber Security Risk
Failure to implement an effective company-wide business resiliency planning and emergency management system in preparation for business disruptions could result in delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies; public or employee injuries or fatalities; and/or increased regulatory scrutiny.	#7 Emergency or Catastrophic Incident

Current GRC Risk	Previous GRC Risk Statement
Failure to implement an effective company-wide business resiliency planning and emergency management system responding to outcomes from changing environmental conditions (e.g., increase wildfires risk due to drought) could result in public or employee injuries or fatalities and/or increased impact from wildfires to SCE's assets.	#7 Emergency or Catastrophic Incident
Failure to implement an effective company-wide business resiliency planning and emergency management system in responding to natural disasters could result prolonged system outage; delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies.	#7 Emergency or Catastrophic Incident
Failure to implement an effective company-wide business resiliency planning and emergency management system in responding to man-made disasters could result in system failure; delayed or uncoordinated company response and recovery efforts; failure to timely communicate and coordinate with external agencies.	#7 Emergency or Catastrophic Incident
Critical aging customer service platform and technology obsolescence could result in customer service system failures, and lead to delays and errors in handling routine customer requests, problems in outage management, additional operational costs, non-compliance, regulatory scrutiny, delays in collecting revenue, and potential impact to critical care customers.	#10 Information Systems Infrastructure Risk (previously included all IT infrastructure including customer service related systems).

SCE apparently has taken some of the risks identified in the previous GRC and broken them out into separate, more specific risks. For example, the Emergency or Catastrophic Incident risk has been broken out in four more-specific risks in this GRC.

SCE has identified nine new risks, such as records management, employee retention, and fleet accidents.

There are a few risks identified in the previous GRC that are not specifically called out in the current risk register: Underground Structure and Underground Equipment Failure Risk, Inadequate System Capability Risk, and Energy Supply Risk.

SCE did use risk assessment to inform its GRC request for both underground structures[36] and underground cables[37] and scored both these assets. As discussed before, some of the risk definitions are fairly broad, so it's hard to determine which elements of SCE's system might be captured in each risk.

Recommendation

The 2015 GRC risk statements were developed in response to an Assigned Commissioner's Amended Scoping memo and were not part of an SCE exercise to develop a risk register. Nonetheless, some discussion about how risks changed between the 2015 GRC and current GRC would have been helpful, especially since it seems like SCE's risk register is incomplete.

In the next GRC, SCE should include some explanation comparing its previous risk register to its current risk register, given that there were so few risks to begin with.

4.1.5 Scored Assets

Although CRR scores were not used to inform this GRC, SCE has provided them for several assets. As described by SCE, the scoring for the T&D assets is generally much more sophisticated than the non-T&D assets. SED staff expect these numbers to change as SCE refines and reviews its methodology, but staff analyzed these numbers nonetheless. On the following page, Staff provides a table of all of SCE's scored assets, the safety component of the CRR score, the mitigations for the asset, and the requested 2018 Test Year capital and O&M spending. Staff only included the 1-year CRR scores because multi-year CRR scores were not available for the non-T&D assets.

In Table 9 below, the top three risks based on the 1-year CRR scores, in order, are Distribution Overhead Conductor (3,513,916), the CS Re-Platform (1,510,180), and Distribution

[36] Risk analysis supported one mitigation measure over another.
[37] SCE added an activity supported by its risk spend efficiency calculation.

& Subtransmission Wood Poles (1,097,224). The first and last are T&D assets while the second is not.

The CRR score contains many components besides safety, so we if we just look at the safety component of the CRR score, the top three risks based on the safety component score are Distribution Overhead Conductor (3,025,833), Distribution & Subtransmission Wood Poles (509,892), and Hydro Dam Safety (230,000). The first two are T&D assets, which were also on the above 1-year CRR top three risks, and the third is not a T&D asset.

It should be noted that there is a large difference between the top CRR safety component risks (i.e. Distribution Overhead Conductor) compared to the Distribution & Subtransmission Wood Poles. Yet Distribution & Subtransmission Wood Poles is the #1 risk based on total funding requests of $391,551,000 for TY 2018. SCE has not adequately explained why this asset risk, which has a CRR safety component score of almost 6 times less than Distribution Overhead Conductor, should have such a large percentage of ratepayer funding.

When looking at just the safety component of the CRR, the CS Re-Platform actually drops down to the 14th rank out 16 scored assets. This means that this asset has little to do with safety, yet its total CRR score is quite high. This is due to an enormous value that SCE has determined for Customer Experience part of the CRR score.

Table 9 Safety Rated Assets, CRR Scores and Proposed TY2018 Mitigation Spending Requests

		1-yr Current Residual Risk (CRR)								
Asset	**Asset Type**	**Safety Component of CRR**	**Total CRR**	**Mitigation**	**2018 TY Capital Mitigation Spending ($000)**	**2018 TY O&M Mitigaton Spending ($000)**	**2018 TY Capital and O&M Spending Mitigaton Spending ($000)**	**Rank based on Safety Component of CRR**	**Rank based on Total CRR**	**Rank based on Total Spending (Larges to Smallest)**
Distribution Overhead Conductor	**T&D**	3,025,833	**3,513,916**	Reconductoring & Branch Line Fusing	$139,514	N/A	$139,514	**1**	**1**	**4**
CS Re-Platform[1]	**Non-T&D**	670	**1,510,180**	CS Re-Platform system and processes	$71,100	$18,490	$89,590	**14**	**2**	**5**
Distribution & Subtransmission Wood Poles	**T&D**	509,892	**1,097,224**	Replacement Repair (C Truss / Steel Stubbing) Repair (Guy)	$382,306 $3,771 N/A	N/A N/A $5,474	$391,551	**2**	**3**	**1**
Substation Circuit Breakers	**T&D**	21,584	**1,015,583**	Circuit Breaker Sub-IR Program	$47,994	N/A	$47,994	**11**	**4**	**9**
NERC CIP-014	**Non-T&D**	5,000	**742,007**	Deploy information technology, transmission and distribution, and physical security solutions to address the NERC CIP-014 standard.	$9,052	N/A	$9,052	**13**	**5**	**10**
Underground Cable	**T&D**	135,221	**517,020**	Worst Circuit Rehabilitation Cable Life Extension CIC Replacement	$126207 $23,991 $41,643	N/A	$191,841	**6**	**6**	**3**
4 kV Systems	**T&D**	157,976	**316,910**	4 kV Elimination	$215,219	N/A	$215,219	**5**	**7**	**2**
Hydro Dam Safety	**Non-T&D**	230,000	**257,600**	Increase safety of dams by improving the monitorin gof the dams and the dams' ability to withstand natural disasters.	$2,750	N/A	$2,750	**3**	**8**	**15**
Substation Transformers	**T&D**	81,663	**225,521**	Transformer Sub-IR Program	$68,601	N/A	$68,601	**7**	**9**	**7**
Service Center - Ridgecrest	**Non-T&D**	220,000	**222,420**	Improve the site and expand into the adjacent lot.	$104	N/A	$104	**4**	**10**	**16**
Vegetation Management	**T&D**	17,829	**104,564**	Palm Removal Compliance Trims Reliability Trims on Crestline, Estaban, Jasper, Kinneloa, or Moritz Circuit	N/A	$63,834	$63,834	**12**	**11**	**8**
Service Center - San Joaquin	**Non-T&D**	50,000	**52,870**	Renovate the existing site	$6,515	N/A	$6,515	**8**	**12**	**12**
Service Center - Santa Ana	**Non-T&D**	50,000	**52,201**	Renovate the existing site	$4,325	N/A	$4,325	**9**	**13**	**13**
Storage of Critical Electric Facilities	**Non-T&D**	22,000	**22,220**	Construction of an environmentally controlled and secured warehouse at the existing storage location.	$6,775	N/A	$6,775	**10**	**14**	**11**
Bishop Creek Intake 2	**Non-T&D**	58	**2,537**	Additional evaluations and seismic retrofits	$3,035	N/A	$3,035	**15**	**15**	**14**
Underground Structures	**T&D**	-	**84**	Conventional structure replacement Shoring Voltek	$72,730	N/A	$72,730	**16**	**16**	**6**

[1] CS Re-Platform total CRR includes derived CRR value for Customer Experience.

The NERC CIP-014 (Physical Security of Critical Infrastructure) rank based on the safety component of the CRR is only 13, but its rank based on the total CRR is 5. This is due to its extremely high reliability score component (not shown here). Substation circuit breakers show a similar pattern, scoring low in safety, but high in reliability. Interestingly, the Service Center – Ridgecrest asset's score is made up almost entirely of the safety component, so it ranks much more highly on safety than on the total CRR.

From these ranking comparisons, we can conclude that assets that are less of a safety concern are still ranking very highly in terms of total CRR score due to high scores in the other components. In this GRC, SCE did not use the CRR scores to inform its GRC request, and we cannot predict here how SCE would ultimately use CRR scores to inform future GRC asks. We can only conclude that the total CRR score, and ultimately the ranking of assets based on total CRR score may have little to do with prioritizing safety based on SCE's current methodology.

Recommendation

SCE should consider whether safety is being adequately prioritized in the results of any future risk scoring methodologies. In the future, it would be useful to compare the test year spending to past year spending.[38]

4.1.6 Risk Spend Efficiency

SCE is developing a quantity known as *Risk Spend Efficiency* (RSE) for each program, project, or different mitigation activity. RSE 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.

Risk spend efficiency has not been used by the utilities in the past, and much work remains to develop it fully. SCE is the first utility to provide the calculation in a rate case filing,[39] although the Sempra utilities recently provided a version of RSE for identified risk mitigations as part of their November 2016 Risk Assessment Mitigation Phase (RAMP) filing.[40]

RSE outcomes can be used to compare the cost effectiveness of mitigations for one particular risk, and eventually could be used to compare the cost effectiveness of mitigations across multiple risks.[41] SCE provided some illustrative risk spend efficiency calculations for both T&D and non-T&D assets. SCE used risk assessment to inform its GRC in only a handful of areas, but according to a response to an SED data request, SCE did use Risk Spend Efficiency in one particular case, Underground Cables. According to SCE, a second activity, cable rejuvenation was added to the Cable Life Extension program due to its high risk spend efficiency

[38] Energy Division will be issuing a report in the coming months, which should provide parties some better visibility into the spending patterns of these various areas.
[39] SCE-08, Volume 3, page 61.
[40] OII 16-10-015/016
[41] This is currently not possible because the utilities use relative risk rankings rather than absolute risk rankings, and some mitigations mitigate several risks, making it difficult to compare risk spend efficiency scores across different risks.

score. Cable rejuvenation provides life extension benefits by improving the insulation characteristics of aged cable.[42]

Recommendation

As described in SCE's testimony, SCE may use Risk Spend Efficiency to compare mitigations across risks in the future, and we encourage SCE to move in that direction.

4.1.7 Conclusion

Although SCE describes its progress toward using risk assessment in the future, it used risk assessment to inform this GRC in very few areas. The risks and risk scoring were seemingly unrelated, and the risk register itself seemed incomplete and inconsistent. The Safety Model Assessment Proceeding is aimed at the prioritization of risk and spending. SCE's GRC does not show any systematic or quantitative way of prioritizing spending. It is unclear how the Commission and intervenors will be able to review the safety aspects of SCE's GRC in the informed way visualized by the Commission in D.14-12-025. Although SCE may be making progress in the future, the Commission must review this GRC now, without the benefit of a comprehensive risk assessment from SCE.

[42] This is discussed in SCE-02, Volume 8, pp. 27-33.

5 Reliability and Safety

The Commission's mission is to ensure full consideration of safety issues and practices related to its policies and proceedings, taking into account the safety of utility personnel, first responders, inspectors, installers and end-users. This is especially true given that there will be more opportunities in the future for customers to seek interconnection of new devices and technologies to the distribution system, and there may be increased involvement of non-utility personnel in the installation and operations of such equipment.

Public Utilities (PU) Code Section 451 requires utilities to furnish and maintain adequate, efficient, just, reasonable service and facilities. The law specifically cites the necessity to promote "safety, health, comfort and convenience" of utility patrons, employees, and the public. PU Code Section 399 declares safe and reliable electric service "utmost importance" to California citizens and the economy, and maintaining safe and reliable service requires prudent investments to be made.

Section 762 requires the Commission to order infrastructure improvements needed to "secure adequate service and facilities" which, through Commission decisions and General Orders, provides the context for ensuring reliability of utility services.

With particular reference to infrastructure upgrades and maintenance, General Order 165 established minimum requirements for electric distribution facilities, regarding inspection (including maximum allowable inspection cycle lengths), condition rating, scheduling and performance of corrective action, record keeping, and reporting, in order to ensure safe and high-quality electrical service.[43] Other general orders that establish rules and standards for safe and reliable utility operations are G.O. 95 and GO 128.

Although safety and reliability are distinct aspects of the Commission's core mission, there is an undeniable overlap and intertwining of the two concepts. Factors that are frequently the cause of disruptions to reliability, including downed lines, equipment failure, lightning strikes and other major weather events, may have direct safety consequences.

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[43] GO 165 was enacted via D.97-03-070 to implement the provisions of Section 364 of Assembly Bill 1890, Chapter 854, Statutes of 1996.

Extended power outages or supply disruptions during extreme summer heat or winter cold could impair the ability of utilities to ensure safe and reliable service to critical facilities, including hospitals, medical facilities, police and fire operations, and to customers who rely on life-supporting medical devices.

In SCE's assessment of risk drivers, outages and prolonged outages are frequently cited as potential outcomes. However, aside from generalized statements, the utility does not provide specific information about the relationship of outages and more relevant safety impacts, including worker or public safety, injuries and fatalities.

For some major program areas, the connections between reliability and safety are more apparent than for others. Among the assets for which SCE has provided some type of risk scoring, the Replacement of Distribution and Transmission wood poles is one that clearly has significant potential mitigation impacts for both safety and reliability. Under the CPUC's General Order 95, Rule 48, a pole failure is a *per se* violation of the safety regulations.

These two programs, Pole Replacement and Grid Modernization represent substantial portions of SCE's GRC spending requests in this application, with significantly increasing proposed budgets forecast through the rate case period.

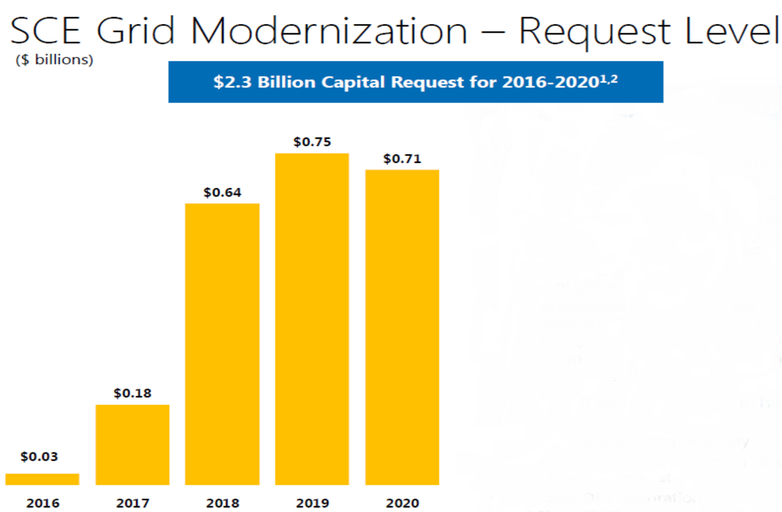
This report has already noted that SCE's risk assessment approach is not fully mature and its testimony demonstrates that the utility did not use risk assessment in the identification of its top risks, or select programs to address those risks, but mostly after-the-fact as a way to measure risk reduction associated with the programs or projects proposed. Further, the funding allocations for risk mitigations were not based on risk analysis.

What follows is a different, more technical analysis of these two areas of risk, which point out other deficiencies in SCE's GRC requested support for these programs.

