(U 338-E)

I.18-11-006

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Rosemead CA

November 15, 2018

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SOUTHERN CALIFORNIA
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Southern California Edison Company's

Risk Assessment and Mitigation Phase

RAMP Overview

Chapter 1

Rosemead CA
November 15, 2018

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A. Executive Summary

SCE appreciates the opportunity to present its RAMP report to the Commission and to the Parties in the RAMP Order Instituting Investigation proceeding (I.18-11-006). This RAMP report marks a significant milestone in the progress of SCE's risk-informed decision-making framework, consistent with the evolution of the framework that has been developing in the Safety Model Assessment Proceeding (S-MAP). In preparing this report, we obtained information and support from the majority of organizational units within SCE. We also incorporated feedback we obtained through informal and collaborative discussions with external parties and stakeholders.[1]

Our RAMP report examines the top safety risks to our customers and the communities we are privileged to serve, to our company, and to our employees and contractors.[2] After rigorous analysis and evaluation, SCE identified these nine top safety risks that warranted inclusion in RAMP: *Building Safety; Contact With Energized Equipment; Cyber Attack; Employee, Contractor, and Public Safety; Hydro Asset Safety; Physical Security; Wildfire; Underground Equipment Failure; and Climate Change*.

Each of these nine risks is explained and assessed in detail in the individual chapters of this report. We analyze existing controls, and identify new mitigations that can and will help address these risks. For each mitigation plan, we also present two separate alternative mitigation plans that we considered. We outline why, out of the three plans, we chose the mitigation plan we have selected.

We also deployed a new multi-attribute probabilistic risk evaluation model to evaluate these risks and the effectiveness of their associated controls and mitigations. The attributes

[1] While developing this RAMP report, SCE met with stakeholders on many occasions to discuss our approach to RAMP and solicit feedback. These stakeholders included: the Commission's Safety & Enforcement Division (SED), Office of the Safety Advocate (OSA), Public Advocates Office, Energy Division, and The Utility Reform Network (TURN). We very much appreciate the feedback we received from these stakeholders, and we have included certain feedback as applicable in this report.
[2] Throughout this report, SCE collectively refers to our employees and contractors as "workers."

examined include serious injury, fatality, reliability, and financial. In developing our report, SCE tested several new risk modeling parameters that collectively will advance and illustrate many aspects of the S-MAP Settlement Agreement (Settlement).[3,4] This is SCE's first-generation probabilistic risk evaluation model for use in RAMP, and we expect to refine the model in future RAMP reports.

Finally, we candidly discuss lessons learned, and improvement opportunities for future RAMP reports.

In sum, the RAMP report represents a significant step forward in how we think about, plan for, and mitigate our top safety risks. It will inform the safety-related funding requests that we will include in our Test Year 2021 General Rate Case (GRC), scheduled to be filed by September 3, 2019.

B. Procedural Background

On November 14, 2013, the Commission issued an 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 (R.13-11-006, or Risk OIR). The Risk OIR sought to incorporate a risk-based framework into the Rate Case Plan that each energy utility must follow. In the Risk OIR, the Commission instituted two new processes designed to feed into the portions of General Rate Case applications where utilities request funding for safety-related activities. These two processes are the S-MAP and the RAMP.

SCE's RAMP report originates from, and is guided by, two key Commission decisions. First, in the Risk OIR, the Commission issued D.14-12-025, which modified the Rate Case Plan to include a risk-based framework and "provide a transparent process to ensure that the energy utilities are placing the safety of the public, and of their employees, as a top priority in their respective GRC proceedings."[5] The decision indicated that each utility's RAMP report should show:

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[3] Appendix B to this chapter discusses how the report aligns with this Settlement.
[4] Joint Motion For Approval Of Settlement Agreement Plus Request For Receipt Into The Record Of Previously Served Documents And For Expedited Comment Period Of Pacific Gas And Electric Company (U-39 E), Southern California Edison Company (U-338 E), Southern California Gas Company (U-904 G), San Diego Gas & Electric Company (U-902 M), The Office Of Ratepayer Advocates, The Utility Reform Network, And Energy Producers And Users Coalition And Indicated Shippers; May 2, 2018.
[5] D.14-12-025, p. 35.

- The utility's prioritization of the risks it believes it is facing and a description of the methodology used to determine these risks.

- A description of the controls currently in place, and the "baseline" costs associated with the current controls.

- The utility's prioritization of risk mitigation alternatives, in light of estimated mitigation costs in relation to risk mitigation benefits (a Risk Mitigated to Cost Ratio).

- The utility's risk mitigation plan, including an explanation of how the plan considers: utility financial constraints; execution feasibility; affordability impacts; and any other constraints identified by the utility.

- For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposed plan.[6]

Second, the Commission issued an interim decision in its S-MAP. That interim decision, D.16-08-018, provided certain guidelines for what should be included in the utilities' RAMP reports, including adopting the Cycla Corporation 10-step framework.[7] The decision also guided SED on what it should look for in evaluating the utilities' RAMP submissions and preparing its report on each utility's RAMP showing.

In accordance with the Commission's guidance in D.14-12-025,[8] on August 29, 2018, SCE duly requested an Order Instituting Investigation (OII) to provide a docket for filing of SCE's RAMP showing, as well as comments and feedback on that RAMP. On November 9, 2018 the Commission opened I.18-11-006.

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[6] D.14-12-025, pp. 31-32.
[7] D.16-08-018, Ordering Paragraph (OP) 4.
[8] *See* D.14-12-025, p. 41, Table 3.

C. SCE's RAMP Report Meets Commission Requirements Adopted in the S-MAP Interim Decision[9]

SCE developed this report in accordance with Commission guidance,[10] and with due consideration of feedback received from various stakeholder groups.[11] Our intention is to circulate a transparent and collaborative report that advances utility risk-informed decision-making within the Commission's regulatory process. Our approach to the ten key requirements of the RAMP submission is summarized below:

1. *Requirement 1:* Identify top safety risks

SCE identified nine top safety risk areas. Each one is discussed in individual chapters of this report. Section G of this chapter describes the process we undertook to identify the top safety risks to include in RAMP.

In addition, SCE includes three appendices to this report. Two additional risk areas are addressed in Appendix A – Nuclear Decommissioning Safety Risks, and Appendix B – Transmission & Substation Safety risks. These two areas did not "rise to the top" during the process we followed to identify the top safety risks that would be specifically quantified in this RAMP report. However, after discussion with SED and further internal evaluation, SCE is qualitatively assessing these two areas as a supplement to this report.

The third appendix provides greater context regarding seismic event risk. Seismic events are a key driver to various safety risks for SCE. While major seismic events occur infrequently, such events can seriously impact our critical assets and facilities. SCE must proactively harden our critical assets and facilities to mitigate the safety, reliability, and financial consequences of these events. As will be discussed in greater detail in Section G and in Appendix C, SCE includes seismic events as a driver to both the Hydro Asset Safety and Building Safety chapters.

2. *Requirement 2:* Describe the controls or mitigations currently in place

To describe the controls currently in place, and potential new mitigations, to address each risk, SCE developed three broad groupings of activities: *(1) Compliance Controls,*

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[9] D.16-08-018.
[10] *See* D.14-12-025, D.16-08-018.
[11] As discussed above, while developing this RAMP report, SCE met with stakeholders on many occasions to discuss our approach to RAMP and solicit feedback.

(2) Controls, and (3) Mitigations. This grouping is important in establishing which activities are included in the baseline residual risk, and which activities are measured to reduce that baseline risk.

a. Compliance Controls

Compliance Controls (commonly referred to in the report with the prefix "CM") are defined as currently-established activities that modify or reduce risk, and that are required by law or regulation. To take some examples, activities that support Federal or State OSHA requirements, FERC Orders and requirements for hydro facilities, and Commission General Orders, are all considered Compliance Controls.

In most cases, SCE will include compliance activities in its baseline risk. Because SCE is required to perform these activities by law or regulation, they are foundational to operating the utility. In addition, it is often very difficult to evaluate the inherent risk that is present in the absence of these compliance activities. In each risk chapter, SCE will describe these Compliance Controls and show their recorded expenditures*, but will not evaluate the risk reduction or Risk Spend Efficiently (RSE) of the compliance activities*. Stated differently, the benefits of these compliance activities are included in the baseline risk level for each risk.

b. Controls

Existing controls (commonly referred to in the report with the prefix "C") are mitigation activities established prior to 2018 that are modifying or reducing risk, and are not required by law or regulation. Examples of existing controls include the Overhead Conductor Program, Worst Circuit Rehabilitation program, and internal training programs not associated with a compliance requirement.

In this RAMP report, SCE measures the risk reduction benefits and RSE of existing controls. Section III of each risk chapter details the Compliance Controls and Controls that are currently in place to address each risk.

c. Mitigations

Mitigations (commonly referred to in the report with the prefix "M") are defined as new activities and efforts that reduce risk, and that are not required by law or regulation. Examples of new mitigations include: (1) a new program or project that starts in 2018 or beyond that is not currently being performed; (2) a material incremental scope of work based on emergent risk; and (3) a project or program that is under construction or in the process of being implemented.

In this RAMP report, SCE measures the risk reduction benefits and RSE of new mitigations. SCE identifies and describes these risk mitigations in Section IV of each chapter.

In the workpapers that accompany this report, SCE provides an aggregate listing of the recorded and forecast costs for the proposed controls and mitigations.[12] As appropriate, SCE will refine this list of controls and mitigations in our 2021 GRC, to reflect emergent information on how best to mitigate the RAMP risks.

3. *Requirement 3:* Present a plan for improving the mitigation of each risk

In Section V of each chapter, SCE presents its proposed plan for addressing each risk. This proposed plan pulls together controls and mitigations that were identified in Sections III and IV of each chapter, to develop a preferred risk mitigation portfolio over the 2018-2023 period. We then evaluate this portfolio based on its total cost, risk reduction, risk spend efficiency, execution feasibility, technology maturity, resource constraints, and other factors.

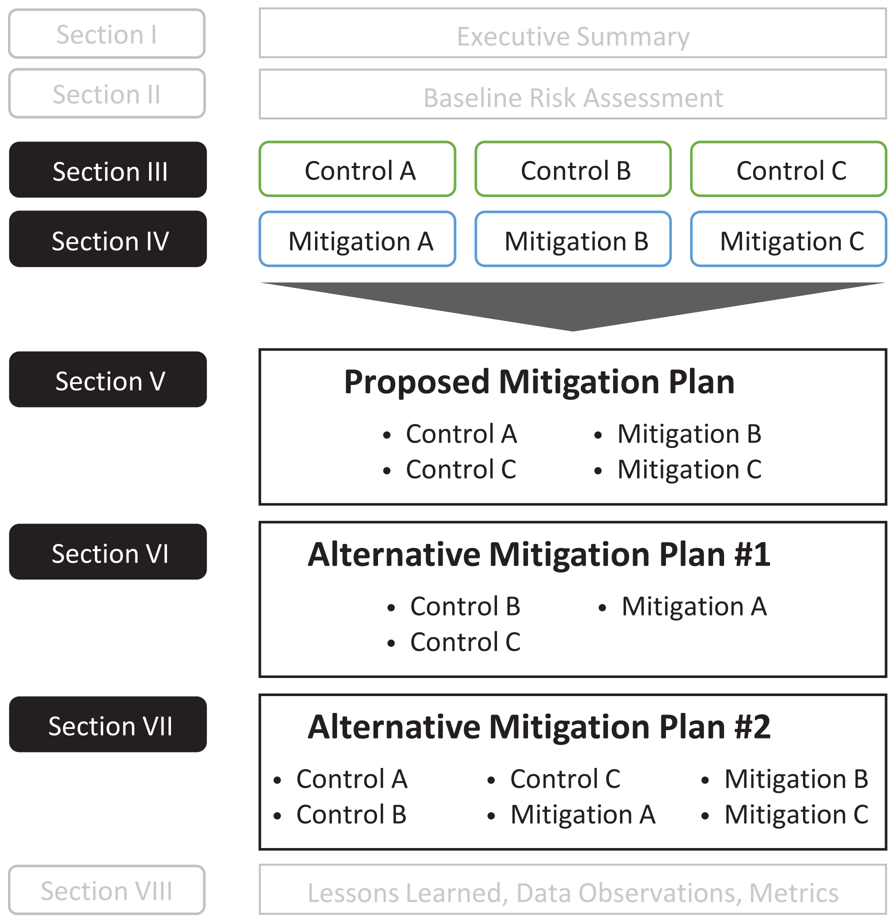
4. *Requirement 4:* Present two alternative mitigation plans that were considered

Finally, in Sections VI and VII of each chapter, SCE details two alternative mitigation portfolios for addressing each risk. Similar to the proposed mitigation portfolio, SCE builds these alternative plans by selecting various controls and mitigations identified in Sections III and IV of each chapter. We also evaluate these portfolios based on total cost, risk reduction, risk spend efficiency, execution feasibility, technology maturity, resource constraints, and other factors.

Figure I-1 illustrates the process SCE uses to identify and evaluate the proposed and alternative mitigation plans within each chapter. The steps in this process (sections II – VII of each chapters) are shown in the broader context of each chapter's structure.

[12] Please refer to WP Ch. 1, p. 1.1 *(2013 – 2023 Recorded and Forecast Costs for Controls & Mitigations)*.

Figure I-1 – Chapter Mitigation Plan Development (Illustrative)



5. *Requirement 5:* Present an early stage "risk mitigated to cost ratio"

SCE has adopted the concept of Risk Spend Efficiency (RSE), which is a measure of risk reduction per dollar spent. In its most simplistic form, the RSE calculation is:

RSE= $(Mitigation\ Risk\ Reduction)/(Mitigation\ Cost)$

SCE applies RSE to individual controls and mitigations over the RAMP period, and to each of the mitigation plans as a whole. The RSE offers us insights into how effective our existing controls appear to be in reducing risk, while providing guidance on how effective the new mitigations may be.[13] We used the RSE as a valuable contributing metric to inform the development of our proposed and alternative portfolios within each chapter. As discussed in each risk chapter, RSE is not the only factor that SCE uses to inform the selection of proposed risk mitigation plans, but it provides directional guidance.

6. *Requirement 6:* Identify lessons learned in the current round to apply in future RAMP reports

Section VIII of each risk chapter identifies lessons learned from developing each chapter that will inform our next RAMP report.

SCE has also identified several global lessons learned across our RAMP effort. These are discussed in more detail in Section J - Global Challenges and Lessons Learned in Development of RAMP Report.

7. Requirement 7: Move toward probabilistic calculations as much as possible

This RAMP report reflects a significant step forward for SCE in using probabilistic modeling to evaluate risk. SCE respectfully believes it has built a robust probabilistic risk modeling framework to support evaluating risk, and examining the effects that risk controls and mitigation activities can have on that risk. To do this, SCE employs a Microsoft Excel-based model that leverages a risk-modeling add-in called @RISK. This model enables us to analyze risk using Monte Carlo simulations,[14] showing us the distribution of virtually all possible outcomes, and how likely they are to occur.[15] This model allows users to insert relevant input data and assumptions in a manner that best reflects the nature of each risk.

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[13] Within this RAMP report, the RSE metric is most useful for relative comparisons between controls and mitigations within a risk chapter. It is important to note that because the maximum MARS score is 100, and because our controls and mitigations cost more than $100 dollars to execute, the RSE scores are all small numbers (mostly less than one). This is purely a product of the RSE math equation, and does not indicate that actual efficiency of a mitigation is low just because the RSE is less than one. *See* Chapter II – Risk Model Overview for further discussion.

[14] Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables. It is a technique used to understand the impact of risk and uncertainty in prediction and forecasting models. Monte Carlo simulation can be used to tackle a range of problems in virtually every field such as finance, engineering, supply chain, and science. Monte Carlo simulation is also referred to as probability simulation.

[15] Please refer to Appendix 2, Section A of this Chapter, and Chapter 2 (Risk Model Overview), for additional discussion on the MARS calculation framework.

8. Requirement 8: For those business areas with less data, improve the collection of data and provide a timeframe for improvement

Section VIII of each chapter identifies data limitations we identified through developing our RAMP showing, identifies opportunities to address those limitations going forward, and outlines performance metrics that will help us measure progress towards reducing the risk.

9. Requirement 9: Describe SCE's safety culture, executive engagement, and compensation policies

Chapter III of this RAMP report discusses SCE's safety culture, safety performance, and how SCE's compensation policies are tied to safety performance.

10. Requirement 10: Respond to immediate or short-term crises outside of the RAMP and GRC process

The environmental, economic, and political conditions in which we operate across our 50,000 square mile service territory are constantly evolving. As the Commission rightly recognizes, we must act expeditiously to address emergent risks that arise outside of the RAMP and GRC processes. SCE's obligation to deliver safe and reliable power requires that adjustments be made as these risks arise. SCE makes these adjustments to our operations on a daily basis to account for contingencies such as major storm events. And these adjustments can be made over a longer period of time to address resources gaps not anticipated in the prior GRC. For example, SCE filed a Grid Safety & Resiliency Program (GS&RP) application[16] in September 2018 to address the very serious and emergent wildfire risks to public and worker safety and utility operations. The magnitude of this risk was not anticipated back in 2016, when SCE was developing its showing for the 2018 GRC.

D. SCE's RAMP Report Aligns with the S-MAP Settlement Agreement

SCE's RAMP report is consistent with the S-MAP Settlement Agreement (Settlement) that SCE and several other parties submitted to the Commission on May 2, 2018. Table I-I indicates major elements of the Settlement Agreement, along with references to where that element is discussed in SCE's RAMP report. Additionally, Appendix 2 to this chapter provides a more in-depth review of the alignment between SCE's RAMP Report and the Settlement

[16] A.18-09-002.

Agreement. On November 9th, a Proposed Decision was issued adopting the Settlement Agreement.

Table I-I – Alignment of SCE RAMP Report with SMAP Settlement Agreement

Major Elements of the Settlement Agreement	Associated Section of the Settlement Agreement	SCE RAMP Report Sections that Explain SCE's Approach (in addition to Appendix B)
Use of a Multi-Attribute Value Framework (MAVF)	1A	Chapter I, Section I.D.7
Enterprise Risk Register (ERR) as the Starting Point for RAMP Risk Selection	1B, 2A, 2B	Chapter I, Sections I.D.1, I.F.1-5, and I.G
Use of the Bowtie Diagram	3	Chapter 1, Section I.C.1
Mitigations Linked to Drivers and/or Outcomes	3	Chapter III
Measurement of Risk Reduction and Calculation of Risk Spend Efficiency (RSE)	3	Chapter III

E. Corporate Governance of Risk Management

Company senior leadership heavily engages with and manages the enterprise risks at SCE. Enhancements and changes to the risk-informed decision-making framework are regularly communicated to senior leadership, and they actively provide guidance and feedback.