6 GRID MODERNIZATION

SCE has devoted an entire volume of testimony to it plans for modernizing its distribution grid through investments in automation technologies and reinforcing its distribution network "to enhance safety, cybersecurity and reliability, [to] enable Distributed Energy Resource (DER) adoption, promote customer choice, and realize DER benefits."[44]

Figure 5 Grid Modernization TY2018 GRC Request



SCE's O&M expenses request for TY2018 is a relatively modest $4.6 million, but its proposed capital budget for various Grid Modernization projects would rise substantially, from $34 million in 2016 to $598.2 million by 2020, totaling $1.875 billion in CPUC jurisdictional spending.[45] In all, including revenue requests under federal jurisdiction, SCE forecasts $2.3 billion in capital expenditures for grid modernization in 2016-2020.[46] [47]

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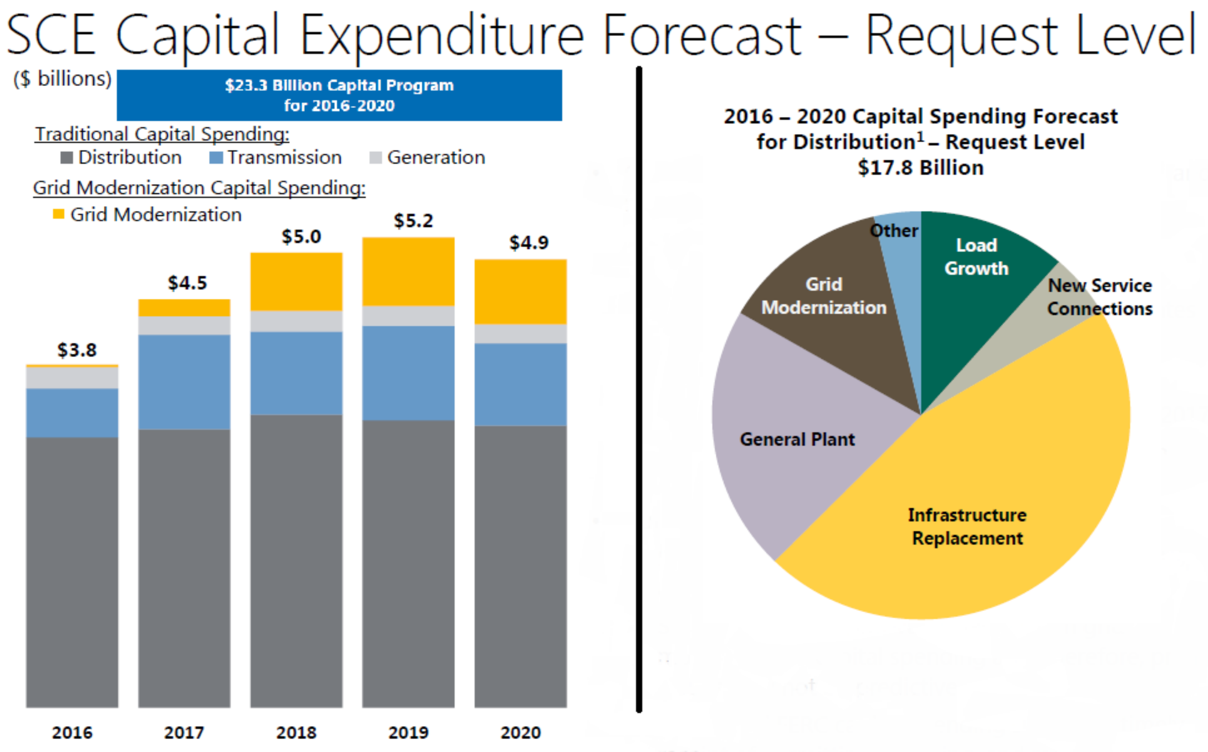
[44] SCE-02, Vol. 10.
[45] SCE-02 T&D-Vol. 10 Grid Modernization, Pg. 35.
[46] SCE Sept 2016 GRC Overview Presentation https://www.edison.com/content/dam/eix/documents/investors/sec-filings-financials/2018-SCE-general-rate-case-overview.pdf Pages 4-6.
[47] Edison International Nov 2016 Business Update http://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-november-2016-business-update.pdf Page 12.

Figure 6 SCE Capital Spending Projections including Grid Modernization



Grid modernization funding requests compete with traditional safety related programs for funding, such as prioritized aging infrastructure replacement.[48] Grid modernization programs might create new cyber and other risks that must be adequately mitigated.

While SED acknowledges that there are safety aspects to SCE's grid modernization proposals, SED also recognizes that grid modernization is typically portrayed as a means to expand integration of distributed energy resources and to improve reliability. In the PG&E 2014 GRC, a report conducted by an SED consultant, Liberty Consulting, highlighted the importance of distinguishing between safety and reliability when conducting safety risk assessment. [49]

While SCE projected improvements in reliability metrics in its testimony from grid modernization, there was no similar projection in terms of improvement in safety metrics.

In its testimony, the utility cited CPUC policies in the Distribution Resources Planning rulemaking to support a modern distribution network that accommodates two-way flows of

[48] Edison International Nov 2016 Business Update http://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-november-2016-business-update.pdf Pages 7 & 11.

[49] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K394/65394210.PDF

power, enables customer choice, and facilitates opportunities for DERs to realize benefits through provision of grid services.[50] SCE also claims its "distribution grid is aging and is facing new strains in the form of greater cybersecurity risks, nearing capacity limits on certain circuits and telecommunications wires, and technology obsolescence….Even without DER growth, grid modernization is needed to maintain SCE's aging distribution grid and improve its reliability."[51]

SCE's arguments hinge on increased reliability and market transformation issues, with scant analysis of safety impacts beyond boilerplate language citing Public Utilities Code provisions to state that "Maintaining system reliability as well as safety of public and utility employees are fundamental responsibilities of the utility."[52]

Grid modernization funding requests may compete with traditional safety related programs for funding, such as prioritized aging infrastructure replacement.[53]

SCE identified seven major categories of program associated with its Grid Modernization request, and indicated sharply increasing expenditures in the GRC period 2016 – 2020.

Table 10 Summary of 2016-2020 Forecast Capital Expenditures CPUC Jurisdictional (000)

Program	2016	2017	2018	2019	2020	Total
Distribution Automation	$10,995	$66,908	$$277,285	$285,863	$293,795	$934,729
SA-3 CSP (substation automation)	$10,385	$50,385	$114,340	$122,109	$123,390	$420,609
Field Area Network (FAN)	$6,998	$17,841	$20,976	$89,336	$108,002	$243,143
Wide Area Network (WAN)	$860	$4,951	$38,985	$38,422	$39,218	$122,436
System Modeling Tool	$4,150	$6,514	$2,488	--	--	$13,152

50 R.14-08-013, DRP OIR at page 4 (August 14, 2014).
51 SCE-02, Vol. 10, pg. 3.
52 PU Code Section 399.1
53 Edison International Nov 2016 Business Update http://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-november-2016-business-update.pdf Pages 7 & 11.

DRP External Portal	$3,370	$1,853	$3,673	--	--	$5,895
Grid Management System	$264	$12,410	$39,801	$$48,827	$33,793	$135,095
Totals	**$34,011**	**$160,861**	**$497,431**	**$584,557**	**$598,198**	**$1,875,059**

6.1.1 EXAMPLE: FIELD AREA NETWORK (FAN)

SCE's Grid Modernization request includes $243 Million in 2016-2020 capital expenditures for a new radio transmission system: Field Area Network (FAN). SCE states the FAN "will allow data and control signals to be sent between the Distribution Automation equipment on the circuit and a transmitter in that circuit's substation from which the data will be relayed to the grid operations control center."

FAN deployment would begin in 2018 and continue through 2020."[54]

In testimony, SCE describes the limitations and vulnerabilities of its existing radio-based NetComm network communications system that was designed 20 years ago.[55] Furthermore, SCE states: "Throughout the FAN deployment, both the NetComm and AMI networks will be maintained in parallel through the DSEEP program until all endpoint devices can be migrated to the new wireless network. Only after all FAN installations have been completed in a geographic area, will the NetComm and AMI infrastructure be decommissioned."

Another alternative considered by SCE was to utilize AMI data and use their data transmission infrastructure. However, this was determined to not be viable for several reasons, including that "its dependency on an insufficiently reliable commercial cell phone transmission network and long delays in data transmission."[56]

SED is disappointed that this AMI infrastructure appears to have a relatively shortened life. SED believed that utilities intended to use AMI Smart Meter data transmitted over this system to pinpoint, isolate, and respond more quickly to outages, improving CAIDI and SAIDI

[54] SCE-02 T&D-Vol. 10 Grid Modernization, Pages 35, 72-73.
[55] SCE-02 T&D-Vol. 10 Grid Modernization, Page 71-72.
[56] SCE-02 T&D-Vol. 10 Grid Modernization, Page 79.

metrics.[57] SED did not find an assessment in testimony on CAIDI and SAIDI reliability improvements achieved since deployment of the current AMI system. SED notes that SCE reported in testimony that it was evaluating a pilot program to leverage its Netcomm radio system and AMI smart meters as one option to mitigate energized wire down risks while avoiding installation of additional hardware.

SED did not find any assessment of potential new risks associated with implementation of the new FAN and any new dependencies based upon deployment of this wireless communications network. SED was unable to compare risks from the existing system and risks from deployment of the FAN. Once the FAN were deployed, and system operation is dependent on it, SCE did not provide an assessment of what impact a FAN failure, FAN attack, or FAN outage could have on distribution operations and the public.

6.1.2 Conclusion

Because SCE did not provide a risk assessment to compare and rank all of its GRC programs, SED was unable to compare how SCE has risk scored its proposed Grid Modernization program relative to funding requests for SCE's traditional infrastructure replacement programs.

While SED acknowledges that there are safety aspects to SCE's grid modernization proposals, SED also recognizes that grid modernization is typically driven as a means to expand integration of distributed energy resources and to improve reliability. While SCE projected improvements in reliability metrics in its testimony from grid modernization, SED did not find that SCE had provided similar projection in terms of improvement in safety metrics.

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. Grid Modernization is intended to improve SCE's ability to support distribution reliability and safety, particularly as customers continue to transition to filling their individual energy needs using customer solar and batteries and distributed energy resources (DER). In this fashion, customers may reduce their utility bills and dependence on gas-fueled generation from the grid.

[57] Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI).

In conclusion, 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.

7 Pole Loading Risk Assessment Methodologies Deficiencies

As described by SCE in its Test Year (TY) 2018 GRC application, the Pole Loading Program (PLP) is an assessment and remediation program, incremental to the Deteriorated Pole Replacement & Restoration Program, that identifies poles for repair or replacement that do not meet pole loading safety factor requirements of General Order (G.O) 95 and SCE's internal design standards, including wind loading in high wind areas of SCE's service territory.[58]

The utility's Distribution & SubTransmission wood poles have been identified as assets with a substantial safety risk component, ranking third among the utility's scored risks, and first in requested mitigation spending of approximately $386 million for capital and $5.47 million O&M for TY 2018 (see Table 9). In determining a 1-year Current Residual Risk (CRR) Score, nearly half of the risk was attributed to safety (509,892/1,097,224). SED does point out that this CRR Score does not distinguish between risks for separate wood pole programs, which means SCE did not provide a discrete CRR score for its Pole Loading Program separate from its Deteriorated Pole Replacement & Restoration Program or any other wood pole program. Hence, it is not possible to relate to this CRR score specifically to the Pole Loading Program.

Table 11 SCE 2018 Poles Replacement GRC Request[59]

SCE Poles Capital Request 2018 (Nominal $000)	
	2018
PL Distribution Pole Replacements	$119,731
PL Transmission Pole Replacements	$24,628
Distribution Deteriorated Pole Replacement & Restoration	$177,355
Transmission Deteriorated Pole Replacement & Restoration	$64,362
Total	**$386,076**

[58] SCE-02, Volume 9
[59] SCE-02, Volume 9, Table I-3, page 6

Specifically, SCE's CPUC-Jurisdictional Pole Loading related capital requests are roughly $150 million for TY 2018.[60] However, SED has discovered the following deficiencies with SCE's pole loading risk assessment methodology:

- TY 2018 pole loading study sample[61] is not a statistically valid random sample;
- TY 2018 and TY 2015 pole loading studies' failure rates cannot be directly compared and any comparisons are inconclusive since the studies have different cohorts;
- SCE's third-party pole loading assessment SPIDACalc software[62] has not been independently verified and validated[63] to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, including modeling telecommunications utilities and other typical Joint Pole Owners (JPO) and renter facilities' and utilizing typical SCE pole structure configurations for its service territory, against G.O. 95 Overhead Line Construction safety requirements;
- SCE did not assess risk separately for varying levels of pole loading risks (i.e. SCE did not provide different failure rates for very high risk poles versus high risk poles versus medium risk poles, etc.) making it impossible to identify which requirements beyond G.O. 95 requirements are attributed to addressing various risk levels.

7.1 Background

In the CPUC's TY 2012 GRC decision,[64] The Commission did not find that SCE's justification for full funding of its requested wood pole intrusive inspection program, (i.e. to inspect for deteriorated poles), pursuant to G.O. 165 inspection standards, was clearly established. Although the full funding request was approved, partly due to the Commission's concern about some possible pole loading related wildfire incidents, the Commission ordered the

[60] SCE-02, Volume 9, Table I-4, page 7.
[61] SCE-02, Volume 9, page 15, and WP SCE-02, Vol. 09, pp. 86-87.
[62] Per SPIDA Software's website, SPIDACalc's Structure Analysis Software utilizes the latest software technology and a geometric non-linear finite element analysis engine to drive pole loading, pole strength, and guying analysis to power clearance evaluations and structural calculations. Reference: http://spidasoftware.com/products/spidacalc_pole_loading/ (1/25/17).
[63] Independent software verification and validation, per Wikipedia, is the process of checking that a software system meets specifications and that it fulfills its intended purpose, carried out by a separate group from the development team. https://en.wikipedia.org/wiki/Software_verification_and_validation (1/27/2017).
[64] D.12-11-051, pages 180-181.

utility to "perform full inspections of a statistically valid random sample of loaded poles, utility-owned and jointly-owned, to determine whether the loads meet current legal standards."[65]

In its TY 2015 GRC application, the utility requested a new Pole Loading Program driven by what SCE claimed to be significant failure risks for approximately 22% of its total 1.4 million poles.[66] SCE's potential risks assessments was largely driven by use of a new computer software tool, called SPIDACalc.

As the CPUC described in its TY 2015 GRC Decision, "pole loading" refers to the calculation of whether a pole meets certain design criteria called "safety factors" based on wind in that location and facilities attached to the pole. G.O. 95 establishes pole loading safety factors for California utilities. Pole loading calculations consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys.[67] In that same decision, the CPUC authorized SCE's proposed pole loading assessment plan and found that "the public interest in quickly developing a more comprehensive understanding of the extent of the overloaded poles outweighs the potential cost deferral advantage of slowing the pace of assessments."[68]

The CPUC's TY 2015 decision also relied on what it considered a "few seminal facts" that were not disputed:[69]

- A significant fraction, nearly 19%, of poles reviewed in SCE's PLP study are overloaded, and specifically failed the bending analysis. The study suggested similar failure rates in SCE's total population of poles. SCE proposed to replace these poles.
- An additional 3% of poles in the study are overloaded and could be repaired through addition or repair of guy wires. Again, the study suggested a similar rate in the total pole population. SCE proposed to repair these poles.
- Overloaded poles present a significant safety hazard and reliability risk.

Based on these and other findings, the CPUC agreed with parties that some form of PLP should be authorized. However, the CPUC did not conclude that SCE had adequately justified

[65] D.12-11-051, OP 17.
[66] A.13-11-003, SCE 2015 GRC, SCE-15, Supplemental Testimony, pages 24-25.
[67] D.15-11-021, Section 7.7, Pole Loading.
[68] D.15-11-021, Section 7.7.2.1, Assessments and Planning (Distribution and Transmission).
[69] D.15-11-021, Section 7.7.3.1.3, [Pole Replacements] Discussion and Findings of Facts (FOFs) Nos. 144-146.

its specific proposal.[70] The CPUC approved approximately 73% of SCE's PLP replacement pole proposal for TY 2015, and it stated SCE must apply for approval of 2016 and later years' PLP capital expenditures in the TY2018 GRC. The CPUC also directed SCE to focus on its early PLP efforts on high hazard areas, considering hazard maps developed in R.15-05-006 and other relevant information.[71] The CPUC also found that PLP assessments should provide factual information about the extent to which attachments contribute to any valid safety or reliability concerns and potentially non-compliance with G.O. 95 standards.[72]

Even before the Commission rendered a decision in that case, the utility discovered a substantive problem with SPIDACalc in the summer of 2015. SCE explained that the results from the pole loading assessments were not consistent with what SCE observed in the field. Therefore, SCE stopped 40,000 replacement poles that were in prefabrication production in September 2015.[73] SCE admitted that it did not inform the Commission of this significant finding until informing SED on April 19, 2016, during a briefing before SCE's 2018 GRC application filing. SED has determined that there was not just a significant issue with the software but also with SCE's internal design standards and design criteria.

As part of its review of the current GRC, SED evaluated SCE's pole loading assessment and replacement program request for safety risks considering how SCE proposes to manage, mitigate, and minimize related safety risks. The first significant issue is that SCE confirmed that its 1,432 pole study did not utilize a statistically random selection of poles across its service territory. Also, when SCE conducted analysis to compare its previous methodology with a revised sampling methodology, it used completely different sampling poles, not the same cohort as in its original analysis. SED concludes that there is no way to do an "apples-to-apples" comparison between the previous pole loading assessment methodology and the new revised methodology.

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[70] D.15-11-021, Section 7.7.3.1.3, page 135.
[71] D.15-11-021, pages 141-142.
[72] D.15-11-021, FOF 151.
[73] Ms. Menon & Mr. McHale, 12/30/2016 phone meeting, stated that SCE saw an increased failure rate in the third quarter of 2015 and determined they needed to stop to assess the previous version. This was also discussed at the April 19,2016 SCE Briefing to SED staff on SCE 2018 GRC Poles and in SCE's 11/2/2016 SCE 2018 GRC "Deep Dive on SCE Testimony on Poles" in this proceeding.

SED concludes that TY 2018 pole loading study sample is not a statistically valid random sample. SED also concludes that TY 2018 and TY 2015 pole loading studies failure rate comparison is inconclusive since the studies have different cohorts.

Therefore, SED recommends the Commission require SED to conduct a pole loading study on an statistically valid sample for SCE's service territory, after conferring with SED Risk Assessment & Safety Advisory engineers, but also after other SED recommendations below are fulfilled.

SED has also determined that SCE's third-party pole loading assessment SPIDACalc software has not been independently verified and validated to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, including modeling typical telecommunications utilities and other Joint Pole Owners (JPO) and renters' facilities' and typical SCE pole structure configurations for its service territory, against G.O. 95 Overhead Line Construction safety requirements. SED acknowledges that there are countless examples of real-life situations for SCE's utility poles, yet SED is concerned that SPIDACalc has only been independently verified per the requirements of the Canadian Standards Association (CSA) Overhead Systems C.22.3 No. 1-15 utilizing typical pole configurations used in Ontario, Canada.

This is concerning to SED as it is unclear whether SCE will continue to revise its pole loading assessment methodology, including utilizing various SPIDACalc revisions, and revising its own design criteria to result in potentially significantly different pole loading assessment results. SED is concerned that both the number of poles to be replaced or repaired could significantly continue to change and possibly even which poles are found to need to be replaced or repaired.

In order to have confidence in SCE's assessment of its pole replacement program, SED recommends the Commission require SCE have an independent engineering firm, with appropriately State of California licensed engineers, verify and validate the SPIDACalc software to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, against G.O. 95 Overhead Line Construction safety requirements. SED recommends that the Commission require SCE require that the independent verification & validation (V&V) process model typical telecommunications utilities and other typical JPO and renters' facilities along with typical SCE pole structure configurations for its service territory. This V&V process would check the software system to ensure that it meets specifications *and* that it fulfills its intended purpose. Design criteria for typical pole configurations and other facilities should minimally include:

- Loading from ruling spans, other spans, phase and neutral wires, telecommunications cables, weather conditions, and overload factors;
- Structure geometry and component properties;
- Detailed geometry of each model analyzed;
- Crossarm properties;
- Conductor/wire properties; and
- Insulator properties.

Finally, SED has concluded that impacts of pole loading requirements due to SCE's internal design criteria, beyond G.O. 95 requirements, have not been separately assessed for risks. Hence, SED recommends that SCE confer with SED Risk Assessment & Safety Advisory engineers with respect to SCE's internal design criteria utilized beyond G.O. 95 requirements. The reasoning is that the Commission should be fully aware of design criteria that impact risk assessments. This is especially the case for a large pole loading replacement and repair program where the costs could impact ratepayers immensely. The proposed program may not necessarily be addressing the greatest safety risks nor the most cost-effective mitigation measures for the utility given the amount of ratepayer funds required.[74] SCE contends it is the only electric utility that has embarked upon such an extensive pole loading assessment program.[75]

SED does acknowledge SCE's foresight and efforts to advance the industry by supporting the advancement of software development to do pole loading modeling and assessments which could be an innovative development. Yet SED is concerned that any forthcoming assessments utilizing new software and potentially continually changing design criteria could not be adequately managing, mitigating and minimizing safety risks associated with pole loading.

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[74] At the CPUC Energy Division Grid Modernization Workshop on 1/24/2017, SDG&E's panelists, Will Speer, stated that SDG&E is piloting "wires down" technology that could enable the utility to detect a fault and de-energize the line(s) before they even fall to the ground. Mr. Speer confirmed off-line that the technology detects unsynchronized phase(s) in 3-phase power systems as another indicator of a possible fault. SED points out that this type of "grid modernization" may make pole loading safety risks rank even less in the future.

[75] SED Staff interviews, 12/15/2016.

7.2 RECOMMENDATIONS

SED recommends the Commission require SED to conduct a pole loading study on an statistically valid sample for SCE's service territory, after conferring with SED Risk Assessment & Safety Advisory engineers, but also after other SED recommendations below are fulfilled.

SED recommends the Commission require SCE to have an independent engineering firm, with appropriately state of California licensed engineers, verify and validate the SPIDACalc software to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, against G.O. 95 Overhead Line Construction safety requirements.

SED further recommends that the Commission require SCE require that the independent verification & validation (V&V) process model typical telecommunications utilities and other typical JPO and renters' facilities along with typical SCE pole structure configurations for its service territory.

SED recommends that SCE confer with SED Risk Assessment & Safety Advisory engineers with respect to SCE's internal design criteria utilized beyond G.O. 95 requirements.

8 OTHER RISK AREAS AND POTENTIAL GAPS IN ANALYSIS

8.1 CLIMATE CHANGE ADAPTATION

SCE does not specifically break out Climate Change as one of its identified risks, although several of its infrastructure replacement and upgrade projects may be considered to contribute to mitigation of climate change impacts, or as ways to adapt to changes in weather, sea-level or energy consumption that are expected to accompany changing climate patterns. To better understand utility efforts, SED staff issued a data request seeking further explanation of programs and expenditures that may be related to climate adaptation.[76]

In its response, SCE highlighted three programs and initiatives "that SCE engages in to plan for, mitigate, and respond to extreme weather events that could be climate change related:

[76] SED-SCE 001, Q.10.

- SCE uses an all-hazards approach, has partnered with the Department of Energy as part of their Partnership for Energy Sector Climate Resilience, launched an internal climate change Initiative, and considers weather related events within enterprise risks to plan for climate change related events.
- SCE has a vegetation management program to mitigate climate change related events such as wildfires and droughts.
- SCE has implemented the Incident Command System to respond to emergency events.

The utility also described its efforts for planning, training, drills, exercises and activations for hazards arising from environmental changes that include wind storms, rotating outages, El Nino, and wildfires.

In July 2015, SCE joined 16 other utilities to voluntarily participate in a U.S. DOE Partnership for Energy Sector Climate Resilience, aimed at enhancing energy security by improving the resilience of energy infrastructure against impacts of extreme weather and climate change. One outcome, according to SCE, was creation of an Adaptation Planning tool that layers climate-impact maps over SCE's energy infrastructure. This tool allows SCE to draw conclusions from climate projections across the entire service territory, and focus on specific facilities and assets. SCE used data sets provided through the State of California's CalAdapt research portal for analysis, but designed the tool to adjust to new data and updated methodologies.

In February 2016, SCE submitted a report to the DOE on the preliminary conclusions of the impact analysis. SCE said it is leveraging the results to better understand potential system impacts, and identify and evaluate cost-effective mitigation strategies. The overarching strategy is to integrate future climate change projections into existing planning processes utilizing the Adaptation Planning tool. A second report was submitted to DOE by the end of 2016 outlining those strategies.

Additionally, SCE reported that its Business Resiliency department has launched an internal Climate Change Initiative aimed at further identifying climate change impacts and more detailed strategies for the future – beyond what was analyzed and developed for the DOE Partnership. This initiative will mature through 2018 to meet annual goals described below:

Table 12 SCE's Climate Initiative Goals

2015	2016	2017	2018
• Joined DOE Partnership • Developed Climate Adaptation Tool using Cal Adapt data	• Completed Initial Climate Impact Analysis and Submitted Report to DOE • Held workshops with internal experts to develop mitigation strategies for identified vulnerabilities • Submit findings to DOE in November	• Update Climate Adaptation Analysis adding in additional climate factors (e.g. soil saturation, population projections) • Further refine actions needed to execute mitigation strategies	• Initiate implementation of climate change strategies

While not explicitly discussed in SCE testimony, this initiative is managed as part of Business Resiliency's Plans and Programs activities.[77] In this testimony, SCE forecast $8 million in TY 2018 O&M to develop and manage its projects, programs and plans supporting emergency planning and response, including but not only the Climate Change initiative. Requested capital for Business Resiliency in the 2016-2020 forecast period is $118 million.

As a point of comparison with expenditures related to mitigating seismic risks, SCE's operational budget calls for about $1.5 million in O&M associated with seismic mitigation in TY 2018, and over $162 million in capital expenses 2016-2020 ($101.4 million for electric infrastructure; $52.3 million for non-electric facilities; and $8.6 million for generation infrastructure).[78]

8.1.1 Risk Assessment of Climate Change

Although SCE did not apply its S-MAP risk assessment methodology to aspects of its Climate Change Initiative, it is clear that the Adaptation Planning Framework described in its reports to the U.S. DOE amount to a form of risk management, based on four milestones:

- Choosing the right data
- Assessing specific vulnerabilities

[77] SCE 07, Vol. 01, page 20
[78] Ibid.

- Identify the Climate risk group
- Determine cost-effective actions

SCE's Climate Change analysis appears to have drawn on numerous sources, ranging from the California Energy Commission adaptation reports to various academic models for assessing how projected changes may affect local communities in the decades to come, then applying these projections to the utility's service territory.

Based on this application, the utility identified a number of expected impacts on its operations, including:

Warmer Temperatures – The eastern border of its service territory may see average monthly ambient air temperatures rise between 7 and 12 degrees F, in the 2070-2099 period, resulting in decreased efficiency in current transmission, distribution and generation systems. Additionally higher temperatures may drive customer demand for electricity, increasing loads on the five major transmission pathways serving Southern California.

Extreme Heat Events – This measure of how many days would be subject to extreme heat, compared to a "business-as-usual" scenario. For example, such days in Santa Barbara could increase from an average of five to over 123; Riverside, currently subject to about 58 such days, might increase to as many as 103 days of extreme heat. Lack of nighttime cooling could cause additional stress on transformers that help serve customer load, as well as decreasing generation unit efficiency, and pose risks to high-voltage transmission lines.

Increased Wildfire Risks – Already subject to an increased risk of wildfires, SCE's territorial analysis projects as much as a tripling of wildfire risks in the Santa Barbara region, but possible decreases in risk in southeastern areas due to vegetation migration.

Sea-level Rise/Inundation – By the end of the century, the coastal areas of SCE's territory could see a 1 to 1.4 meter rise (3.3 feet to 4.6 feet), increasing the threat to utility facilities along the coast, including generation, substations and transmission and/or distribution lines. The analysis indicated that as many as 18 existing substations are at risk for flooding under a 1.4 meter rise scenario.

Precipitation and Snowpack Changes – There will be significant changes to California's water systems as a result of climate change, with both extended droughts and increased rainfall experienced, depending on locations. Impacts could be as varied as limitations to reservoir capacity available for generation, to risks of flooding and mudslides that damage utility facilities.

Although the utility said that it has not completed its analysis of consequences, it indicated that it has begun to study the indirect and direct costs associated with long-term climate change, as well as mitigations to overcome them. This analysis, said SCE, is expected to be completed in mid-2017.

To its credit, the SCE Climate Change analysis has begun to identify potential mitigation measures that should be adopted well in advance of the expected impacts. During "course of action" workshops conducted during 2016, the utility and subject matter experts identified eight major mitigation categories – along with their associated but unquantified cost impacts and prospective benefits – to further explore and begin incorporating into utility planning:

- Build to projected impacts
- Facility relocations
- Individualized facility flood mitigation engineering
- Equipment specifications aligned to future weather models
- Adding equipment to reduce system stress
- Increase focus on distributed generation availability
- Increase reservoir locations and capacity
- Align system specifications with modified weather conditions.

8.1.2 Analysis and Recommendations

Although the Climate Change impact analysis represented by this initiative is characterized as a long-range planning effort, many aspects of the assessment should be incorporated into the utility's risk assessment modeling beginning with the next GRC cycle. The TY 2021 GRC process should explicitly detail costs of conducting the Climate Change analysis and provide preliminary assessments of expected financial consequences and costs of mitigations (and alternatives) for review in the utility's first RAMP filing in 2018. It is certainly not too soon to begin planning for what the Climate Change models generally conclude will be inevitable outcomes.

While several of the mitigations identified above may not require substantive increases in capital outlays, as they relate to planning and improving tolerance specifications for equipment upgrades and replacement that would likely happen in any event, some areas – particularly facility relocations, stress-reduction facility expansion, and reservoir capacity expansion – may require significant capital investments that should planned well in advance.

Because of apparent overlaps with other risk-informed programs – such as facility relocations, distributed resource planning, seismic upgrades, etc. – early identification of adaptive mitigations can be leveraged with other planned investments for maximum benefit and more efficient resource allocations.

Future RAMP analysis and GRC proposals for SCE (indeed, for all jurisdictional utilities) should begin to include Climate Change Adaptation as a cross-cutting risk.

8.2 CYBERSECURITY

SED believes there is a potential gap in SCE cybersecurity mitigation programs.

Cybersecurity encompasses and crosscuts many utility programs including Physical Security, Information Technology (IT), and Operations (Typically referred to as Operational Technology (OT), which includes Industrial Control Systems (ICS)): (OT/ICS). OT/ICS systems include, for example, Supervisory Control and Data Acquisition (SCADA) systems.

SCE describes significant cybersecurity efforts in various testimony, including $308.9 million in 2016 – 2020 for Cybersecurity & IT Compliance capitalized software projects[79] to mitigate cyber threats and to comply with NERC Critical Infrastructure Protection (CIP) standards.[80] This includes approximately $100 million[81] for new cybersecurity for SCE's proposed grid modernization program. SCE categorizes these IT capital investments as:

- Perimeter Defense - $66.3 million
  SCE Perimeter Defense investments include firewalls, intrusion detection systems (IDS), and virtual private network (VPN) servers.
- Interior Defense - $43 million
  SCE Interior Defense investments include internal monitoring and controls to protect against unauthorized users, devices, and software.
- Data Protection - $27.5 million
- SCADA Cybersecurity - $22.6 million

[79] SCE-04 IT-Vol. 2 IT- Capitalized Software, Summary Page.
[80] The North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Standards http://www.nerc.com/pa/CI/Comp/Pages/default.aspx
[81] SCE-04 IT-Vol. 2 IT- Capitalized Software, SCE reported $99.1 million in the Summary and $99.86 million, Pages 30 & 33.

- Generator Interconnection Cybersecurity - $10.3 million
- Grid Modernization Cybersecurity - $99.9 million
- IT Support for NERC CIP Compliance - $39.2 million

In addition, SCE forecast $131.7 million for Corporate Security 2016-2020 capital expenditures for physical security, to protect critical electrical infrastructure, and for NERC CIP Compliance. SCE forecast $26.9 million in operations and maintenance (O&M) expenses for Test Year 2018.[82] Physical Security supports protection of cyber assets.