Throughout the year, the Enterprise Risk Management (ERM) group meets with senior leaders to review and discuss enterprise-level risks and mitigation plans. SCE senior leadership plays a critical role in establishing a strong risk assessment culture across the company by actively engaging with enterprise risk management efforts, by encouraging leaders and subject matter experts (SMEs) throughout the Company to participate in the process, and by making this effort one of the company-wide continuous improvement priorities. This support has enabled the ERM group to develop, establish, and implement a more consistent and structured risk-informed decision-making framework.

SCE has a Finance and Risk Management (FRM) Committee, chaired by the SCE Chief Financial Officer (CFO), and consisting of the SCE General Counsel and the Senior Vice President (SVP) of Regulatory Affairs as voting members. The SCE Chief Executive Officer (CEO) and

President are also active participants in FRM Committee meetings; the CEO is required to vote only on matters exceeding certain cost or impact thresholds. The purpose of this committee is to: (1) oversee and approve the allocation of SCE's financial resources, energy procurement activities, and enterprise-wide risk management; and (2) provide a forum and a process to identify, understand, manage and mitigate critical risks related to these areas, in accordance with California Public Utilities Commission (CPUC) directives and company policies.[17]

The leadership team at SCE's parent company, Edison International (EIX), has established a Risk Management Committee (EIX RMC) that oversees SCE's risk management program and enterprise risks. The EIX RMC is chaired by the EIX CFO, and includes as members the EIX CEO, EIX General Counsel, EIX SVP of Strategy and Corporate Development, and the EIX Vice President of Enterprise Risk Management & Insurance and General Auditor ("EIX VP of Risk Management") as a participant. The SCE CEO, CFO, and General Counsel also participate in matters involving SCE risks.

The EIX RMC is responsible for reviewing and understanding critical risks facing SCE. The EIX RMC reviews and approves the annual enterprise risk assessment and mitigation plans. EIX leadership is also responsible for encouraging a corporate-wide culture that makes identifying, managing, mitigating, and reporting risks an integral part of corporate strategy and operations.

Through these various executive committees and forums, oversight of SCE's enterprise risk management program is provided at all levels of the Company. ERM oversight includes:

- EIX and SCE Board of Directors, Board of Directors Audit Committee, and EIX RMC;
- SCE senior management including the SCE CEO, President, CFO, the General Counsel, and FRM Committee;
- EIX VP of Enterprise Risk Management who reports to EIX CFO;
- SCE senior leaders managing OU risks across the Company;
- SCE's Director of Risk Management who reports to the SCE CFO and EIX VP of Risk Management;
- SCE's Principal Manager of ERM who reports to SCE's Director of Risk Management; and
- Risk Advisors and Senior Advisors who report to SCE's Principal Manager of ERM.

[17] The FRM Committee addresses issues related to: capital allocation and investment decisions; annual budgets, operating plans, and long-term financial forecasts; energy procurement; non-energy procurement; executive oversight of compliance issues; executive oversight of business resiliency issues; SCE cybersecurity; and enterprise-level risks and mitigation plans.

Lastly, SCE must be prepared to respond to risk events if they materialize. SCE has developed a strategic approach to minimize the impacts of business disruption by better understanding these threats and fully engaging all areas of the company to develop integrated solutions for responding. These solutions can encompass internal and external stakeholders. For example:

- SCE Incident Management Program – SCE established an incident management structure compliant with guidelines issued by the National Incident Management System (NIMS) and Federal Emergency Management Agency (FEMA) Incident Command System (ICS). The management structure is built around Incident Management Teams (IMTs). An IMT is a group of trained and qualified personnel from different SCE organizational units called upon to lead a response to an emergency or incident.

- Business Impact Analysis – SCE conducts cross-company efforts to determine and prioritize our most mission-critical functions and applications. SCE also maintains business continuity plans and disaster recovery procedures that guide our recovery efforts following any business disruption.

- Emergency Operations Center – SCE has established a dedicated center for detecting, managing, and monitoring emergency events. This includes a situational awareness center to capture weather patterns and analysis, a mobile command center, and a 24x7 Watch Office that monitors our service territory, disseminates important information, and notifies on-call IMTs when needed.

- Coordination with External Stakeholders – SCE performs extensive outreach and coordinated efforts with local, state, and federal agencies, as well as other critical lifeline utilities (gas, water, telecommunications, CalTrans, etc.). This helps ensure we are as prepared as possible for the variety of risk events that could occur in our service territory.

Many of these actions are discussed in more detail in Chapter 12 (Climate Change).

F. Overview of SCE's Risk-Informed Decision-Making Framework Used in RAMP

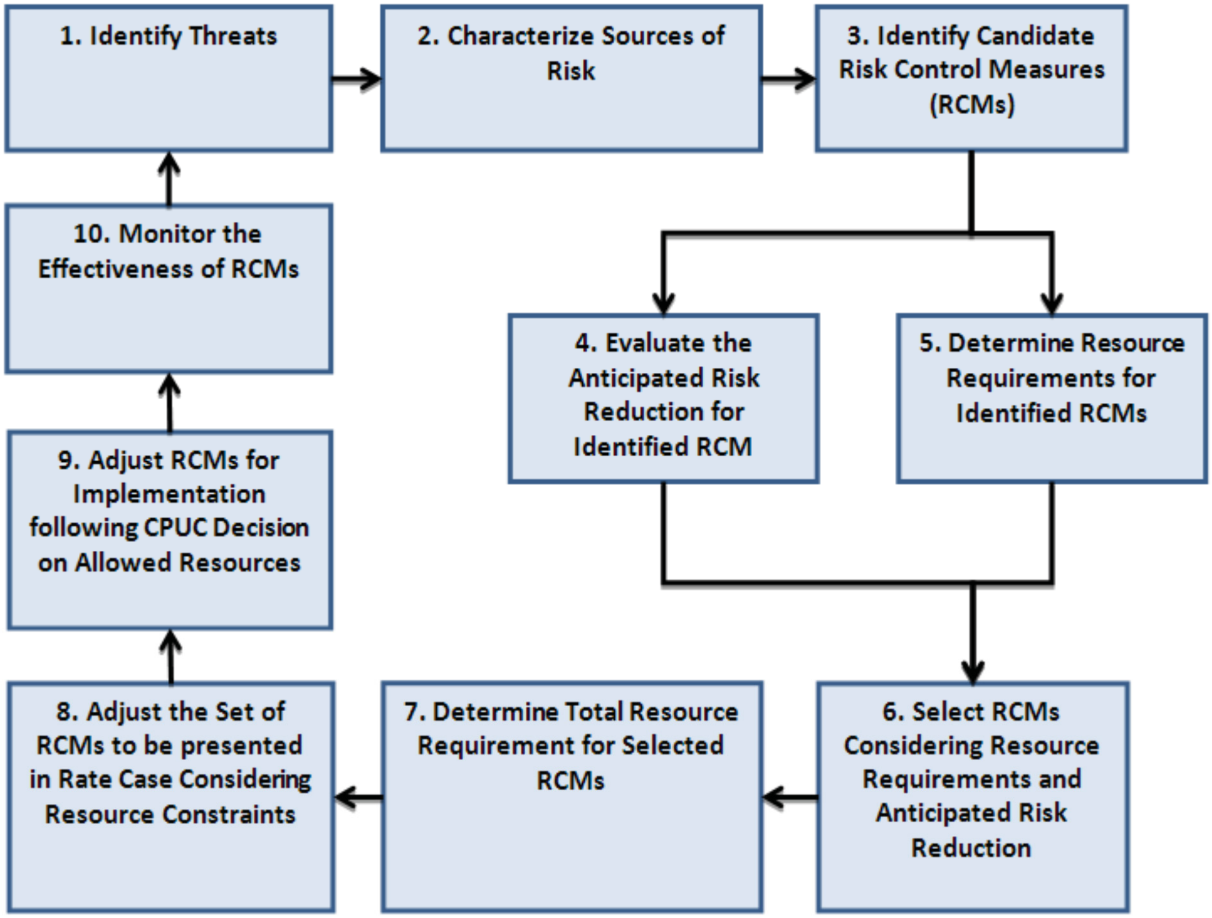
The process of developing this RAMP report has enhanced SCE's risk-informed decision-making framework. This framework enables the company to identify, evaluate, mitigate, and monitor risks and to report on the risks to the company's senior leadership. This framework also lets us explicitly include risk considerations in SCE's decision-making process. Senior leadership employs the framework to review, discuss, prioritize, monitor, and address enterprise risks. This represents an important tool as our senior leaders make decisions to better prioritize and allocate resources to achieve greater risk reductions, where possible.

SCE's risk-informed decision-making framework is built on the foundation we described in SCE's Safety Model Assessment Proceeding (S-MAP) Application.[18] Since filing that Application, SCE has taken measured steps to enhance our internal risk management capabilities. We have benefitted from actively participating in the S-MAP process and collaborating closely with the Commission's Safety Enforcement Division (SED), intervenors, and other California utilities. While this RAMP report represents a prudent step forward in implementing a quantitative risk management framework, we are committed to continuously improving by incorporating best practices and lessons learned, and continuing the collaboration and knowledge-sharing with the Commission and external stakeholders.