SCE also forecast $18.1 million for IT Cybersecurity & Compliance operations and maintenance (O&M) expenses for Test Year 2018.[83]

Although spending for programs cybersecurity is largely embodied in transmission rate cases decided by the Federal Energy Regulatory Commission, and T&D requests before the CPUC, a variety of federal and state agencies influence the direction and extent of utility programs. The Department of Energy (DOE), Department of Homeland Security (DHS), Department of Defense (DOD), California Independent System Operator (CAISO), The North American Electric Reliability Corporation (NERC), the Office of the Director of National Intelligence, plus others, all play a role in promoting protection of the electric grid from cyber threats.

The energy sector has become a major focus for cyber-attacks. SCE indicates that it has experienced a ten-fold increase in cyber intrusions over the last 3 years.[84] A successful cyber-attack on the Ukrainian power grid in December 2015 forced 225,000 customers to lose power. SCE underscored the risks and vulnerabilities of grid control systems in its testimony.

SCE described the Ukrainian attack through news articles submitted in its workpapers, which recounted the incident and raise questions about the resiliency of U.S. electric utility networks and their ability to restore power following a successful attack due to a lack of manual backup functionality. The situation additionally has raised concerns in the U.S. Congress.

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[82] SCE-07 Operational Services-Vol. 5 Corporate Security, Page 1.
[83] SCE-04 IT-Vol. 1 IT- O&M and Hardware, Summary Pie Chart and Page 18.
[84] SCE-04 IT-Vol. 2 IT- Capitalized Software, Figure III-3, Page 16.

8.2.1 OT/ICS Cyber Mitigation

SED is concerned that there is a potential gap in SCE mitigation of Cyber Risks of SCE's Operational Technology/Industrial Control Systems (OT/ICS). Utility OT/ICS systems may have portions under the jurisdiction of multiple utility Operating Units (OUs), including the Transmission & Distribution Operating Unit, the Information Technology (IT) Operating Unit, or both. Jurisdiction may include design, procurement, maintenance, operations, physical security, risk ownership, and more.

At SCE, the Cybersecurity & IT Compliance (C&C) organization oversees regulatory compliance activities across IT. C&C encompasses significant efforts to prevent successful cyber attacks. In a meeting with SED staff, SCE reported that it employs significant efforts to prevent and isolate cyber intrusions.

DOE has developed several cybersecurity guidelines, including guidelines for ICS procurement.[85] Effective cybersecurity mitigation must often be designed in, and may encompass multiple utility Operating Units.

Subsequent to the successful Ukrainian attack, DHS released Alert (IR-ALERT-H-16-056-01).[86] The DHS released a follow-up alert, IR-ALERT-H-16-043-01AP, the following month.[87] These alerts recommended specific mitigations for utilities, which included implementation of best practices encompassing procurement, licensing, asset management automation, software patching and strategic technology upgrades. The Ukrainian outage alerted utilities to OT/ICS infrastructure vulnerabilities and risks, should an attacker breach IT or Security controls.

In particular, DHS recommended:

"Organizations should develop and exercise contingency plans that allow for the safe operation and/or shutdown of operational processes in the event that their ICS is breached. These plans should include the assumption that the ICS is actively working counter to the safe operation of the process. While the Ukrainian companies did not have such a plan prepared,

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[85] https://energy.gov/oe/services/technology-development/cybersecurity-for-energy-delivery-systems
https://energy.gov/oe/services/cybersecurity
https://energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014

[86] https://ics-cert.us-cert.gov/alerts/IR-ALERT-H-16-056-01

[87] http://www.eenews.net/assets/2016/07/19/document_ew_02.pdf

their experience with manual operation of their distribution systems allowed them to quickly recover. As US infrastructure is generally more reliant on automation, a comprehensive plan is needed to ensure safe operation or shutdown of processes under this condition."

SCE has identified cybersecurity as a significant risk in its GRC testimony, although it did not provide any detailed risk assessment or scoring. While compliance rules evolve slowly, SCE would need to conduct appropriate risk management processes to timely and effectively respond to emergent or under-scored risks. SED also did not find that any SCE OU had formally assessed the contingency plans and mitigation measures recommended by DHS.

SED believes that review, assessment, and potential adoption of some of the mitigation measures recommended by DHS would appropriately reside in SCE's Transmission and Distribution Operating Unit (T&D OU).

8.2.2 Recommendations

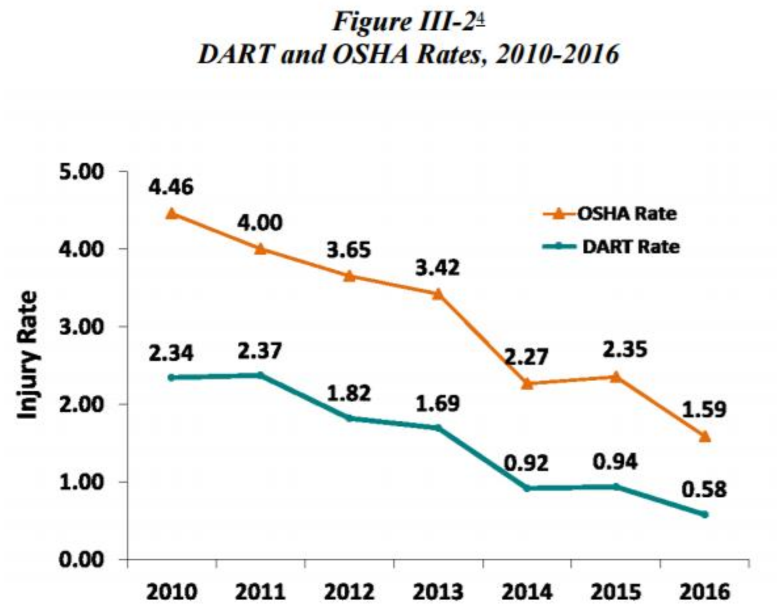
SED recommends that SCE formally assess these particular DHS alerts and recommendations and develop mitigations as appropriate. SED recommends that SCE develop a plan to ensure that cybersecurity alerts from various entities that substantially impact T&D operations are formally processed by the T&D OU. SED believes that SCE T&D should develop sufficient resources to review, assess, and implement potentially significant mitigation measures as appropriate.

9 Safety Performance Metrics

Various metrics may be used to assess safety performance. In testimony, SCE reported improvement for OSHA Recordable and DART injury rates from January 2010 to June 2016: [88]

[88] SCE-07 Operational Services (OS) Volume 04 – Corporate Health and Safety:
"DART incident rate is the sum of restricted duty and lost time injuries that result in at least one whole day away from work after the date of the incident."
"OSHA Recordable Incidents are work related injuries and illnesses (including lost time injuries) that result is loss of consciousness, restricted duty, job transfer, medical treatment beyond first aid, fatality or a significant injury or illness diagnosed by a physician or other licensed health care professional."

Figure 7 SCE DART and OSHA Rates 2010-2016



SCE also reported a 45% improvement in employee safety performance in 2014 over the prior year.[89]

SCE provided the following data in response to an SED data request: [90]

Table 13 SCE SIF Summary 2011-2016

Serious Injuries or Fatalities (SIF) Summary

Year	Employee SIF Count	*Contractor SIF Count	Public SIF Count
2011	8 incidents (10 employees)	Not tracked	16 incidents (20 people)
2012	3 incidents (3 employees)	Not tracked	18 incidents (18 people)
2013	2 incidents (2 employees)	Not tracked	8 incidents (8 people)
2014	5 incidents (5 employees)	5 incidents (7 workers)	20 incidents (22 people)
2015	7 incidents (7 employees)	17 incidents (19 workers)	13 incidents (14 people)
2016 Sep	7 incidents (7 employees)	6 incidents (6 workers)	8 incidents (9 people)

*Corporate Health and Safety (CHS) began tracking contractor incidents in June 2015

While both serve as safety performance metrics, SED notes that trends in SCE Employee Serious Injuries and Fatalities (SIF) data appear inconsistent with trends in Employee DART and OSHA recordable data.

[89] SCE-07 Operational Services (OS) Volume 04 – Corporate Health and Safety, Page 5.
[90] SED Data Request Response: SED-SCE-002-DR1610007-01 Q.03.b Answer.pdf; SCE-14 Safety & Risk Supplemental Testimony Appendices, Page A-127.

9.1 INCOMPLETE ANALYSIS OF SAFETY METRICS

Risk management effectiveness can be assessed using a number of safety metrics. Safety metric data can include both "Leading" and "Lagging" indicators. "Lagging indicator" safety metrics may include fatalities, serious injuries, lost work days, incidents, outages, and more. "Leading indicator" safety metrics may include safety reports, near-misses, quality control, backlog, and more. Lagging Indicator metrics help to prevent recurrence of incidents. Leading Indicator metrics help to prevent incidents that may not have occurred in the past.

SED did not find sufficient information in testimony and document request responses to demonstrate that SCE had a structured enterprise-wide program for analyzing safety metric data and then use that data to prioritize and develop its funding requests for mitigations to improve safety.

9.2 RISKS ASSOCIATED WITH METRICS

SED did not conduct an audit or analysis of SCE safety performance metrics. SED however notes potential risks associated with the adoption of safety performance metrics, especially if they are used to derive financial incentives to employees or the company. Metrics associated with explicit or implicit financial incentives may drive unintended or undesirable behaviors that are detrimental to safety.

Examples include:

A. Incentives associated with OSHA Recordables may drive underreporting of injuries, leading to lost opportunities to identify risks, develop lessons learned, and mitigate risks. As one example, in Commission Decision D.08-09-038, the Commission penalized SCE for violations of PUC Code and Performance Based Ratemaking (PBR) Standards, finding, "In a number of interviews, employees and supervisors stated that safety incentive programs acted as a disincentive for injury reporting." [91] D.08-09-038 also recognized the value in ensuring that safety incidents are not underreported: "Collecting first aid data is much more than an exercise in record keeping; it has a direct bearing on health and safety. There is a relationship between near misses, first aid incidents, more serious injuries, and a fatality. Near misses, first aids, and other data related to minor

[91] SCE I.06-06-014, D.08-09-038, pg. 59.

injuries are informative in terms of preventing major injuries; collecting data on such minor injuries improves health and safety outcomes." OSHA also recognizes this, and prohibits companies from providing safety incentives that lead to underreporting of injuries.[92]

B. A focus on lagging indicator metrics such as injury rates may drive funding toward some programs at the expense of higher risk mitigation programs. Dam integrity may serve as an example of a high-risk mitigation program that requires substantial investment even in the absence of lagging indicator dam failures.

C. Incentives associated with number of gas system leaks have led to underreporting of leaks and a greater number of unmitigated leaks. As one example, PG&E ended a leak based incentive system after employees claimed underreporting of leaks at a 2007 PG&E shareholders meeting.[93] A consultant report provided to SED staff in the 2014 PG&E GRC stated: "PG&E 'recognized that this metric could theoretically operate as a disincentive to implementing an aggressive leak survey program' and eliminated the metric in 2008."[94]

D. Incentives associated with employee health & safety data, and customer satisfaction data have led to fraud. The Commission penalized SCE in 2008 after SCE self-reported issues with its incentive based Performance Based Ratemaking program. Decision D.08-09-038, referenced above, described how incentives, without adequate controls, drove reporting of fraudulent customer satisfaction and other data,[95] and ordered a $32 million recapture of incentives claimed by the utility.[96]

E. Naturally inherent work productivity incentives associated with inspection rates, without adequate controls, have led to fraud in inspection records and uninspected facilities. As an example, PG&E reported finding fraudulent underground inspection records beginning in 2010.[97] Productivity metrics, without adequate controls to monitor quality, can be detrimental to safety.

F. Productivity and cost containment metrics without adequate concurrent metrics to capture impacts on backlog and quality control have degraded safety. As an example, a gas

[92] https://www.osha.gov/as/opa/whistleblowermemo.html
https://www.osha.gov/recordkeeping/finalrule/interp_recordkeeping_101816.html
http://www.lexology.com/library/detail.aspx?g=ced594b5-93f9-45da-b187-b7df3da71d99
[93] http://www.sfgate.com/news/article/PG-E-incentive-system-blamed-for-leak-oversights-2424430.php
[94] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M066/K068/66068555.PDF Pg. 9-11.
[95] http://articles.latimes.com/2008/sep/19/business/fi-edison19
[96] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/91249.PDF Page 2.
[97] http://www.sfgate.com/bayarea/article/PG-amp-E-says-workers-lied-about-inspections-4117503.php

distribution financial audit conducted in the 2014 PG&E GRC found significant reduction in gas employee staffing prior to the San Bruno explosion with inadequate metrics to capture the resulting impacts on quality and backlogs.

The financial audit reported:

- The lack of key operating metrics, such as work order backlogs and late locates, increased the difficulty of evaluating staffing adequacy.
- The metrics used by management were focused on reducing unit costs instead of improving work quality. [98]

9.2.1 Recommendations

SED recommends that SCE review its portfolio of metrics and incentives and ensure that:

A. There are sufficient controls to prevent fraud
B. Safety events and issues are not underreported
C. Resource reductions do not degrade quality, backlogs or safety
D. Incentives do not drive unintended behavior

SED also recommends that SCE develop and implement a structured program for analyzing safety metric data, use that data to prioritize and develop its funding requests for mitigations to improve safety, and report on that data in its rate case application.

10 Gradualism

SED is concerned that SCE's "gradualism" proposal to shift depreciation related expenses from this GRC application, potentially in excess of $4 billion,[99] to future rate cases would inhibit the ability of future ratepayers to fund utility safety programs necessary to maintain SCE's increasingly aging infrastructure.

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[98] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M066/K068/66068555.PDF Pages 14-2 to 14-8.

[99] SED uses a rough estimate of $1.4 billion per year based upon SCE's data response:
SED-SCE-002-DR1610007-01 Q.10 Answer.pdf
SCE states: "SCE's gradualism proposal, if adopted, would recover less depreciation expense than the depreciation study would justify, leaving to future ratepayers the burden of recovering it." "Instead of collecting $7.3B in total revenue requirement using an "untempered" depreciation proposal, SCE would recover $5.9B in revenue requirement. The impact on future revenue requirement is less clear because additional factors would bear on the pace of cost recovery for depreciation expense, …"
http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/D44C8A397930C0938825808E007E7674/$FILE/SCE-14%20Appendices.pdf, Pages A-276-277.

In testimony, SCE stated that in the 2015 SCE GRC Decision, the Commission directed SCE to conduct a more detailed "per-unit" analysis of its cost of removal for at least five of SCE's largest plant depreciation expense accounts. SCE stated: "A key assumption in this analysis is the per-unit cost to retire each asset." SCE acknowledged the uncertainties in its analysis, and stated: "By moderating <capping> SCE's depreciation expense, the Commission will make progress towards SCE's current estimate of forecast net salvage while permitting the Company in future rate cases to rely on additional data to refine its forecasts."[100]

We also note that the 2015 GRC decision stated:

"Third, we recognize that this is at least the second consecutive GRC that the Commission has expressed serious concern with the quality of SCE's depreciation showing. In order to motivate SCE to take these concerns seriously in developing its direct showing for its next GRC, we encourage ORA and TURN (and any other interested party) to consider making proposals in that GRC to shift a portion of the under-collection risk from future customers to SCE's shareholders. Parties should only make such proposals if SCE's direct showing in the following GRC exhibits the same types of shortcomings, discussed here and in D.12-11-051, in a widespread manner." [101]

SCE's gradualism proposal potentially creates a new risk that SCE did not assess. SED is concerned that under gradualism, funding for highly ranked safety risk mitigations in future rate cases would be supplanted by funds approved for lower safety risk ranked utility programs in this rate case. For example, if gradualism were disallowed, funding levels for grid modernization and other SCE programs that may have a lower safety risk ranking may then necessarily be reduced in this rate case to achieve an equivalent ratepayer impact. Future rate cases would be relieved of the burden to pay for past rate case deferred expenses, increasing the ability of future ratepayers to fund anticipated increasing costs of an aging infrastructure.

Decisions on gradualism should recognize the substantial impact on funding for safety programs in future rate cases.

[100] SCE-09 Vol. 3 SCE Asset Depreciation Study, Page 8.

[101] D.15-11-021, Pages 398-399.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M155/K759/155759622.PDF

Shifting current expenses to future rate cases would displace funding that would otherwise be available to fund safety and emergent risk programs identified in those rate cases. For example, if gradualism expenses were not deferred, robust risk assessment in this rate case may determine that a particular reliability enhancement may not be funded in order to fund higher risk programs and to limit ratepayer impact. By shifting expenses to a future rate case, and absent a risk assessment on the impact on safety in a future rate case, the funding of that particular reliability enhancement in this rate case may instead be allowed.

In this fashion, gradualism, and deferral of expenses to future rate cases, would displace funding that would otherwise be available in a future rate case to mitigate higher risks, such as aging infrastructure and emergent risks.

SCE attributes the majority of its gradualism expense deferral to the increasing cost to remove existing equipment that is being replaced.[102]

As two examples: [103]

FERC Account 364: Distribution Poles, Towers, and Fixtures:

SCE lists January 1, 2016 gross plant at $2.5 billion. Under gradualism, the estimated future net salvage value is -$6.5 billion (negative because the cost to remove is greater than the salvage value). Had SCE'S negative salvage ratio (NSR) not been capped under gradualism, it appears the estimated net salvage value should really be -$12.0 billion to reflect the study-based true cost of removal.

FERC Account 367: Distribution Underground Conductors & Devices

SCE lists January 1, 2016 gross plant at $5.6 billion. Under gradualism, the estimated future net salvage value is -$4.2 billion. Had SCE's NSR not been capped under gradualism, it appears the estimated net salvage value should really be -$14.4 billion to reflect study-based true cost of removal.

[102] https://www.edison.com/content/dam/eix/documents/investors/sec-filings-financials/2018-SCE-general-rate-case-overview.pdf

[103] SED derived these figures based upon values and percentages listed in SCE-09, Vol 3, Pg 7, Table I-2 and Workpapers SCE-09, Vol 3, Chapters I,II,II.B, Book A, Annual Accrual Rate Determination Table, Pg 63.

If the study is accurate, SED anticipates that under gradualism, these differences in the true cost of removal will be passed on to future ratepayers.

SED believes depreciation expenses should appropriately be borne in the rate case in which it they are estimated, incurred, and authorized.

SED believes denying deferral would promote:

1. Accountability in developing and vetting of accurate depreciation studies
2. Greater accountability and accuracy in assessing the costs of asset removal
3. Greater efficiency in utility efforts to reduce removal costs
4. More effective risk assessment and funding of programs that have a greater impact on safety when assessing various programs with lower impacts on safety that compete for ratepayer funding.

Without gradualism deferral, GRC parties may reasonably be expected to undertake greater scrutiny of removal costs. Greater scrutiny could then promote efficiencies in removal and replacement, identification and development of asset life extension alternatives, and improvements in new design to reduce future removal and replacement costs.

SED is unaware of any other rate case application that rises to the magnitude of deferral of current rate case expense to future ratepayers. SCE references D.14-08-032 from the PG&E 2014 GRC. In that proceeding, the Commission allowed gradualism, but noted economic circumstances that supported deferral: "We are imposing new costs at a time when many customers have still not recovered from the severe economic recession that began in 2009." "Imposing large negative net salvage cost increases raises similar concerns within the current economic environment which continues to be very difficult for many consumers."[104]

The decision, however, noted that application of this approach should be considered in light of future economic conditions: "Depending on conditions prevailing in future GRC cycles, ratepayers may be better positioned to absorb…cost increases in comparison to today's customers."[105]

[104] D.14-08-032, page 599.
[105] Ibid. page 600.

10.1 Recommendation

While gradualism is a rate impact mitigation tool that the Commission may elect to employ in the course of the unique circumstance of a rate case proceeding, SED believes the Commission may wish to discourage utilities from including it in their risk management based funding requests and rate case applications.

SED cautions against accepting SCE's proposals for gradualism deferral without a risk management process to reassess its program requests.

11 Other Safety Programs

11.1 Safety Culture Improvement programs

SCE states: "In 2015, we implemented our Safety Roadmap, a comprehensive approach to overhauling our safety systems and models, and reinforcing and enhancing our entire safety culture. We expect all employees, but especially all leaders, to be accountable for safety. This includes their own safety, their team's safety, and of course the public's safety." [106]

In 2014, SCE conducted a triennial Safety Culture Assessment, using a new vendor, Behavioral Science Technology (BST), and conducted a broader assessment of safety culture, programs, and organization across the enterprise. This assessment led to the development of the Enterprise Safety Program to address enterprise-wide safety culture and safety opportunities. SCE had previously conducted a safety culture assessment in 2011.[107]

Safety culture assessments may be used to trend safety culture, and have value as a leading indicator safety performance metric. Compared to lagging safety metrics, such as injury rates, a leading indicator metric can help inform a company of safety inadequacies in advance so that accidents may be prevented.

[106] SCE-01 Policy, Summary.

[107] SCE 2015 GRC A.13-11-003 Decision D.15-11-021, Page 282: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M155/K759/155759622.PDF

SCE forecast $680,000 for the Safety Culture Assessment using a three-year averaging technique to spread the costs over the three year rate cycle and assessment period. SCE intends to conduct its next safety culture assessment in 2017.

After meeting with SCE staff, SED is concerned that SCE has no apparent plan to repeat a significant number of the survey questions from previous assessments. While SED appreciates that value can come from safety culture assessment program revisions from time to time, SED believes it is important that safety culture surveys retain a core set of questions that remain static to aid in the identification of safety culture trends. Trend data using consistent questions can provide additional insight to inform SCE on the effectiveness of its safety initiatives.

11.1.1 Recommendation

SCE recommends that SCE continue to develop its safety culture program initiatives, and that SCE retain a core set of permanent unchanging questions in its safety culture assessment surveys.

11.2 Craft Close Call Reporting System

SCE launched a Craft Close Call Reporting Initiative in 2013 to improve safety.[108] [109]

Several industries have adopted close call reporting systems to improve safety including Aviation, Rail, Firefighting, and Offshore Oil & Gas. The intent of these systems is to become better informed on risks that may otherwise go unreported, so that lessons may be learned and future accidents prevented. To be successful, these are generally, and necessarily, non-punitive programs with a few explicit exceptions.

SED is aware that some utilities have adopted such reporting systems at the company level, of which SCE's Craft Close Call Reporting system appears to be one. SED considers adoptions of such programs a safety best practice. SED staff are assessing potential application of such a system at an industry regulator level for California energy utilities.[110]

[108] SCE-02 T&D-Vol. 12 Safety - Training & Environmental Programs, Page 7.
[109] SCE-14 Appendices, Pages A-163 thru A-214.
[110] https://web.archive.org/web/20150327181541/http:/www.cpuc.ca.gov/PUC/CPUC_Workshop_on_NASAs_Aviation_Safety_Reporting_System.htm

SED observed that SCE's close call reporting system does not offer some of the protections or attributes offered by other safety reporting systems. For example, in the rail industry, workers are provided explicit protection from disciplinary action, except for specific events, such as intentional acts to cause damage or injury, criminal acts, substance abuse, or events resulting in accidents or release of hazardous materials. More information may be found on the Federal Railroad Administration's (FRA's) Confidential Close Call Reporting System (C3RS) website.[111]

Workers similarly have limited regulator enforcement protection, excluding accidents and criminal acts, in the aviation industry. More information may be found on the Federal Aviation Administration (FAA) and NASA websites. [112]

Under systems with these protections, the utility may gain additional specifics of a near miss event in order to improve its ability to understand the root causes and develop corrective actions to prevent accidents.

11.2.1 Recommendations

SED recommends that the Safety Reporting/Close Call program be broadened and funded to include, as appropriate:

- Expansion to all worker classifications
- Root Cause Analysis
- Corrective Actions
- A process, or root cause analysis, to use safety reports to then revise or develop new programs, procedures, and training
- A process, or root cause analysis, to use safety reports to then revise or develop new designs, safeguards, and procurement

[111] https://www.fra.dot.gov/Page/P0751
[112] http://www.asias.faa.gov/pls/apex/f?p=100:43:0::NO::P43_REGION_VAR:1
https://asrs.arc.nasa.gov/overview/immunity.html
https://www.law.cornell.edu/cfr/text/14/91.25

12 PUBLIC UTILITIES CODE SECTION 750

12.1 BACKGROUND

PU Code Section 750 states, "The commission shall develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation. The procedures shall include a means by which safety information acquired by the commission through monitoring, data tracking and analysis, accident investigations, and audits of an applicant's safety programs may inform the Commission's consideration of the application."[113]

The Commission collects data from electric and gas utilities through audits, investigations, and incident reports that utilities are required to submit.

Although the Commission has not adopted a formal process, SED has used the Risk and Safety evaluation report as a vehicle for identifying this type of safety information for consideration, as relevant, to each GRC. Over time, the analysis of this data is expected to better inform the decision making process.

12.2 ELECTRIC INCIDENT REPORTING

Electric utilities must report electric incidents (accidents involving electric facilities), which meet any of the criteria below:

- A fatality or injury involving electric facilities
- Damage to property of the utility or others in excess of $50,000
- Significant media coverage
- A major outage to at least 10% of the utilities entire service territory is experienced at a single point in time

In general, the electric utility must report these types of incidents to the CPUC within two (2) hours of their occurrence.

The Electric Safety and Reliability Branch (ESRB) investigates these incidents to enforce the CPUC's rules and regulations and to determine how to limit the occurrences of

[113] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB900

such incidents in the future. ESRB produces an investigative report for each incident reported and investigated.

As one part of our efforts to address PU Code Section 750, we reviewed the ESRB's Electric incident database for SCE from 2011-2016.[114]

For SCE, there was an average of two violations per year found in incident reports that resulted in injuries or fatalities. The database shows that twelve incidents with fatalities – approximately 29% of incidents with fatalities – involved violations. In addition, fourteen incidents with injuries – 14% of incidents with injuries in the same time period – involved violations. Most of the violations were related to failure to adhere to General Order 95 and General Order 165 rules.

The table below summarizes incidents that involved injuries/fatalities from 2011-2016.

Table 14 SCE Electric Incidents with Injuries/Fatalities

Number of Electric Incidents with Injuries and/or Fatalities by Cause	2011	2012	2013	2014	2015	2016	Total
Utility Work	5	7	16	9	8	4	**49**
Contact by Third Party	7	7	4	11	7	4	**40**
Equipment Failure	6	2	-	3	-	1	**12**
Contact w/ foreign object	1	2	1	5	2	2	**13**
Theft/Vandalism	3	5	-	1	6	-	**15**
Fire	-	-	1	1	-	-	**2**
Unknown	-	2	-	5	1	1	**9**
Total	**22**	**25**	**22**	**35**	**24**	**12**	**140**

Incidents resulting in injuries and fatalities are frequently associated with contact by a third party with electrical facilities. These are generally a result of non-utility workers inadvertently contacting overhead electric lines. Activities range from an aluminum pole of a

[114] The electric incidents database has not been verified for accuracy. The database has not typically been used to aggregate data and assess trends, and is typically used to review individual incidents and their associated report.

window washer coming into contact with an overhead line, a tree trimmer contacting an overhead line, an amusement park ride constructor inadvertently contacting an overhead line. Injuries by non-utilities workers include accidental dig-ins, tree trimming, and human error. These types of incidents happen on average seven times per year.

SCE addresses this in its GRC testimony:

"Infrastructure evaluation, maintenance, and replacement programs that mitigate the risk of system failure contributing to a public safety incident such as Overhead Conductor Program and wire down reductions efforts are managed and maintained by Transmission and Distribution (SCE-02, Volume 08).

"Outreach programs to provide education and essential information to the public include billboard, radio, mailer, and television campaigns in multiple languages. External safety communication programs are developed and maintained by Corporate Communications (SCE-08, Volume 02) and focus on topics such as not releasing Mylar balloons, maintaining ten feet of clearance from our lines, not touching downed wire, calling before you dig '811' program, preventing contact with a downed wire. SCE also provide educational seminars for communities, schools, and fire departments on the dangers of electricity."[115]

Incidents are also commonly associated with utility work. Although these incidents many times do not result in a violation, it is possible that injuries and fatalities could be prevented if workers and subcontractors followed SCE's guidelines and procedures more closely. Utility work incidents occur on average eight times per year over five and a half years.

SCE addresses Contractor safety in its GRC testimony stating:

"In 2015, SCE implemented a contractor safety program, which established four key changes in how we approach safety. The program spearheaded the practice of SCE holding contractors to a standard of safety performance consistent with the standard to which we hold employees. When a contractor is first brought on, and at each subsequent annual review, contractors performing high risk work must have an experience modification rate (EMR of less than 1.0 (1.0 is the industry average.) Contractors with an n EMR greater than 1.0 will receive more scrutiny and may not be awarded a contract.

[115] SCE-07, Vol. 04; p.7-8

“SCE personnel must have multiple touch points for safety engagement with contractors. This encompasses pre-job qualification and safety briefings, on-the-job monitoring, post-job safety evaluations, and SCE- sponsored contractor safety forums.

“We implemented visibility and oversight measures concerning contractor safety incidents. Contractor safety incidents are now recorded in SCE’s safety incident management system, reviewed on the Edison Safety Scorecard, and scrutinized so that SCE can complete appropriate root cause analysis and develop actions to prevent future events.”[116]

SCE’s ERM (Enterprise Risk Management) Risk Register correlates with the results of the Electric Incident Database. ERM Risks include aging infrastructure, attack on infrastructure, employees not following procedure, failure of equipment, and theft all identifying possible direct outcomes of public injury/fatality. Having these risks identified will aid in informing funding requests by incorporating safety as part of the equation.

12.3 Electric Audits

In addition to incident data, the CPUC regularly audits the electric systems of utilities to insure the utilities are complying with the law and the Commission’s general orders. Electric audits are conducted to ensure that an electric utility is following the construction, maintenance, and inspection requirements outlined in GOs 95, 128, 165, and 174.

Electric audits are comprised of three different types of audits:

- Distribution (between 4 and 35 kilovolts) – GOs 95, 128, and 165
- Transmission (above 35 kilovolts) – G.O. 95, 128, and 165
- Substation – GO 174

ESRB staff normally conducts audits of electric utilities, or in the case of the largest utilities, their regional units every five years. ESRB may increase the frequency of audits based on any significant problems found. A typical audit lasts five days, depending on the size of the utility or unit.

During an audit, ESRB engineers review utility records and perform field inspections of utility facilities. The primary focus of the records review is to check the utility for compliance

[116] SCE-07, Vol. 04; p.7-8.

with General Order requirements and to find systemic problems in the utility's compliance procedures. The field inspection focuses on verifying records provided by the utility and on performing quality assurance on the work done by utility employees.

Within 30 days of the audit, ESRB issues an audit summary to the utility.117 The summary includes all violations noted during the audit and an explanation of the finding. Utilities have 30 days to respond to the audit summary with a plan to correct all noted violations.

The Electric Audits databases are not currently structured to be able to view aggregated data and determine trends. In 2016 SED Staff have updated the database to include two new fields; record violations count and field violations count. These are two types of violations found during an audit. Record violations can be described as an issue with the maintenance and inspection program. This can also include missing records, incomplete records, forged documents, etc. Field violations are violations of the General Orders that are found during physical inspections. These two new fields count the number of record and field violations found during an audit. However, it would be difficult to draw conclusions/trends from just those two fields.

12.4 Citation Program

The Commission adopted D. 14-12-001 in December 2014 (modified by D.15-05-054) establishing an electric safety citation program for General Orders 95, 128, 165, 166, 174, or other decision, code or regulation allegedly violated, satisfying the requirement in Senate Bill 291 (Stats. 2013, Ch. 601). [118] These citation programs provide important data on serious safety violations by a utility.

In December 2014, the CPUC issued D. 14-12-001 to permit CPUC staff to fine electric corporations for violating state rules and regulations. Citations may arise out of an ongoing investigation or when a violation is directly brought to the CPUC's attention. D. 14-12-001 implements an electric safety citation program that is consistent with the requirements included in Senate Bill 291.

[117] http://www.cpuc.ca.gov/General.aspx?id=2065
[118] This bill added PUC Section 1702.5 to provide for citation authority for electric and natural gas incidents.