The development of SCE's RAMP report followed Cycla's 10-step framework,[19] which is shown in Figure I-2 below. SCE describes our approach to each step in the sections that follow.

[18] A.15-05-002, SCE's Safety Model Assessment Proceeding application, submitted May 2015.
[19] In D.16-08-018, p. 2, this Commission adopted the Cycla Corporation 10-Step Evaluation Method as a common yardstick for evaluating how mature, robust, and thorough utility Risk Assessment and Mitigation Models and risk management frameworks are.

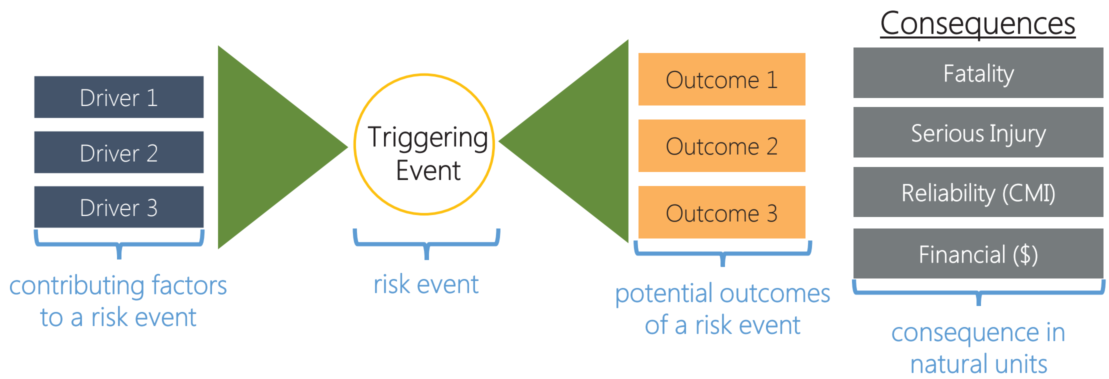
Figure I-2 – Cycla 10-Step Framework



- **Step 1: Identify Threats & Step 2: Characterize Sources of Risk**

SCE begins by developing an understanding of a risk event -- the fundamental elements contributing to the risk event (risk drivers), and the potential negative outcomes and consequences if the risk event is materialized. SCE applied the risk bowtie structure to enable us to consistently and systematically identify threats and characterize sources of risk. The risk bowtie is shown in Figure I-3.

Figure I-3 – SCE Risk Bowtie Structure



- **Step 3: Identify Candidate RCMs (Risk Control Measures)**

SCE has developed a multi-attribute risk scoring (MARS) approach for probabilistically quantifying risk in this RAMP report, based on available data and input from subject matter experts. SCE's MARS approach aligns with Multi-Attribute Value Function (MAVF) principals of the Settlement, and is discussed in more detail in Appendix 2 to this chapter.

For each risk, SCE then assesses existing controls, and identifies potential new mitigation measures that can reduce either the likelihood or the negative consequences of the risk.

- **Step 4: Evaluate the Anticipated Risk Reduction for Identified RCMS**

To estimate the anticipated risk reduction for control and mitigation measures, the effectiveness of each measure on reducing the likelihood and/or consequences of the risk is then estimated. The same MARS calculation is then conducted to estimate the post-mitigated risk score associated with each measure and the resulting risk reduction (benefits).

- **Step 5: Determine Resource Requirements for Identified RCMs**

Besides estimating effectiveness of each mitigation measure, SCE considers multiple factors including timing of deploying the mitigation, resource allocation, technology maturity, alternative mitigations, and other potential considerations[20] to develop a comprehensive and

[20] These requirements and considerations are deliberated in the Proposed and Alternative Plan sections within the individual RAMP risk chapters.

complementary suite of solutions to reduce risks. At this stage, SCE estimates what resources are needed for each mitigation.

- **Step 6: Select RCMs Considering Resource Requirements and Anticipated Risk Reduction & Step 7: Determine Total Resource Requirements for Selected RCMs**

Once we have estimated the cost and risk reduction associated with each mitigation, we then calculate the risk spend efficiency (RSE). This is a measure of risk reduction per dollar spent. It is calculated for each mitigation. RSE helps us estimate the effectiveness of each mitigation, and is also used to compare the effectiveness of different mitigations. RSE is one of the main considerations for selecting and developing a mitigation plan for each risk. We determine the total resource requirements to manage and mitigate a risk by aggregating the resource needs across the various individual mitigation measures contemplated for the mitigation plan. These two steps help us consider all resource requirements to mitigate a risk and to prepare for developing a practical and feasible mitigation plan.

- **Step 8: Adjust the Set of RCMs to be Presented in the GRC Considering Resource Requirements**

For each risk, the mitigation plan is then finalized, taking into account factors such as the feasibility of executing the overall portfolio and applicable resource constraints. The finalized mitigation portfolio for each risk is referred to as the Proposed Plan in this RAMP report. At this time, the RCMs identified in the Proposed Plan represent what we plan to request in the 2021 GRC. As applicable, SCE may further adjust these RCMs in SCE's 2021 GRC, in consideration of broader funding constraints, emergent risks, changes in available technologies, new data or information, or the emergence of alternative methods to mitigate the risk. In addition, for each risk, two alternatives to the Proposed Plan are also presented in each Chapter.

- **Step 9: Adjust RCMs for Implementation following CPUC Decision on Allowed Resources & Step 10: Monitor the Effectiveness of RCMs**

This RAMP report follows the first eight steps of the Cycla 10-step framework. The final two steps: Step 9 (adjust RCMs for implementation following CPUC decision on allowed resources), and Step 10 (monitor the effectiveness of RCMs), are not directly applicable to this RAMP report. However, for context, SCE plans to complete Step 9 following a decision on our

2018 GRC. Consistent with D.14-12-025, SCE plans to subsequently address Step 10, which may involve the completion of the Risk Mitigation Accountability Report.

G. RAMP Top Safety Risks & Process to Identify Them

SCE went through a rigorous process to identify the top safety risks that merited inclusion in RAMP. Each of these top safety risks is summarized in Figure I-4 below, and examined in detail in the individual chapters of this report.

Figure I-4 – SCE RAMP Risks

The foundational component of this RAMP report is determining the top safety risks. SCE made significant efforts to help ensure we captured the right risks. We did this through the four general steps shown in Figure I-5:

Figure I-5 – General Process to Identify RAMP Risks

"Top Down" review of Enterprise-Level Risks → "Bottoms-Up" review of SCE Enterprise Risk Register → Consolidation & Aggregation → Senior Leadership Review Sessions

1. Top-down review of enterprise-level risk report

Every year, SCE identifies and evaluates the key enterprise risks facing the company. This effort is informed by a review of industry trends and research, internal risk analyses on major initiatives and key business functions, public policy efforts, and regulatory proceedings (including, most prominently, Commission proceedings). This effort also reflects feedback obtained through company-wide surveys and direct discussions with SCE leadership. Qualitative adjustment may be applied based on calibration discussions among cross-functional risk managers and among SCE officers. The list of key enterprise risks is reviewed and refreshed regularly, and changes when a new risk is identified and added, or retired and subtracted.

SCE regularly benchmarks and monitors what other utilities and Fortune 500 companies are classifying as their top risks. We also participate in various ERM forums and roundtables, including Edison Electric Institute (EEI), Deloitte, Gartner/Corporate Executive Board (CEB) Risk Management Leadership Council, and Risk Management Society (RIMS).

SCE evaluated this "top-down" enterprise risk refresh effort from 2017 with an eye towards safety-related risks identified in the report. SCE captured these safety-related risks to compare against the safety risks identified in our Enterprise Risk Register.

2. Bottoms-up review of SCE Enterprise Risk Register

SCE maintains an enterprise risk register that captures and assesses key risks from across the enterprise. The risk register has been populated over the past several years and lists our principal safety and reliability risks. It is intended to be a living document, and we update and modify it as necessary over time. To identify potential new and emerging enterprise risks and to validate existing risks, we engage in Company-wide online surveys directed to a large number of directors, managers, and subject matter experts, along with targeted interviews with specific and relevant risk managers. The interviews are typically followed by cross-functional group workshops and brainstorming sessions to further assess and validate the risk selection and nature of those risks.

To identify RAMP risks, SCE reviewed the risk register and identified risks with a potential major safety consequence (potential for serious injuries or higher) to consider in RAMP.[21]

3. Consolidation and aggregation

SCE evaluated the safety risks resulting from these top-down and bottoms-up analyses. This exercise involved consolidating duplicate risks and aggregating similar risks together. By using a common framework and terminology, we created a structured and uniform set of risks.[22] SCE applied the risk bowtie structure to enable this. The risk bowtie, as show in Figure I-3 above, is a way to systematically and consistently evaluate the drivers, outcomes, and consequences of a risk event.

In addition, SCE evaluated the relative order of impacts from each risk event. SCE considered whether a risk event would result in first-order direct safety impacts, or if it might result in second-order indirect safety impacts. As discussed further in Section I below, SCE is only measuring the first-order direct safety impacts resulting from a risk event. As such, SCE removed those risks that primarily focused on second-order, indirect safety impacts.

4. Review and refine with senior leadership

On several occasions, SCE discussed the potential RAMP risks with the leadership team to refine this consolidated set of safety risks. Further refinements were made based on these discussions. Sometimes, the scope of proposed risks were increased; other times the scope was reduced. For example, SCE was initially proposing to focus solely on building safety from the lens of seismic event risks. However, we expanded the scope to explore electrical hazards, building fires, and environmental events that could have potential safety impacts to workers in buildings. In other cases, we consolidated risks even further together. For example, SCE originally had a standalone Insider Threat risk. After much discussion, we determined that insider threat activities would be better served as drivers to the Cyberattack and Physical Security risk chapters.

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[21] Please refer to WP Ch. 1, pp. 1.2 – 1.4 *(Risk Register to RAMP Risk Mapping)*.

[22] For example, a key safety risk for SCE is human contact with energized conductor. This contact may occur for a variety of reasons, including but not limited to equipment failure, accidental contact, etc. In the process of structuring the RAMP risks, SCE addresses the contact with energized conductor in two chapters, according to the drivers of the contact: Chapter 7 (Employee, Contractor & Public Safety) evaluates human contact with energized conductor caused by an act an SCE worker performs. Conversely, Chapter 5 (Contact with Energized Equipment) evaluates contact with energized conductor caused by failure of overhead assets (e.g., wire down event), or failure of a third party to recognize his/her proximity to energized conductor (e.g., private party tree trimmers).

5. Discussion with external stakeholders

As mentioned in the Executive Summary above, on several occasions SCE met with external stakeholders to review and solicit feedback on the risks we proposed to include in RAMP, and to outline the analysis we were undertaking. SCE appreciates the collaborative feedback we received, and looks forward to further conversations as we move through the RAMP OII process.

6. Risks that were strongly considered for inclusion in RAMP

This process yielded nine risks, and in this RAMP report we have performed detailed probabilistic analyses regarding each risk. Through this process, some safety-related risks were omitted for various reasons. For context, some of these included:

Table I-II – Risks Not Included in RAMP

Risk	Description	Rational for Exclusion
Electrical System Failures - System-Wide Blackout	System-wide blackout caused by equipment, asset, or system failure.	Safety impacts would be secondary and indirect, which SCE is not capturing in this RAMP report (see Section I (Key Parameters and Assumptions Underlying SCE's RAMP Report) for further detail).
Vehicle/Aircraft Failure	Safety consequences caused by the actual failure of a vehicle, bucket truck, crane, helicopter, etc., and not human error.	Incidents due to asset failure (e.g., the vehicle has a problem, not the human operator) are very rare. For vehicles, fewer than 5% of incidents with OSHA-recordable injuries were potentially due to vehicle failure. For helicopters, based on FAA historical accident data and the current extent of SCE helicopter operations, the likelihood of potential safety incidents is low.
Customer Service System Outage	Failure or prolonged outage of SCE's customer service IT systems that manage our website, customer data warehouses, and electronic communications with our customers, leading to delays in handling power outage reporting or other public safety requests from our customers.	SCE found that most of the safety risks associated with this event were secondary and indirect.

H. Appendices: Qualitative Assessment of Other Safety Risks

While developing this RAMP report, SCE received valuable feedback from several external parties recommending that we address certain risks in the RAMP report that are not covered in the nine risk chapters. Accordingly, SCE includes two Appendix chapters that address the following risks using qualitative risk analysis, and one additional appendix that provides greater context concerning our seismic program.

- Nuclear Decommissioning (Appendix A): SCE addresses the safety risks associated with SCE's San Onofre Nuclear Generating Station (SONGS) during the process of decommissioning the facility. SCE mitigates these safety risks by carefully adhering to Nuclear Regulatory Commission (NRC) radiological safety regulations, as well as other requirements from Federal and State regulatory bodies.
- Transmission & Substation Asset Safety (Appendix B): In this appendix chapter, SCE qualitatively assesses direct safety risks associated with the transmission and substation systems.
- Seismic Events (Appendix C): As seismic events are incorporated into SCE RAMP risk chapters as a risk driver, SCE uses Appendix C to provide greater context to our overall Seismic program.[23]

I. Key Parameters and Assumptions Underlying SCE's RAMP Report

Consistent with Commission direction, SCE intends that the data, assumptions, and methods used to develop this RAMP report be transparent and understandable to the Commission and interested Parties. Throughout this report and associated workpapers, SCE documents the data and rationale used to evaluate the risk and risk mitigation activities for our top safety risks. We believe that this report will provide all parties, including Commission Staff, with the opportunity to understand the analysis, data and assumptions underlying our submission.

Because this is the first time SCE has developed a RAMP report, SCE had to consider and establish an approach for myriad issues that affect the evaluation of RAMP risks and mitigations. This section provides context into several of these issues, and explains how SCE approached them.

[23] Seismic events are included as a driver to the Hydro Asset Safety and Building Safety risks. A summary of SCE's seismic mitigation program is discussed in Appendix C (Seismic Events) of this RAMP report.

1. Risk Impacts Measured in RAMP

In this RAMP report, SCE only evaluates the immediate impacts of a risk event. That is, when a risk outcome occurs, SCE measures only the direct impacts of that outcome, and not those of subsequent outcomes which may ultimately result.

For example, consider the risk event of an underground equipment failure, which causes the power outage of traffic lights at a traffic intersection. SCE will measure, among other consequences, the resulting reliability impacts from that outage. In this RAMP report, SCE does not, however, evaluate the potential impacts from car accidents that occur because the traffic lights are out. While this secondary impact is certainly possible and SCE is of course concerned about it, we find it difficult to quantitatively forecast with any reasonable degree of confidence the number and severity of traffic accidents that would result from such a power outage. As a result, we evaluate only the immediate and direct impacts of the risk event (e.g., underground equipment failure) in this RAMP report.

The result of only evaluating first-order impacts is that the risk analyses found in this report likely underestimate the magnitude and extent of each risk. SCE may consider alternative means to address this in future RAMP reporting.

2. RAMP Time Period

SCE has evaluated risk, risk reduction, and RSE over the 2018-2023 period. SCE used 2018 as the first year to model risk, as this allows our risk baseline[24] to be firmly rooted in what we have experienced through 2017. This is similar to the "base year" concept in a GRC. SCE evaluates risk through 2023 as that corresponds to the final test year of our 2021 GRC.

SCE recognizes that only evaluating risk reduction and RSE over the 2018-2023 period can be problematic for mitigations with benefits and costs extending beyond 2023. This is especially the case for long-lived assets that are installed during the RAMP period, and then continue to operate and provide benefits for many years thereafter. There can be dissonance in RSE comparisons between this type of mitigation, and for example, an O&M expense-driven mitigation that has short-lived benefits. In these cases, the long-lived mitigation will have an RSE that is understated compared to the short-lived mitigation.

[24] For purposes of this RAMP report, the baseline risk level represents the estimated risk at the end of 2017.

To help us understand the implications of this, and to help build capabilities to capture and model long-term benefits and costs beyond the RAMP period, SCE has piloted an approach to capture the risk reduction benefits beyond 2023. Please refer to the Appendix of Chapter 8 (Hydro Asset Safety), which performs such an evaluation on the Hydro Asset Safety chapter. In addition, SCE performed a similar analysis on the Wildfire Covered Conductor Program, which can be seen in the Appendix to Chapter 10 (Wildfire). SCE plans to continue to evaluate how best to incorporate the full benefits and costs of risk mitigation activities, and we look forward to working with the Commission and interested parties to develop this capability.

3. Treatment of risk mitigation activities that appear in multiple risk chapters

In a few cases within this RAMP report, a control or mitigation may address multiple risks. Where this occurs, SCE either (1) models the benefit of the mitigation to the specific risk bowtie evaluated in the chapter, while incorporating the full cost of the mitigation, or (2) models the mitigation within the chapter of primary benefit, and qualitatively discusses how the mitigation affects the risk in the chapter receiving the indirect benefit. In cases of the former, SCE does not attempt to split or apportion the costs of that mitigation to each risk. Instead, the full costs of the mitigation are included in each chapter where a mitigation is modeled. However, within each chapter, *the risk reduction benefits* of that mitigation are quantified *only* with respect to its impact on that chapter's risk bowtie. In effect, this may underestimate the RSE of the mitigation as a whole. We are showing the full costs in each chapter, but not necessarily the full risk reduction benefits.

The controls and mitigations that are modeled in multiple chapters are identified in Table I-III. There are also several other controls and mitigations shared between the Wildfire and Climate Change chapters; these are discussed further in those respective chapters.

Table I-III – Controls & Mitigations in Multiple Chapters

Control/Mitigation	Contact with Energized Conductor	Wildfire	Climate Change
Overhead Conductor Program	X	X	
Covered Conductor	X	X	
Situational Awareness Tools		X	X

While costs may appear in multiple RAMP chapters, SCE will address any such duplication when developing our 2021 GRC request.

4. Financial Information Presented in RAMP

a. Cost Estimates

SCE has developed preliminary cost estimates for the 2018-2023 RAMP period for each control and mitigation activity. The costs are not jurisdictionalized. They represent total company unadjusted expenditures regardless of regulatory cost recovery mechanism. SCE presents these costs, both O&M and capital, in nominal dollars. For controls and mitigations funded through capital expenditures, SCE does not include capital-related expense, which typically amounts to less than 2-3% of the capital spend. As this exclusion does not materially change the risk analysis, SCE will address capital-related expense in the 2021 GRC.