12.4.1 Electric Citations

SED has issued one safety citation to SCE since the inception of the program, levying a $50,000 penalty for an incident in May 2014.   PG&E has received two electric citations.

On May 15, 2014, an SCE overhead conductor separated and fell to the ground. A member of the public contacted the downed conductor (which was energized) and as a result was electrocuted. SED's investigators found that the overhead conductor separated at an overhead connector, and that SCE did not maintain the connector for tis intended use. SCE was found to be in violation of G.O. 95, Rule 31.1.

It is important to note that the citations detail immediate corrective actions taken by the utility, as opposed to actions to be taken at a later date in a proceeding such as the GRC.

12.5 Accident Investigations

At the time of this report there are two open investigations before the Commission:

- I.15-11-006 Commission Investigation into September 30, 2013, incident at a Huntington Beach Underground Vault.[119]
- I.16-07-007 Investigation Report of Outages during July and August 2015 in the Long Beach District.

The Commission has not made any findings of fact, conclusions of law, or orders in either of the above proceedings.

12.5.1 Huntington Beach

On September 30, 2013, an apprentice lineman employed by CAM Contractors (CAM), a subcontractor to Southern California Edison Company (SCE), was fatally injured when he inadvertently removed an energized dead-break elbow while working in an SCE underground vault located in Huntington Beach, California. ESRB's investigation revealed that SCE's current safety program does not ensure that its contractors and subcontractors are performing work in a safe manner.[120]

[119] *Investigation Report of the September 30, 2013 Subcontractor Fatality at SCE Underground Vault in Huntington Beach*

[120] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K541/157541534.PDF

On December 15, 2016 SCE and SED ESRB filed a Joint Motion for Approval of Settlement Agreement.[121] The proposed agreement address ESRB's finding in the following way:

1. SCE will enhance its Tier 1 Contractor Safety Program by retaining a Third Party Administrator (TPA) which will be responsible for evaluating all current and future contractors and subcontractors.
2. The TPA will evaluate the safety qualifications of contractors and subcontractors using and expanded set of criteria that includes Total Recordable Incident Rate (TRIR), Days Away, Restricted or Transferred (DART) rate, Experience Modification Rate (EMR), 5-year fatality history, and 3-year Occupational Health and Safety Administration (OSHA) repeat citation history. The expanded criteria will be compared quantitatively to industry averages.
3. SCE will define safety scoring requirements that will rank contractors as high, medium, or low based on the TPA's evaluation. Contractors ranking medium will be considered Conditional Contractors subject to additional review and other requirements in order to be retained.
4. For Contractors and Subcontractors requiring expedited retention senior management approval is required.
5. SCE will increase the frequency of observing contracted field work by Edison Representatives or their designee.
6. Contractor Safety Quality Assessments will be performed on a periodic basis under the direction of Corporate Health & Safety on Tier 1 contractors.
7. Safety and Environmental Specialists will conduct field observations and assessments.
8. Corporate Health & Safety management will be responsible for reviewing lessons learned and corrected actions from incidents involving contractors and subcontractors.
9. SCE shall submit quarterly reports to SED regarding progress, implementation and performance of the above enhancements every two years after the Settlement is final.

In SCE's testimony, four key changes to contractor safety program are discussed. However, the future spending impacts of the proposed agreement was not addressed in the testimony, which was filed prior to the settlement agreement.

The proposed agreement may impact SCE's future spending on operations and training, specifically CH&S, and TPA.

12.5.2 Long Beach

During July and August of 2015, in a period of high temperatures and electrical demand, Southern California Edison Company's (SCE) electrical system serving downtown Long Beach experienced multiple significant power outages, including a five-day outage from July 15 to July 20, 2015, and a four-day outage from July 30, 2015 to August 3, 2015.

[121] SED and SCE Joint Motion for Approval of Settlement Agreement

Along with these outages, electrical problems caused fires in underground structures, resulting in explosions that sent manhole covers airborne. There were no injuries or fatalities associated with these outages.[122]

SED alleged that it discovered serious neglect and deterioration of SCE's Long Beach secondary network, improperly configured protective devices, equipment installed without critical components, deteriorated cables, poorly constructed and failed cable splices, and improperly racked equipment. SED's investigation also alleged that SCE's inadequate knowledge of the secondary network system contributed to longer restoration times. This finding is of great concern because it echoes the Commissions finding in the San Bruno Investigation (I.11-02-016) that PG&E violated American Society of Mechanical Engineers B.31.8, Public Utility Code Section 451, General Order 112, and regulations set forth in Title 49 of the Code of Federal Regulations Part 192 for failing to maintain its gas transmission pipeline records in a manner to allow safe operation of its gas transmission pipeline system.[123]

The utility and SED ESRB requested suspension of the procedural schedule while they pursue a possible settlement agreement. On January 10, 2017, via e-mail ruling, the Administrative Law Judge granted the request and parties were directed to provide a monthly status update on the 10th of each month on the progress of settlement negotiations.[124]

SCE does reference the Long Beach Outage in its testimony prior to a settlement agreement being reached:

"In July 2015, the City of Long Beach experienced outages due to equipment failures in the underground network system. SCE commissioned an independent study of the company's response to this incident to identify areas for improvement by (1) determining the root causes of the network failures and (2) analyzing key aspects of the subsequent response efforts, such as activation, mobilization, escalation protocols, situational awareness, communications, logistics, and restoration strategies. As a result of this study, Business Resiliency tracks and implements corrective actions and recommendations to promote continuous process improvements, including

[122] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K624/164624421.pdf
[123] D.15-04-021; Ordering Paragraph 1.
[124] http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=172519062

the implementation of new standard operating procedures and training for operations personnel on the underground network system."[125]

Potential corrective actions and recommendations will not be known until a Settlement Agreement is filed, as well as the impact of future spending on operations and training.

12.6 Conclusion

Information from the incident reports, audits, investigations, and citation programs may be used to inform the review of SCE's risk assessment methodologies, but this data should not entirely drive the risk prioritization. Specifically, the lack of a citation or reported incident may not indicate the likelihood of a risk occurring or not occurring.

From our review, there are no obvious repeated offenses that would warrant a departure from the risk assessment described in the GRC testimony; however, we do believe it is important to continue to monitor the data to determine if pervasive problems occur in the future that could inform the risk assessment framework.

While this new framework is developing, it may be beneficial to identify the associated risks or risk drivers in incident, audit, and citation reports going forward, so utilities and parties can easily identify whether those risks are adequately accounted for in the risk prioritization process.

[125] SCE-07, Vol.01; p.4-5.

13 Report Recommendations

13.1 Application of Risk Scoring

SCE's risk scoring and risk register need to be aligned. SCE must have a clear idea of what it is scoring and why it is scoring it. It is unclear why SCE is scoring assets that are unrelated to risks that it has identified in its risk register, or why the risk register is missing scored asset risks.

Although SCE self-identifies its risk assessment processes as immature, its risk register, as well as its GRC asks (informed by risk assessment) should all be aligned. There were only two risk register risks for which SCE used risk assessment to inform its current GRC request. This is not enough progress. SCE should greatly ramp up its risk assessment efforts.

In the next GRC, SCE should include some explanation comparing its previous risk register to its current risk register,

SCE should consider whether safety is being adequately prioritized in the results of any future risk scoring methodologies. In the future, it would be useful to compare the test year spending to past year spending.

SCE may use Risk Spend Efficiency to compare mitigations across risks in the future, and we encourage SCE to move in that direction.

13.2 Grid Modernization

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.

13.3 Pole Safety

SED recommends the Commission require SED to conduct a pole loading study on an statistically valid sample for SCE's service territory, after conferring with SED Risk Assessment & Safety Advisory engineers, but also after other SED recommendations below are fulfilled.

SED recommends the Commission require SCE to have an independent engineering firm, with appropriately state of California licensed engineers, verify and validate the SPIDACalc software to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, against G.O. 95 Overhead Line Construction safety requirements.

SED further recommends that the Commission require SCE require that the independent verification & validation (V&V) process model typical telecommunications utilities and other typical JPO and renters' facilities along with typical SCE pole structure configurations for its service territory.

SED recommends that SCE confer with SED Risk Assessment & Safety Advisory engineers with respect to SCE's internal design criteria utilized beyond G.O. 95 requirements.

13.4 Climate Adaptation

The TY 2021 GRC process should explicitly detail costs of conducting the Climate Change analysis and provide preliminary assessments of expected financial consequences and costs of mitigations (and alternatives) for review in the utility's first RAMP filing in 2018.

Future RAMP analysis and GRC proposals for SCE (indeed, for all jurisdictional utilities) should begin to include Climate Change Adaptation as a cross-cutting risk.

13.5 Cybersecurity

SED recommends that SCE formally assess these Department of Homeland Security alerts and recommendations and develop mitigations as appropriate. SED recommends that SCE develop a plan to ensure that cybersecurity alerts from various entities that substantially impact T&D operations are formally processed by the T&D OU. SED believes that SCE T&D should develop sufficient resources to review, assess, and implement potentially significant mitigation measures as appropriate.

13.6 Safety Metrics

SED recommends that SCE review its portfolio of metrics and incentives and ensure that

- There are sufficient controls to prevent fraud

- Safety events and issues are not underreported
- Resource reductions do not degrade quality, backlogs or safety
- Incentives do not drive unintended behavior

SED also recommends that SCE develop and implement a structured program for analyzing safety metric data, use that data to prioritize and develop its funding requests for mitigations to improve safety, and report on that data in its rate case application.

13.7 Gradualism

SED cautions against accepting SCE's proposals for gradualism deferral without a risk management process to reassess its program requests.

13.8 Safety Culture

SCE recommends that SCE continue to develop its safety culture program initiatives, and that SCE retain a core set of permanent unchanging questions in its safety culture assessment surveys.

13.9 Craft Close Call Reporting System

SED recommends that the Safety Reporting/Close Call program be broadened and funded to include, as appropriate:

- Expansion to all worker classifications
- Root Cause Analysis
- Corrective Actions
- A process, or root cause analysis, to use safety reports to then revise or develop new programs, procedures, and training
- A process, or root cause analysis, to use safety reports to then revise or develop new designs, safeguards, and procurement.

APPENDIX A

POLE LOADING RISK ASSESSMENT METHODOLOGIES DEFICIENCIES

1.1 POLE LOADING REPLACEMENT PROGRAM

As described by SCE in its Test Year (TY) 2018 GRC application, the Pole Loading Program (PLP) is an assessment and remediation program, incremental to the Deteriorated Pole Replacement & Restoration Program, that identifies poles for repair or replacement that do not meet pole loading safety factor requirements of General Order (G.O) 95 and SCE's internal design standards, including wind loading in high wind areas of SCE's service territory.[1]

The utility's Distribution & SubTransmission wood poles have been identified as assets with a substantial safety risk component, ranking third among the utility's scored risks, and first in requested mitigation spending of approximately $386 million for capital and $5.47 million O&M for TY 2018[2]. Specifically, SCE's CPUC-Jurisdictional Pole Loading related capital requests are roughly $150 million for TY 2018.[3] In determining a 1-year Current Residual Risk (CRR) Score, nearly half of the risk was attributed to safety (509,892/1,097,224). This CRR Score does not distinguish between risks for separate wood pole programs, which means SCE did not provide a discrete CRR score for its Pole Loading Program separate from its Deteriorated Pole Replacement & Restoration Program or any other wood pole program. Hence, it is not possible to relate to this CRR score specifically to the Pole Loading Program.

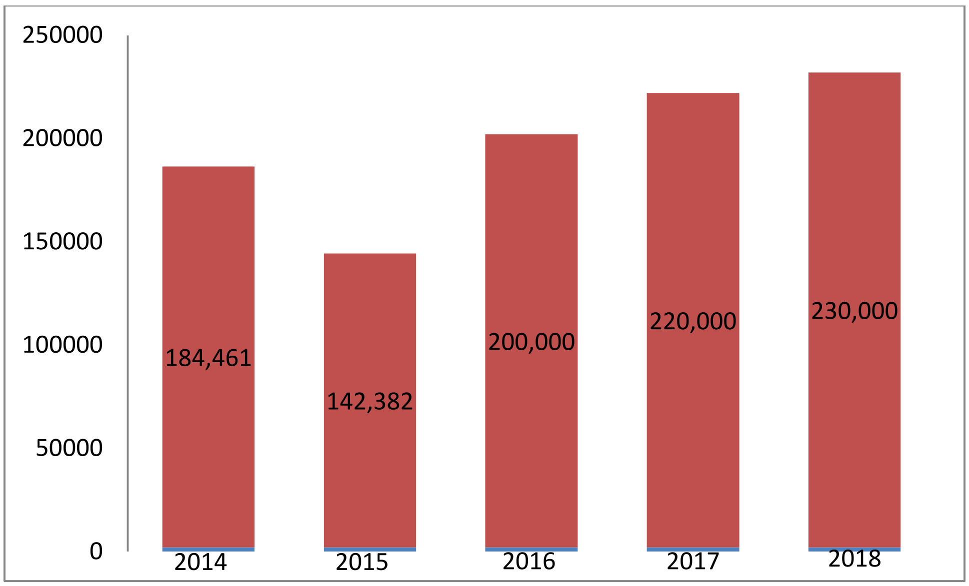
Table 1 SCE 2018 Poles Replacement GRC Request[4]

SCE Poles Capital Request 2018 (Nominal $000)	
	2018
Pole Loading Distribution Pole Replacements	$119,731
Pole Loading Transmission Pole Replacements	$24,628
Distribution Deteriorated Pole Replacement & Restoration	$177,355
Transmission Deteriorated Pole Replacement & Restoration	$64,362
Total	**$386,076**

[1] SCE-02, Volume 9, page 1
[2] SED Risk and Safety Aspects of SCE's 2018-2020 GRC Report Table 9
[3] SCE-02, Volume 9, Table I-4, page 7.
[4] SCE-02, Volume 9, Table I-3, page 6

In testimony, SCE presented a table showing that SCE recorded 184,461 and 142,382 pole loading assessments in 2014 and 2015, respectively[5]. SCE forecasts 200,000 assessments in 2016, 220,000 assessments in 2017 and 230,000 assessment in Test Year 2018. SCE staff stated that they started with high fire and high wind areas as they had suggested in the 2015 GRC application.[6]

Table 1: Pole Loading Assessments (Recorded & Forecasted)



1.2 Main Identified Deficiencies

SED has discovered the following deficiencies with SCE's pole loading risk assessment methodology:

- TY 2018 pole loading study sample[7] is not a statistically valid random sample;
- TY 2018 and TY 2015 pole loading studies' failure rates cannot be directly compared and any comparisons are inconclusive since the studies have different cohorts;
- SCE's third-party pole loading assessment SPIDACalc software[8] has not been independently verified and validated[9] to test the results provided by the specific

[5] SCE-02 Vol.09 page 19 Table II-7, Pole Loading Program Assessments.
[6] SED believes the percentage of assessments in 2014 and 2015 in high wind area and high fire areas would be important information to further request. This would include whether "AND" means that the poles would meet both criteria and any potential high fire area requirements from the Commission's Fire Map rulemaking.
[7] SCE-02, Volume 9, page 15, and WP SCE-02, Vol. 09, pp. 86-87.

software version utilized for SCE's electrical distribution and transmission wood pole design. This would include modeling telecommunications utilities and other typical Joint Pole Owners (JPO) and renter facilities' and utilizing typical SCE pole structure configurations for its service territory. This also includes utilizing appropriate design criteria (i.e. safety factors, etc.) required by G.O. 95 Overhead Line Construction Section IV, Strength Requirements for All Classes of Lines;

- SCE did not assess risk separately for varying levels of pole loading risks (i.e. SCE did not provide different failure rates for very high risk poles versus high risk poles versus medium risk poles, etc.) making it impossible to identify which modeling and design criteria requirements are attributed to addressing various risk levels. This includes not being able to distinguish failure rates attributable to G.O. 95 safety factor and other requirements compared to SCE's internal more stringent design requirements and how various applicability of SCE's requirements are related to various high levels of risk areas.