It is important to note that these costs are estimates at a point in time. Using reasonable efforts, SCE has developed our estimated forecast costs for each control and mitigation in this report, based on the information available when we prepared this RAMP report. We expect our 2021 GRC will further refine the cost estimates shown here.

b. Recorded Costs

Within each chapter, SCE includes the 2017 recorded costs for each compliance and control activity. These costs represent total company, unadjusted costs in nominal dollars, including balancing/memorandum accounts. SCE has provided a workpaper that details the recorded and forecast costs for each compliance, control, and proposed mitigation activity modeled in our RAMP report from 2013 – 2023.[25]

5. Use of Subject Matter Expertise (SME) in RAMP

Wherever possible and practicable, SCE has used data pertaining to our own system to support our risk analyses. Where this is not available, we look to other utilities in California, or other utilities around the country, for data and information comparable to our operating environment and size. When such data does not exist, we rely on the judgment of subject matter experts (SMEs) to develop assumptions for risk models.[26] Where this occurs, SCE has endeavored to explain the assumptions and processes used to develop such judgment in the chapter or associated workpapers.

[25] Please refer to WP Ch. 1, p. 1.1 *(2013 – 2023 Recorded and Forecast Costs for Controls & Mitigations)*.
[26] These categories of information are not mutually exclusive. For example, the availability and use of SCE-specific data does not cancel out exercising appropriate judgment.

J. Global Challenges and Lessons Learned in Development of RAMP Report

This section identifies general challenges we have faced and overall lessons learned that we have obtained through developing our first RAMP report. In addition, each chapter identifies lessons learned that are specific to that chapter.

1. RAMP Time Period

In some cases, the RAMP time period of 2018-2023 does not fully capture the duration of expected costs and benefits. For example, conductor upgrades have a useful life measured in decades. On the cost side, mitigations installed during the RAMP period can require ongoing maintenance costs that extend beyond 2023.

The most common issue resulting from limiting the analysis time period to 2018-2013 was a failure to fully capture the longer-term risk-reduction benefits of a long-lived Control or Mitigation. This leads to an understatement of the RSE.

This analytical limitation is most visible in the chapters addressing Wildfire, Contact with Energized Equipment, Underground Equipment Failure, and Hydro Asset Safety. SCE believes that the mitigations in these chapters, particularly the longer-lived infrastructure programs, would have a materially higher RSE if the long-term benefits were captured.

RSE is not the only factor SCE considered in selecting proposed mitigation portfolios, and the duration of particular Controls and Mitigations is considered qualitatively. However, addressing long-term benefits will be a goal for future RAMP filings.

As previously discussed, SCE used the Hydro Asset Safety risk to pilot a methodology to capture the complete time horizon of both costs and benefits. This is shown in Appendix 1 to the Hydro Asset Safety chapter. SCE calculated a complete lifetime of both costs and benefits, accounted for factors such as degradation of mitigation effectiveness over time, and then discounted the costs and benefits to a present value. SCE performed this analysis with several discount rates to illustrate the impact under different scenarios. In addition, SCE performed a similar analysis on the Wildfire Covered Conductor Program, which can be seen in the Appendix to Chapter 10 – Wildfire.

SCE found that a long-term analysis did materially change the RSEs in that chapter, and that using different discount rates can change the results of the present value analysis, depending on how long the mitigation is used.

2. Primary and Secondary Impacts

In this RAMP report, SCE measured risk outcomes at the level of immediate (i.e., primary) impacts across specific consequences (serious injuries, fatalities, financial, and reliability). SCE did not measure secondary impacts (for example, the hypothetical car accident that occurs because a traffic light is out due to underground equipment failure).

At this time, attempting to measure secondary impacts in this RAMP report would be challenging and highly unlikely to achieve an acceptable degree of certainty. SCE concluded this after extensive internal discussions confirmed that secondary impacts cannot be identified, defined, or measured with the level of certainty and credibility necessary to inform the immediate RAMP risk analysis calculations.

For example, using the hypothetical scenario above of a traffic light that has lost power, one would need to speculate on questions such as the time of day, how many cars pass through the intersection, the occupancy of each car, whether an accident occurs, whether the accident results in serious injuries or fatalities, how many accidents occur before power to the traffic light is restored, whether law enforcement had been on hand to direct traffic after the light was reported out, etc. As this limited example illustrates, attempting to define and measure even a modest slice of the potential secondary impacts of a risk event is fundamentally speculative and uncertain.

SCE discussed these challenges extensively during development of its RAMP filing, and SCE appreciates that the "solution" to this difficulty—only measuring primary impacts relative to the outcomes defined in the bowtie statement—presents a view of the risk that does not cover the full range of potential impacts. SCE notes that both risk outcomes and mitigation effectiveness measurements ignore secondary impacts; in other words, just as SCE is not including secondary impacts in measuring the size of risk outcomes, SCE is not including secondary impacts in measuring the risk reduction potential of mitigations. SCE will continue to evaluate secondary risks for potential inclusion in future risk analyses.

3. Mitigations in Multiple Chapters

As discussed in Section I.3, SCE identified mitigation measures that provide benefits across multiple risks. SCE took the approach of calculating RSE values independently. As a hypothetical example, assume that a mitigation costs $100 and provides 20 MARS points of risk reduction in Chapter A, and 30 MARS points of risk reduction in Chapter B. The RSE for that mitigation would be calculated as follows for each chapter:

- In Chapter A, the RSE is 20 / $100 = 0.2
- In Chapter B, the RSE is 30 / $100 = 0.3

This approach potentially understates the risk reduction by not showing its combined impact across both risks. The alternative would be to sum the total risk reduction. In the hypothetical example above, the RSE would be calculated as follows:

- (20 + 30) / $100 = 0.5

SCE determined that, although it might understate some RSE values, accepting this limitation for our initial RAMP report was appropriate until further exploration (e.g. through the S-MAP process, etc.) could inform a more comprehensive approach.

4. The Bowtie Framework

Although SCE's utilization of the bowtie framework for risk analysis predates this RAMP report, the RAMP report provided further opportunity to apply the bowtie approach across numerous business areas. This helped us develop a deeper understanding of the strengths and weaknesses of the approach.

The bowtie provides a simple and effective means to translate high-level conceptions of risk (e.g. "wire-down" or "worker injury" or "building fire") into a more structured understanding that articulates the difference between risk drivers, risk events, and risk outcomes. The bowtie's ability to define and disaggregate the components of a risk can be especially helpful when working with subject matter leads who may be experts in their particular line of business, but are less fluent in the discipline of risk definition and analysis. Furthermore, the bowtie serves as an effective risk organizing principle regardless of whether the ensuing analysis is quantitative or qualitative.

The bowtie is most effective when applied to risks where the outcomes are largely indifferent to the drivers. For example, if an energized wire is on the ground, the safety risk and the potential range of outcomes have little to do with why the wire is down in the first place (the driver). True to the bowtie's design, the potential outcomes are independent of the potential drivers.

This feature of the bowtie—its design feature that maintains independence between drivers and outcomes—was a challenge for risks that are more extensive in scope or include a complex network of drivers and outcomes.

For example, the risks in the Building Safety chapter are highly diverse, from earthquakes to weather conditions to fires. The drivers and outcomes for these risks are tightly linked; an electrical failure will not lead to the outcome of building shaking, but such building shaking would occur from a seismic event. In these cases, additional analysis can be required to help ensure the bowtie adequately captures driver and outcome data. Furthermore, applying the bowtie to a diverse or complex risk usually requires broadening the risk event in the center of the bowtie to a point where it can be overly generalized.

SCE highlights these aspects of the bowtie framework to explain the bowtie strengths and weaknesses in the context of both RAMP and utility safety risk management more broadly. Despite the limitations mentioned above, SCE sees the bowtie as an appropriate approach to proceed with for the foreseeable future, unless or until a more fitting alternative is identified.

5. MARS/MAVF Framework

As described previously, SCE used the MARS framework to implement the concept of a Multi-Attribute Value Function (MAVF), which allows risks to be understood in terms of both natural units and a generic, unit-less risk score. MARS scoring can provide a mechanism for enabling apples-to-apples comparisons across dissimilar risks and mitigations, as long as the underlying risk inputs are consistent.

However, the same MARS feature that allows for cross-risk comparisons—the conversion of natural units into unit-less risk points—results in a metric that offers no intuitive sense of value by itself. Unlike natural units, which can be understood intuitively on both a standalone basis and relative to other company goals or projects unrelated to RAMP, an individual MARS result can only be compared to other MARS results that were derived using an identical framework.

Finally, as with many risk scoring systems, the MARS/MAVF framework relies on key underlying assumptions such as the ranges and weights of attributes; any internal or external party that disagrees with those assumptions might struggle to find value in the resulting MARS values.

Despite these limitations, a MARS/MAVF framework provides an essential complement to measuring risk from the perspective of natural units. As noted above, absent converting risk measured in natural units into MARS points, it would not be possible to compare risk outcomes on a comparable basis.

This RAMP report provided SCE with an opportunity to educate organizational units within the Company on the MARS/MAVF concepts. SCE plans to continue these efforts as these types of risk scoring processes are further integrated into internal decision processes and risk management activities. SCE also attempted to make the MARS score more intuitive by setting a maximum combined score of 100 (meaning a risk that has the highest impact in all dimensions would have a total MARS score of 100). This provides an intuitive reference point for the relative value of a MARS score for an individual risk.

6. Data and Risk Quantification

RAMP's focus on quantification lends itself to risks that can be narrowly defined and readily measured. Risks that are larger in scope or complexity, that are challenging to limit to discrete risk events, or that are difficult to quantify can be a challenging fit with the RAMP analysis framework. Hence, SCE presents the findings and analysis in this RAMP report as a basis to help *inform* risk-related decision making, but not as a sole or controlling basis for such decision making.

Similar to challenges faced by other utilities, quantification can be challenging where the RAMP approach required data that SCE had not previously tracked. In the individual risk chapters, SCE has noted areas in which improved data availability or tracking should enhance the quantitative analysis.

Quantification was also challenging in areas that lacked a historical precedent of risk events, regardless of whether SCE was tracking data in that area. For example, SCE has never experienced a hydro dam failure, and thus has no historical body of failure events that can inform a forward-looking forecast. SCE attempted to find industry or external data in such cases, but those sources may not provide the same level of accuracy or relevance as a forecast based on historical data directly from the risk population in question. Furthermore, in areas in which data is sensitive or classified (e.g. cybersecurity or safety risks in litigation), complete industry data may not be available.

SCE plans to address the above challenges with several approaches:

- New or improved data collection in areas where the data exists, but had not been tracked in a way that was conducive to RAMP analysis needs. Details of these efforts and plans are provided in the concluding section of each risk chapter.
- With the knowledge and experience gained from its initial RAMP filing, SCE will be more able in future RAMP filings to spot areas where SCE-specific data is not available, and to devote more time upfront to identify external data

sources and develop the necessary assumptions and analytical approaches to adapt external data to the particular risk in question.

- With regard to cases in which data is available but a poor fit, or cases in which risk drivers or outcomes are challenging to model, SCE notes that the RAMP process led to significant advancements in SCE's internal capabilities to perform advanced risk modeling and analysis. SCE's abilities in these areas are significantly stronger as a result of developing the RAMP filing, and SCE expects this gain to yield benefits in the next RAMP filing when it comes to quantifying and modeling complex risks.

K. Availability of Risk Model Data and Results

SCE will furnish the risk models and data files used to perform the risk analysis in this RAMP report upon request. The size of these files and the volume of data within them make it prohibitive to send via email and without proper context. To request the risk models, please send an email to Case.Admin@sce.com and reference the 2018 RAMP report in the transmittal.

Due to the amount of data produced in each model, SCE has developed a more intuitive reporting interface for stakeholders to view and evaluate the inputs and outputs of the risk models. This was developed through Microsoft's PowerBI tool. This is available to anyone with an internet connection; no software installation is needed. Data from the charts and tables in this tool can be downloaded directly to your computer for further analysis. We encourage stakeholders to use this tool to help understand the quantitative aspects of this RAMP report.

For directions on how to obtain access to this resource, and for a tutorial on how to navigate the tool once you have access, please see the associated workpapers.[27,28] Additional detail on this tool and its contents can be found in Chapter II – Risk Model Overview.

[27] Please refer to WP Ch. 1, pp. 1.5 – 1.8 *(RAMP Power BI Access Form & Sign-up Instructions)*.

[28] Please refer to WP Ch. 1, pp. 1.9 – 1.40 *(RAMP Power BI User Guide)*.

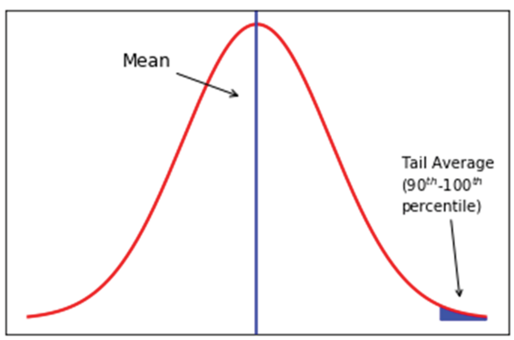
II. Appendix 1: RAMP Summary Results

A. Mean vs. Tail-Average Results

Throughout this RAMP report, SCE provides results within each chapter in terms of "mean" and "tail-average." It is important to understand the difference in these two results. SCE's probabilistic risk model simulates 10,000 scenarios based on the data inputs and parameters of bowtie elements, including drivers, triggering events, outcomes, consequences, etc. Figure II-1 illustrates this difference in these results.

- The mean is the average of all 10,000 simulation results.
- The tail-average is the average of the worst 10% of all 10,000 simulation results.

Figure II-1 – Distribution of Modeling Results



For some RAMP risks, it may be more productive to evaluate results on a mean basis; for others, tail-average would be more relevant. For example, the Hydro Asset Safety chapter considers the consequences resulting from the failure of a dam. A dam failure has not, and is not expected to, happen regularly. In fact, such a dam failure has an incredibly low likelihood of occurring, but when it does occur, the consequences can be catastrophic and widespread. Such an extreme risk may be more appropriate to evaluate on a tail-average basis.

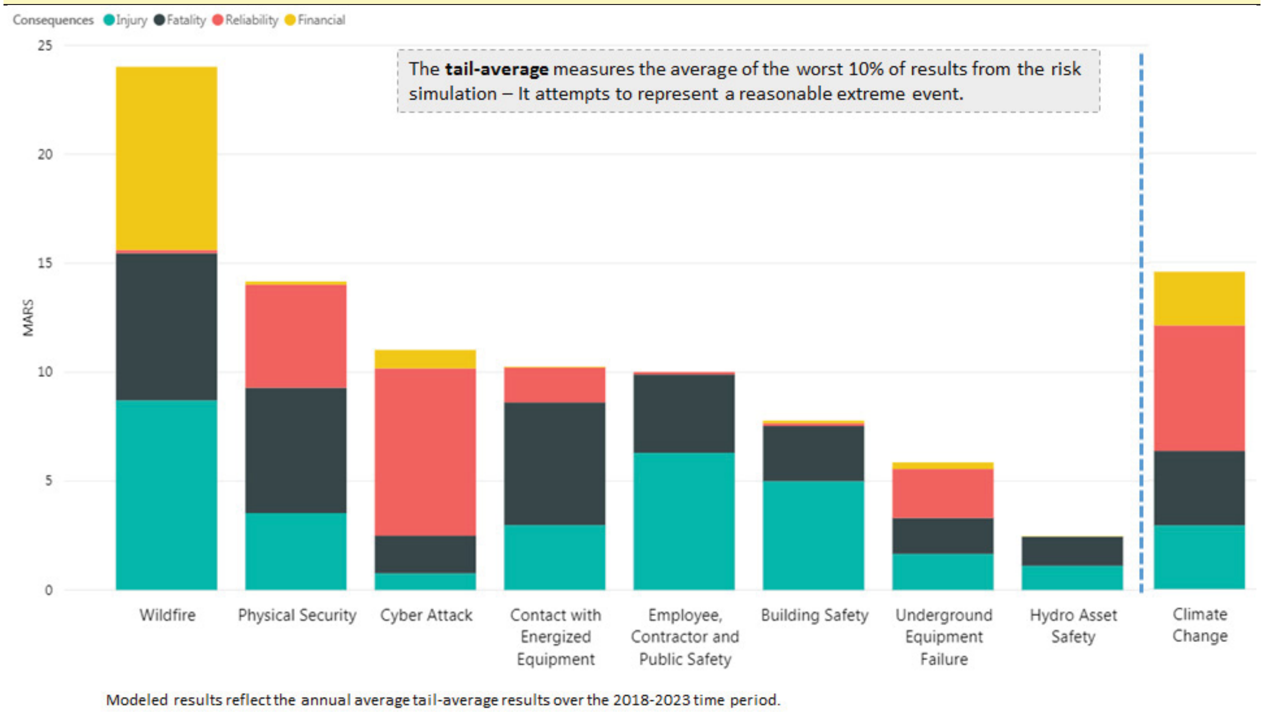
Conversely, the Employee, Contractor, and Public Safety chapter considers consequences resulting from acts performed by workers that lead to injuries. Unfortunately, this happens on a more frequent basis – there are a number of safety incidents ranging from ergonomic issues, to injuries requiring first aid, to serious injuries requiring hospitalization that occur each year. When these incidents happen, the impacts are typically isolated to the person performing the act. Considering these incidents occur with greater frequency and have localized impacts, it may be more appropriate to evaluate on a mean basis.

Because both the mean and tail-average results can provide valuable insights into the nature of each risk, SCE has included both results throughout this RAMP report.