The following section detailing background of the origin of the Pole Loading Program is critical to understanding why the requested pole replacement program changed significantly, from what SCE requested in its 2015 GRC (i.e. 19% of 1.4 million distribution and transmission poles) to the current forecasted pole replacement rate of 8.6% in SCE's 2018 GRC application and why SED focused on evaluating SCE's 2018 pole loading assessment methodology.

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[8] Per SPIDA Software's website, SPIDACalc's Structure Analysis Software utilizes the latest software technology and a geometric non-linear finite element analysis engine to drive pole loading, pole strength, and guying analysis to power clearance evaluations and structural calculations. Reference: http://spidasoftware.com/products/spidacalc_pole_loading/ (1/25/17).

[9] Independent software verification and validation, per Wikipedia, is the process of checking that a software system meets specifications and that it fulfills its intended purpose, carried out by a separate group from the development team. https://en.wikipedia.org/wiki/Software_verification_and_validation (1/27/2017).

1.3 Background

1.3.1 CPUC's Decision for SCE 2012 GRC Regarding Pole Loading

In the CPUC's decision for SCE's 2012 GRC,[10] the Commission expressed concern about safety issues related to pole loading when considering SCE's request for authorization for its Wood Pole Intrusive Inspection Program. Essentially, the Commission stated that it did not believe SCE had adequately shown why it should be fully funded for the deteriorated wood pole intrusive inspection program. Partly due to the Commission's concern about the additional impact of pole loading issues, the Commission decided to fully fund SCE's deteriorated pole program request.[11] However, the Commission also ordered SCE to "perform full inspections of a statistically valid random sample of loaded poles, utility-owned and jointly-owned, to determine whether the loads meet current legal standards."[12]

The Commission included an additional requirement in Subsection (1) of the same ordering paragraph of that decision: "To the extent that the Commission orders, through any other proceeding, an examination of pole loads within SCE's territory, the study ordered here shall be coordinated to avoid duplication."[13]

The Commission required SCE to serve the summary results of the study on the service lists of that proceeding and Rulemaking 08-11-005, and provide the pole-by-pole results to the Director of Consumer Protection and Safety Division[14], no later than July 31, 2013. The Commission also required SCE to include the results with SCE's next Distribution Inspection and Maintenance Plan annual report.[15] The Commission also ordered: "Following receipt of the pole load study results, the Director of Consumer Protection and Safety Division shall make recommendations to the Commission about what steps, if any, are necessary to assure that Southern California Edison Company's poles are not overloaded going forward."[16]

[10] D.12-11-051, pages 180-181
[11] D.12-11-051, page 181
[12] D.12-11-051, OP 17 and SCE-02, Vol. 09, Workpapers p.90
[13] *Id.*
[14] The CPUC Safety & Enforcement Division encompasses the relevant roles and responsibilities of the former CPUC Consumer Protection and Safety Division.
[15] *Id.*
[16] D.12-11-051, OP 18

1.3.2 SCE's July 2013 Pole Loading Study

SCE stated in its 2013 Pole Loading Study[17] "In SCE's 2012 General Rate Case Decision (D.12-11-051), the California Public Utilities Commission ("CPUC" or "Commission") directed SCE to perform a statistically valid sample of both utility and jointly owned poles to determine whether the loads meet current standards. SCE stated they hired an independent contractor, IJUS LLC, to perform field inspections and complete a pole loading analysis on a statistically valid random sampling of utility-owned and jointly-owned poles throughout SCE's service territory.[18]

SCE explained pole loading calculations are performed when a new pole is installed or when equipment is added to a pole that materially increases the load on the pole. SCE stated that for jointly owned poles, it is the responsibility of the attaching utility to perform the pole load calculations. SCE stated that over time, changes in design standards and technology as well as differences in methodology among the joint pole owners have resulted in poles that may have met the G.O. 95 safety factor requirements when installed, but when measured under today's conditions are no longer compliant. SCE pointed out that it had proposed a Pole Loading Program designed to address these issues and referenced SCE's 2015 GRC NOI, tendered July 15, 2013, SCE-03, Vol. 6, Part 2, Pole Loading Program.[19]

SCE stated that in some cases, SCE standards exceed the minimum design standards set forth in G.O. 95. SCE provided an example of previously designated high wind areas based upon past incident occurrences and wind speed observations. SCE stated these designations are consistent with the intent of G.O. 95, Rule 31.1, as amended in January 2012, which requires utilities to apply standards greater than the requirements in G.O. 95, when necessary, in consideration of known local conditions. SCE also noted that it was currently in the process of updating its high wind designations based upon a study currently being conducted by REAX Engineering.[20]

SCE stated that for the purposes of the 2013 Pole Loading Study, every pole was assessed against SCE's current standards, which may exceed standards of G.O. 95, or in some cases the lower standards that might have applied when the pole was installed. That is, SCE did not

[17] SCE-02, Vol. 09 Workpapers pages 88-104
[18] *Id.,* p. 95
[19] *Id.,* p. 95 and Footnote 3
[20] *Id.,* p. 96 and Footnote 4

"grandfather" poles that had been installed under less stringent criteria in effect at the time of installation. SCE stated this decision was consistent with SCE's current intent to upgrade all poles that do not meet current design standards. At the same time SCE did not concede that all poles (or any particular pole) showing failing safety factors in the 2013 Pole Loading Study are in violation of G.O. 95 or other rules or regulations.[21]

In February 2013, SCE stated IJUS began gathering information and performing pole loading calculations on 5,006 SCE and jointly-owned poles. SCE stated the pole loading analysis evaluated bending, vertical or buckling, and guying requirements for each structure. SCE stated upon performing the pole load study, SCE was able to determine that 3,891 of the 5,006 poles evaluated, or 77.7% met or exceeded SCE's current design standards.[22]

1.3.2.1 SCE's 2013 Pole Loading Study Sampling Plan

SCE stated the sampling was designed to evaluate and estimate, with a 95% confidence interval, the proportion of SCE's 1,423,101 non-engineered distribution and transmission poles that meet SCE's current pole loading criteria using modern measurement and analysis techniques.[23] SCE stated that for appropriate conclusions to be drawn from the sampling results, both the differences in expected outcome and population sizes among the regions were considered in designing the sample. SCE stated due to geographical differences in SCE's service territory, the sample was stratified into 8 groups. SCE stated to obtain the 95% confidence interval, the plan required sampling approximately 3,000 poles across their service territory. SCE stated they augmented this sample size to include approximately 2,000 additional poles, and assigned poles to each stratum such that a minimum of 10 poles were assessed from each stratum. SCE stated they divided the sample size within each stratum among various SCE districts such that nearly all of SCE's districts would be represented in the study. SCE stated that once they determined the number of poles to be sampled for a combination of stratum and district, poles were selected randomly from the corresponding population.[24]

[21] *Id.,* p. 96 and Footnote 6
[22] *Id.,* pp. 96-97
[23] *Id.,* p. 95 and p. 97
[24] *Id.,* p. 97. See Table 1: Stratified Sampling Plan – Population and Sample Size by Sampling Strata for more details.

1.3.2.2 SCE's 2013 Pole Loading Calculations & Design Standards & Technology

SCE explained that pole loading calculations require many inputs, including but not limited to[25]:

- Pole class (size), length, wood species, and ground line circumference;
- Height, number, size, weight, type, angle, and span length of attached conductor and equipment;
- The height, number, and lead length of guy wires supporting the pole and its attachments, including cables, messenger wires, antennas and risers, to the extent third-party information is available or can be measured in the field. (See G.O. 95, Appendix F)

SCE stated that over time, design standards and pole loading technology have evolved. SCE stated that at that time, SCE utilized software tools to evaluate pole loading requirements and calculate safety factors, as specified in Appendix F of G.O. 95. SCE stated the tool used by IJUS in the 2013 pole loading study, SPIDACalc, was the tool currently used by SCE. SCE stated the software tool calculates precise safety factors along with entire length of the pole, something that is not practical using hand calculations or earlier software tools. SCE stated as required by G.O. 95, Grade A wood poles (joint use) must meet an "in-service" safety factor of 2.67; and Grade B wood poles (SCE only) must meet an "in-service" safety factor of 2.0. SCE stated the pole loading study included 4,968 wood poles, 30 light weight steel poles and 8 composite fiberglass poles for a total of 5,006 poles.[26]

SCE also explained that engineered steel poles were not within the scope of the study, but 30 light-weight steel poles (LWSP) were included in the sample. SCE stated it uses a minimum safety factor for LWSP that exceeds the G.O. 95 minimum safety factors contained in G.O. 95 Rule 44.1 in the ordinary course of business; thus, SCE used its higher design standard in the 2013 pole loading study.[27] SCE also explained that the sample included 8 composite fiberglass poles and similar to LWSP, SCE's requirements for those poles exceed the minimum safety factors specified in G.O. 95, Rule 44.1 for Other Structural Materials.[28]

[25] *Id.,* p. 98 and Footnote 7
[26] *Id.,* pp. 98-99
[27] *Id.,* p. 100 See Tables 3 & 4 for comparisons of SCE LWSP Safety Factors versus GO 95 safety factors
[28] *Id.,* pp. 100-101 See Table 5 & 6 for comparisons of SCE Composite Poles Safety Factors versus GO 95

1.3.2.3 SCE's 2013 Pole Loading Study Results

SCE stated that its results reflected the pole loading safety factor criteria for the overall rate of poles passing and failing in the sample population. 929 poles [assessed], or 18.6% of the total sample, failed the first criteria of bending safety factor. Of the remaining poles that passed the bending criteria, 25 poles [assessed], or less than 0.5% of the total sample, failed the vertical safety factor; and of the remaining poles that passed both bending and vertical loading, 161 poles [assessed], or 3.2% of the total sample, had at least one or more guy wires that failed the guy safety factor.[29]

1.3.3 SED's November 2013 Letter Regarding SCE's 2013 Pole Loading Study[30]

In SED's November 7, 2013, letter responding to D.12-11-051 Ordering Paragraph 17 and 18, SED staff stated that in its opinion the loading study that SCE submitted on July 31, 2013, adequately met the requirements of the ordering paragraph of the Decision. At that time, SED did not have the resources to assess the pole loading assessment methodology (i.e. SPIDACalc) and relied upon SCE's 2013 Pole Loading Study results provided to SED.

SED staff clearly recommended on page 2 of its letter that: "SCE's analysis should prioritize poles utilizing a risk management program. The risk management program should consider at least the following factors:

a. Whether the pole is in a High Fire Threat Area.
b. The number and effect of communication facilities attached to the pole.
c. The failure rate of the poles in the area, based upon the loading study.

1.3.4 CPUC's Decision for SCE 2015 GRC Regarding New Pole Loading Program

In its TY 2015 GRC application, the utility requested a new Pole Loading Program driven by what SCE claimed to be significant projected failure risks for approximately 22% of its total 1.4 million poles.[31] SCE stated its potential risks assessments were largely driven by use of a new computer software tool, called SPIDACalc.

Again, "pole loading" refers to the calculation of whether a pole meets certain design criteria called "safety factors" based on wind in that location and facilities attached to the pole. G.O. 95

[29] *Id.,* p. 102
[30] SCE-02, Vol. 09, Workpapers pages124-126
[31] A.13-11-003, SCE 2015 GRC, SCE-15, Supplemental Testimony, pages 24-25.

establishes pole loading safety factors for California utilities. Pole loading calculations consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys.[32]

The final decision in the 2015 GRC authorized SCE's proposed pole loading assessment plan and found that "the public interest in quickly developing a more comprehensive understanding of the extent of the overloaded poles outweighs the potential cost deferral advantage of slowing the pace of assessments."[33]

In reaching the decision, the Commission relied on what it considered a "few seminal facts" that were not disputed:[34]

- A significant fraction, nearly 19%, of poles reviewed in SCE's PLP study are overloaded, and specifically failed the bending analysis. The study suggested similar failure rates in SCE's total population of poles. SCE proposed to replace these poles.
- An additional 3% of poles in the study are overloaded and could be repaired through addition or repair of guy wires. Again, the study suggested a similar rate in the total pole population. SCE proposed to repair these poles.
- Overloaded poles present a significant safety hazard and reliability risk.

Based on these and other findings, the CPUC agreed with parties that some form of PLP should be authorized. However, the CPUC did not conclude that SCE had adequately justified its specific proposal.[35]

The CPUC approved approximately 73% of SCE's PLP replacement pole proposal for TY 2015, and it stated SCE must apply for approval of 2016 and later years' PLP capital expenditures in the TY 2018 GRC. The CPUC directed SCE to focus on its early PLP efforts on high hazard areas, considering hazard maps developed in R.15-05-006 and other relevant information.[36] The CPUC also found that PLP assessments should provide factual information

[32] D.15-11-021, Section 7.7, Pole Loading.
[33] D.15-11-021, Section 7.7.2.1, Assessments and Planning (Distribution and Transmission).
[34] D.15-11-021, Section 7.7.3.1.3, [Pole Replacements] Discussion and Findings of Facts (FOFs) Nos. 144-146.
[35] D.15-11-021, Section 7.7.3.1.3, page 135.
[36] D.15-11-021, pages 141-142.

about the extent to which attachments contribute to any valid safety or reliability concerns and potentially non-compliance with G.O. 95 standards.[37]

1.4 SCE's Discovery of Substantive Problem Before 2015 GRC Decision

In April 2013, SCE began using SPIDACalc as the enterprise-wide tool to calculate pole loading safety factors for its poles.[38] Also in 2013, SCE engaged an experienced meteorological engineering firm to perform a system-wide wind study based on a scientific evaluation of historical wind events. SCE states the result of this wind study is that SCE added a new 24 pounds per square foot wind loading specification in certain areas and the wind loading criteria in many other areas was increased. SCE states the revised wind loadings were implemented in March 2014.[39]

In parallel to the timeline of SCE's 2015 GRC application before the Commission, SCE states its planners in 2014 noted that sometimes SPIDACalc called for larger pole sizes than planners were anticipating to meet minimum safety factor requirements. Due to the March 2014 updated higher wind loading specifications, SCE stated it found it difficult to isolate the impact due to the use of SPIDA. Yet, in July 2014, SCE stated its engineers began to evaluate how SPIDACalc handled the design situations in which these results were obtained.[40] In December 2014, the evaluation determined that SPIDACalc calculated a lower safety factor in some of the analyzed poles examined when benchmarked against the full engineering version of PLS-CADD. SCE states these results reflected conservative assumptions of the software.[41] As early as December 2014, SCE engineering identified some potential improvement areas in SPIDACalc's safety factor calculation methodology to increase its accuracy while maintaining compliance with G.O 95 safety factors and SCE internal pole loading standards.[42]

SCE states in April 2015, a test version of SPIDACalc was provided for re-evaluation of the poles used in the initial engineering study. SCE Engineering determined that the software still required additional development to correctly model what are called dynamic wire tensions.

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[37] D.15-11-021, FOF 151.
[38] SCE-02, Vol. 09, page 11
[39] *Id.,* page 1
[40] *Id.,* page 13
[41] *Id.*
[42] *Id.*

Additionally, SCE states the database of equipment characteristics used to build models, called a "client file", was updated to improve the accuracy of equipment characteristics represented in the models. In May 2015, the initial delivery of dynamic wire tensions for the most common SCE conductors were provided to the SPIDA company, and work began on compiling dynamic tension values for telecom and cable TV spans.[43] SCE states it worked with the software provider to develop the scope of the improvements, which were first incorporated into the SPIDACalc software in May 2015.[44]

SCE states two improvements were incorporated in SPIDACalc Version 6.0, which released on May 21, 2015, to more accurately model the effect of wire tension on the pole. However, SCE states the dynamic tension data for communication company wires and some SCE wires was not yet complete, so these improvements could not yet be used in the production version of the software. SCE states the majority of the data was compiled and provided to SPIDA in June 2015. The data was also provided to SCE's assessment vendor so that they could determine the level of effort required to adopt the new client file.[45]

SCE states that in July 2015 testing of the software determined that reject rates would drop when the new version was deployed. Accordingly, in August 2015, SCE performed an assessment of approximately 1,400 poles, which suggested that reject rates with the new software and client file may be approximately 9%. SCE states it sought to balance the benefit of lower remediation rates against the risk of delaying the identification and remediation of poles with noncompliant safety factors, and impeding the design process and delaying other maintenance and infrastructure replacement work that required a pole loading assessment. [46]

SCE states SPIDACalc assessments were necessary not only for the PLP program, but for any maintenance or infrastructure replacement activity in any program that would materially impact the load on a pole. For these reasons, SCE decided on August 8, 2015, to delay implementation of the client file until performance issues could be addressed.[47]

[43] *Id.,* page 14
[44] *Id.,* page 11
[45] *Id.,* pages 14-15
[46] *Id.,* page 15. SED considers client file to include SCE's design criteria from its design standards including G.O. 95 requirements and its own internal design standards.
[47] *Id.,* page 15

SCE states final dynamic tension data was delivered to SPIDA early August 2015. SCE states SPIDA then configured the data so that it could be used in SPIDACalc, and then provided the configured data to the assessment vendor so that the assessment vendor could make necessary updates in its systems. SCE states an improved version of SPIDACalc which addressed these issues was approved on October 27, 2015, and became effective November 19, 2015.[48] SCE states the changes enabled SPIDACalc to more accurately model poles in the field, and as a result significantly reduced the rate at which poles fail pole loading calculations.[49]

Hence, even before the Commission rendered a decision in the 2015 GRC, SCE was aware of a substantive problem with their pole loading assessment software (i.e. SPIDACalc) as early as December 2014. Also, SCE became aware of their “client file” or design criteria problems in the spring of 2015. SCE stated it saw a significant increase in the failure rate, from what SCE has forecasted, in the third quarter of 2015 and determined they needed to stop to evaluate SPIDACalc and their own client file further. SCE explained that the results from the pole loading assessments were not consistent with what SCE observed in the field. Therefore, SCE stopped 40,000 replacement poles that were in prefabrication production in September 2015.[50] SCE admitted that it did not inform the Commission of this significant finding until it briefed the Safety & Enforcement Division’s Electric Safety & Reliability Branch staff on April 19, 2016, as it was preparing its testimony for the TY 2018 GRC application filing.

SED concludes that although SCE states there have been notable enhancements in their pole programs since the 2015 GRC[51], these previous deficiencies in SCE’s third-party SPIDACalc software and SCE’s “client file” create **low confidence** in SCE’s current pole loading assessment methodology.

Even with the passage of time, it is troubling that SCE did not inform the Commission of this significant issue during the Commission’s 2015 GRC proceeding.

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[48] *Id.,* page 15
[49] *Id.,* page 11
[50] Ms. Menon & Mr. McHale, 12/30/2016 phone meeting, stated that SCE saw an increased failure rate in the third quarter of 2015 and determined they needed to stop to assess the previous version. This was also discussed at the April 19,2016 SCE Briefing to SED staff on SCE 2018 GRC Poles and in SCE’s 11/2/2016 SCE 2018 GRC “Deep Dive on SCE Testimony on Poles” in this proceeding.
[51] SCE-02, Vol. 09, page 1

1.5 Lack of Statistically Valid Random Sample & Lack of Valid Comparisons

SED does not have detailed information needed for the 31 projects including 1,400+ poles to assess whether and how SCE may have scrutinized their "Client File", which includes "design characteristics" that provided and decided upon by SCE.

SED reviewed SCE's 2013 Pole Loading Study "pole-by-pole" results provided in a MS Excel spreadsheet to Commission staff as a confidential DR response in the SCE 2015 GRC. The 5,006 poles in SCE's 2013 Pole Loading Study included approximately 3,000 poles that SCE states were a random sample with an additional approximately 2,000 poles identified as "supplemental" poles. SCE stated "To obtain the 95% confidence interval, the plan required sampling approximately 3,000 poles across our service territory."[52]

Staff inquired repeatedly why the same pole sampling for the 2013 study was not utilized for the new more recent pole loading analysis. SCE staff had differing responses including at first that the new 1,432 poles selected were a "more representative sample"[53]. Another SCE staff stated that the 1,432 poles were selected differently as there were 31 projects with varying amounts of poles in each project. SCE staff stated one example of a project could be a wind load case. SCE informed SED that the approximately 1,400 poles that were assessed for this 2018 GRC requests, were not the same poles as the 2013 poles which were used for the 2015 GRC requests.

SCE staff did confirm that the number of poles and the poles selected do not represent a statistically valid random sample.[54] SED concludes that there is no way to do an "apples-to-apples" comparison between the previous pole loading assessment methodology and the new revised methodology.

1.6 Additional Detail on SpidaCalc & Client File Issues

SCE stated "several improvements to the software have been made to improve the accuracy of pole loading calculations performed in these configurations as summarized in the

[52] SCE-02, Vol. 09, Workpapers page 97
[53] Ms. Fanous, 12/15/2016 at SCE Pomona Office.
[54] Ms. Menon & Mr. McHale during 12/30/2016 phone meeting.

table copied below[55]. These include the integration of geometric nonlinear modeling with displacement-based loading, the use of dynamic wire tensions, and the inclusion of wire tension data needed to support the new methodology. SCE shows in the table that the SPIDACalc change "geometric nonlinear modeling with displacement-based loading methodology" enabled improved modeling of loads and tensions. SCE shows in the table that the SPIDACalc change "static wire tensions" to "dynamic wire tensions" was required for new methodology to function properly. SCE shows in the table that the SPIDACalc change to the "Client File" to include additional/updated wire tension and equipment data supported new wire tensions and enabled new methodology.[56]

Table 2 SPIDACalc program changes

Table 1:
Summary of SPIDACalc Changes Impacting Remediation rates

	Change	Impact
Methodology	Geometric Nonlinear Model w/ Displacement Based Loading	Enabled improved modeling of loads and tensions
Wire Tensions	Changed from static to dynamic tensions	Required for new methodology to function properly
Client File	Additional / updated wire tension and equipment data	Supports new wire tensions, and enables new methodology

The workpapers explain that wire tension modeling, used as part of the safety factor calculation, was discovered to be inadequate resulting in "loads that are greater than those experienced in practice". The "software packages considered in the RFP" "required a new methodology to function properly" which changed wire tensions to be modeled dynamically rather than statically. SCE also explained that a "related issue was discovered after the selection process with the treatment of tension on guys" resulting in the model estimating "lower safety factors than what the pole experiences" and "higher remediation rates".

[55] SCE-02, Vol.09 WP pages 120-122 for the Technical Summary of SPIDACalc changes.
[56] SCE-02, Vol.09 WP pages 120-122 for the Technical Summary of SPIDACalc changes.

SED points out that although many of these items are related to the SPIDACalc changes, some of these items are actually related to SCE's changes to its own "client file" or design criteria. Specifically, the change to SCE's wire tension and equipment data was necessary to address inaccurate failure rate calculations by SPIDACalc even once SPIDACalc was revised.

This finding was became clearer to SED, after contact was made to SPIDAWeb LLC (owner of SPIDACalc) directly by email and phone during the last week of December 2016. During a phone call, a SPIDAWeb representative made clear that SCE had also refined its own "client file" data in order to do more accurate pole loading assessment modeling.

SPIDAWeb also shared the "Third-Party Verification of SPIDACalc Software for Non-Linear Analysis of Distribution Poles" dated 7/11/2016 conducted by CIMA+, a Canadian professional engineering firm.[57] SED reviewed the entire 10-page report, along with some appendices that SCE has marked as confidential.[58] SED discovered that the 3rd party verification was by Canadian licensed professional engineers with the expressed purpose "to analyze and test the results provided by SPIDACalc software (version 6.3.0.0) for electrical distribution pole design and analysis, as per the requirements of the CSA C22.3 No. 1-15,[59] using typical pole configurations used in Ontario, Canada".[60]

SED also discovered that the "eight (8) models studied" were "based on standard 15kV 3-phase wood pole framings used in the province of Ontario, Canada". SED also found that the professional Canadian engineers "verified SPIDACalc's non-linear analysis" by utilizing the "eight different typical distribution structures" and modeled them "in SPIDACalc, PLS-POLE (version 14.00), and in some cases, S-FRAME (version 11.00.22) non-linear finite element software."[61]

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[57] SED obtained CIMA+ main report (without appendices) directly from SPIDAWeb LLC without signing a Non-Disclosure Agreement (NDA) as SED currently has licenses for SPIDACalc software. SCE provided this same Report as a SED DR Response but marked it confidential.

[58] SED obtained these appendices exclusively in an SCE Confidential DR Response. Our analysis draws from the non-confidential version provided by the vendor.

[59] http://www.techstreet.com/standards/csa-c22-3-no-1-15?product_id=1898715 SED downloaded the "Preview" which included the first cover sheets and the first 14 pages of the standard including the Table of Contents. CSA stands for Canadian Standards Association.

[60] CIMA+ "Third-Party Verification of SPIDACalc Software for Non-Linear Analysis of Distribution Poles" page 1

[61] *Id.,* page 2

SCE's T&D Director recounted that when SCE issued a solicitation for pole loading software in 2013, there were three responses including: PLS-CADD, SPIDACalc, and O-Calc (Osmose). SCE's T&D Director stated that PLS-CADD was the better engineering software but SPIDACalc was chosen because it was much more user-friendly for large number of assessments. SED also has knowledge that PG&E utilizes O-Calc and PacifiCorp utilizes PLS-CADD. PLS-POLE is a subset of PLS-CADD as can be found on Power Line Systems (PLS) Inc. website.[62]

As stated in the report, "PLS-POLE is a software tool specifically tailored for the design of structures made up of wood, laminated wood, steel, concrete or fiber reinforced polymer (FRP) poles, which has been verified to accurately perform a geometric non-linear analysis. S-FRAME is a well-established general structural analysis software tool."

SED finds the third-party verification report by CIMA is only applicable for Canadian requirements for Canada's electrical standard "CSA C22.3 No.1-15. It does not apply to G.O. 95 or U.S. National Electrical Safety Code (NESC) requirements. Although the purpose of the CIMA study was to analyze and test the results provided by SPIDACalc software (version 6.3.0.0) for electrical distribution pole design and analysis, as per the requirements of the CSA C22.3 No.1-15, using typical pole configurations used in Ontario, Canada, it does not use typical pole configuration for SCE's territory nor does it include any subtransmission pole models.

SED believes the Canadian 3rd party verification report is not adequate to verify and validate SPIDACalc' pole loading assessment results for G.O. 95 safety factor and other G.O. 95 requirements or to meet SCE's own internal standards for its distribution and transmission poles.

1.7 Lack of Differentiated Failure Rates For Various At-Risk Poles

SCE did not assess risk separately for varying levels of pole loading risks (i.e. SCE did not provide different failure rates for very high risk poles versus high risk poles versus medium risk poles, etc.) making it impossible to identify which modeling and design criteria requirements are attributed to addressing various risk levels. This includes not being able to distinguish failure rates attributable to G.O. 95 safety factor and other requirements compared to SCE's internal more stringent design requirements and how various applicability of SCE's requirements are

[62] http://www.powline.com/products.html

related to various high levels of risk areas. As SCE recommended in November 2013, the risk management program should minimally address the failure rate of the poles in the area, based upon the loading study.

1.8 Additional Concerns & Thoughts

SED is concerned as it is unclear whether SCE will continue to revise its methodology including SPIDACalc revisions and its own design criteria to result in potentially significant pole loading assessment results. SED is concerned that both the number of poles to be replaced or repaired could significantly continue to change and which poles are found to need to be replaced or repaired.

SED is also unclear how the recently revised G.O. 95 with very high fire areas or the Fire Mapping rulemaking where high fire areas are being additionally defined overlap SCE's design criteria for high fire areas and separate wind criteria. SCE identified pole loading risks as potentially leading to wildfire but it is unclear whether high wind design criteria (i.e. above G.O. 95 requirements) should be included in the pole loading assessment methodology if poles are not located in high fire areas.

SED believes it would be beneficial for SCE to be more transparent about the Client File and design characteristics for the SPIDACalc pole loading analysis, and should confer with SED RASA engineers, as this design data and assumptions can tremendously impact which poles and the number of poles that fail loading assessments.[63]

SED does acknowledge SCE's foresight and efforts to advance the industry by supporting the advancement of software development to do pole loading modeling and assessments which could be an innovative development. Yet SED is concerned that any forthcoming assessments utilizing new software and potentially continually changing design criteria could not be adequately managing, mitigating and minimizing safety risks associated with pole loading. Hence, SED also recommends that an independent, appropriately licensed state of California engineering firm evaluate design criteria to ensure that they are adequate to manage, mitigate and

[63] G.O. 95 Rule 44.1 "The entity responsible for performing the loading calculation(s) for an installation or reconstruction shall maintain records of these calculations for the service life of the pole of other structure for which the loading calculation was made and shall provide such information to authorized joint use occupants and the Commission upon request."

minimize safety risks associated with pole loading. At a minimum, engineering analysis is needed to verify SCE's design criteria meet CPUC General Order 95 requirements, with clear identification of design criteria that are beyond G.O. 95 requirements, and the impacts to any pole loading assessments.

1.8.1 Ever Changing Standards

In additional data requests responses, SED requested the last 5 years of standards related to pole loading. SED received multiple megabytes of files with hundreds of pages for each standard. SED observed that from 2011 to 2013, SCE pole loading standards provided were included in their Distribution Design Standards (DDS), updated on a quarterly basis. Then from 2014 onward, SCE provided Pole Loading standards that were also quarterly updates (with the exception of 2014 where only 3 standards were provided.) SED noted that the Pole Loading Standards were hundreds of pages each and sometimes had dozens of pages either added or subtracted in each quarterly update.

This in and of itself makes SED concerned that its design criteria may be rapidly changing and is not in a steady state yet.

1.9 Main Recommendations

SED recommends the Commission require SCE to conduct a pole loading study on a statistically valid sample for SCE's service territory, after conferring with SED Risk Assessment & Safety Advisory engineers, but also after other SED recommendations below are fulfilled.

SED recommends the Commission require SCE to have an independent engineering firm, with appropriately state of California licensed engineers, verify and validate the SPIDACalc software to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, against G.O. 95 Overhead Line Construction safety requirements. At this time, SED believes this type of third-party independent verification and validation study should utilize Power Line Systems Inc. PLS-CADD industry standard for overhead electric power transmission, distribution, and communication lines and structures, along with industry established manual mathematical calculations for bending analysis, etc. SED recommends an appropriate sample selection of SCE distribution and transmission pole types and heights should be utilized for this study.

SED further recommends that the Commission require SCE require that the independent verification & validation (V&V) process model typical telecommunications utilities and other typical JPO and renters' facilities along with typical SCE pole structure configurations for its service territory.

Again, in order to have increased confidence in SCE's assessment of its pole replacement program, SED recommends the Commission require SCE have an independent engineering firm, with appropriately State of California licensed engineers, verify and validate the SPIDACalc software to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole design, against G.O. 95 Overhead Line Construction safety requirements. SED recommends that the Commission require SCE require that the independent verification & validation (V&V) process model typical telecommunications utilities and other typical JPO and renters' facilities along with typical SCE pole structure configurations for its service territory. This V&V process would check the software system to ensure that it meets specifications *and* that it fulfills its intended purpose. Design criteria for typical pole configurations and other facilities should minimally include:

- Loading from ruling spans, other spans, phase and neutral wires, telecommunications cables, weather conditions, and overload factors;
- Structure geometry and component properties;
- Detailed geometry of each model analyzed;
- Crossarm properties;
- Conductor/wire properties; and
- Insulator properties.

SED recommends that SCE confer with SED Risk Assessment & Safety Advisory engineers with respect to SCE's internal design criteria utilized beyond G.O. 95 requirements. The reasoning is that the Commission should be fully aware of design criteria that impact risk assessments. This is especially the case for a large pole loading replacement and repair program where the costs could impact ratepayers immensely. The proposed program may not necessarily be addressing the greatest safety risks nor the most cost-effective mitigation measures for the utility given the amount of ratepayer funds required. Hence, SED also believes it may be prudent that the same or a different independent V&V firm evaluate SCE's internal design criteria to evaluate specifics on how SCE's internal design criteria or "client file" appropriately manage, mitigate and minimize safety risks associated with pole loading and at a minimum, meet

G.O. 95 safety requirements. Finally, SCE could further improve confidence in its pole loading assessment methodology by conducting and submitting root cause analysis on actual pole failures.

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