B. Summary Baseline Results

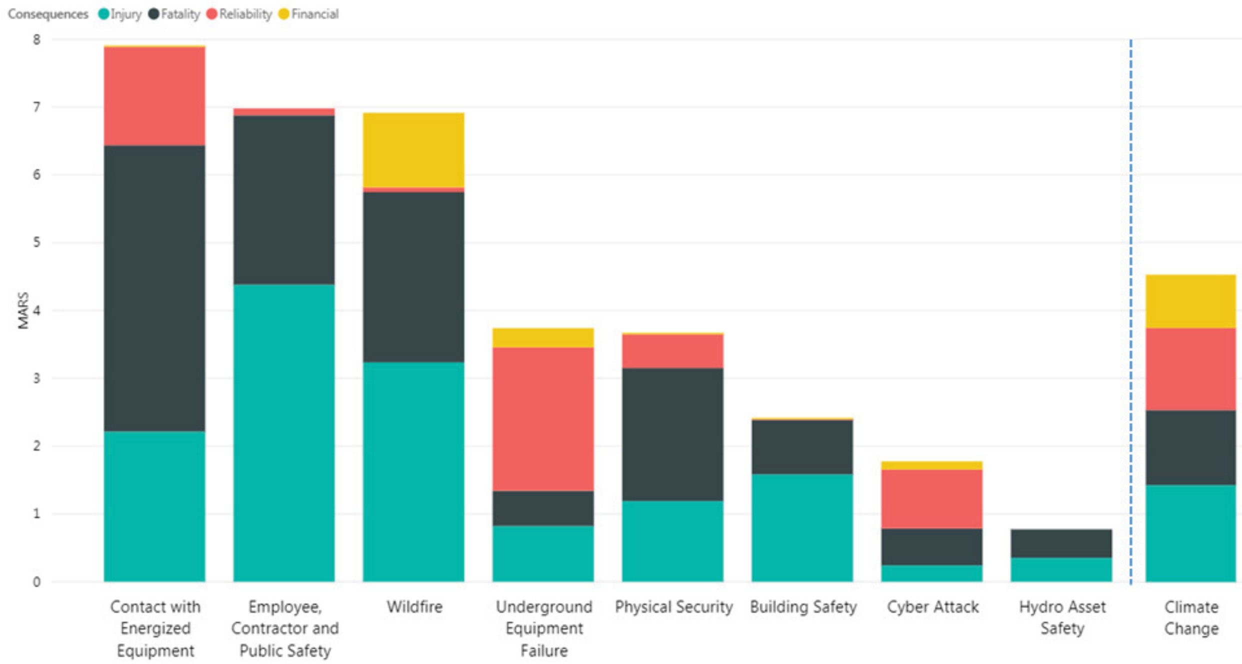
Figure II-2 and Figure II-3 show the baseline scores for the nine risks modeled in RAMP, on a tail-average and mean basis. These baselines reflect an average of the modeled results over the 2018 – 2023 period.[29]

Figure II-2 – Baseline Risk Scores (Tail-Average - MARS)



[29] Climate Change is shown off to the side for two reasons: (1) As is discussed in Chapter 12 – Climate Change, the risks associated with climate change are impactful to varying degrees over the near-, medium-, and long-term time horizons. This RAMP analysis reflects impacts over the 2018-2023 RAMP period. We were not able to capture the gradual and long-term impacts, such as drought, snowpack, sea-level rise, etc. over the near-term using the RAMP model. (2) In the RAMP analysis, SCE modeled the near-term extreme (99th percentile) climate change risks (extreme rain, heat, and wildfire). This means that the climate change results shown are much further on the distribution of outcomes than the tail-average results shown for the other eight risks. As such, the comparison is not entirely like-for-like.

Figure II-3 – Baseline Risk Scores (Mean – MARS)



Modeled results reflect the annual average mean results over the 2018-2023 time period.

III. Appendix 2: RAMP Report Aligns with the S-MAP Settlement Agreement

As described below, SCE's RAMP report is consistent with the S-MAP Settlement Agreement (Settlement) that SCE and several other parties submitted to the CPUC on May 2, 2018, and to which the Commission has issued a Proposed Decision adopting.

A. Use of a Multi-Attribute Value Framework (MAVF)

For this RAMP report, SCE developed a MAVF approach, referred to as MARS, consistent with principals that S-MAP settling parties agreed on. This approach: (1) measures potential risk consequences in terms of natural units; and (2) converts natural units into a standardized unit-less risk score that can be compared across risks.

Consistent with the S-MAP Settlement, SCE is evaluating the risk impacts associated with the following consequences: Safety (measured separately through Serious Injuries[30] and Fatalities), Reliability (measured in customer minutes of interruption (CMI)),[31] and Financial (measured in dollars).

And in accordance with the process outlined in the S-MAP Settlement, SCE's RAMP report utilizes:

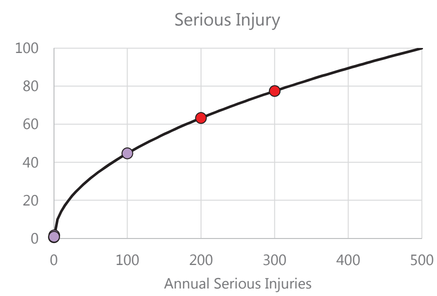
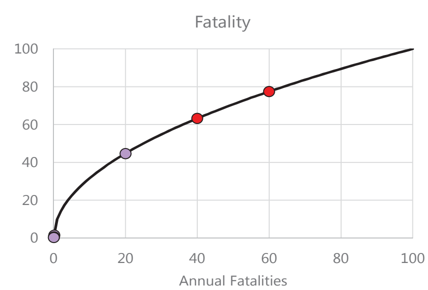
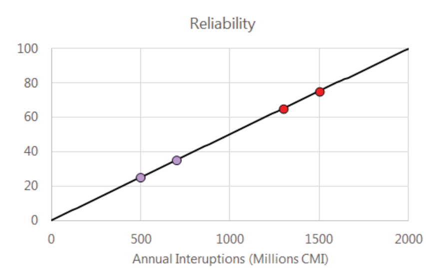
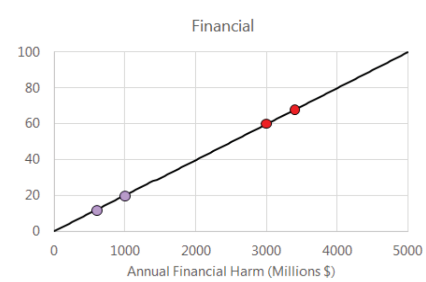
- Attributes to define potential types of consequences (e.g., reliability) and natural units to measure the consequence (e.g., customer minutes of interruption).
- An upper and lower bound to define a range for each attribute (e.g., $0 to $5B for a financial attribute).
- A scaling function that translates each range of natural units into a 1-100 score of generic unit-less risk score.
- Weights that indicate the relative value of attributes.
- Multi-attribute risk scoring (MARS), which is the weighted average sum of the unit-less risk scores across all the applicable attributes for each risk. Under SCE's method, each risk can have a maximum MARS score of 100.

Figure III-1 summarizes the MARS attributes that SCE uses in this RAMP report.

[30] For purposes of this RAMP report, SCE is generally defining serious injuries using the EEI Serious Injury definition. Please refer to WP Ch. 1, pp. 1.41 – 1.46 *(EEI Serious Injury Definition)*.

[31] Customer Minutes of Interruption can be applied to SCE's customer base to derive another common reliability metric, SAIDI (System Average Interruption Duration Index).

Figure III-1 – Summary of SCE MARS Placeholder Values

Consequence *(Natural Unit)*	**Range**	**Scaling Function**	**Weight**
Serious Injury *(# of Serious Injuries)*	0 – 500	Square Root 	25%
Fatality *(# of Fatalities)*	0 – 100	Square Root 	25%
Reliability *(Customer Minutes of Interruption – CMI)*	0 – 2 Billion CMI	Linear 	25%
Financial *USD ($)*	0 – $5 Billion	Linear 	25%

1. Selection of Ranges

Ranges accommodate the worst reasonably possible consequence for each risk over the course of the year. To estimate ranges for each consequence, SCE considered past events that SCE or other utilities experienced (e.g., financial consequences that California utilities and their customers experienced as a result of the year 2000 energy crisis) or potential scenarios in the future (e.g., an eight-hour outage across the entire SCE service territory)

2. Selection of Scaling Functions

The scaling function aligns each consequence's natural unit range to a generic, unit-less range from 0 – 100. This allows for translation to a common metric for comparison.

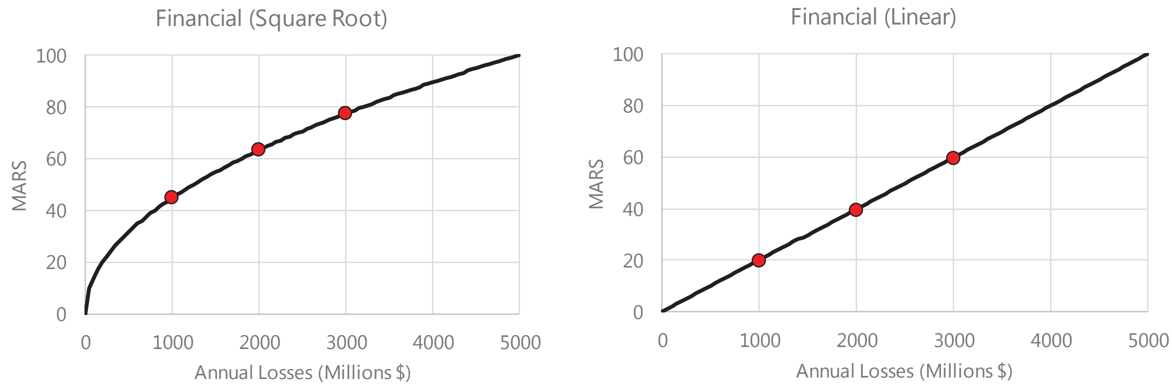
Table IV – Scaling Function Rationale

Consequence	Scaling Curve	Description / Rationale for Use
Serious Injury	Square Root	This curve exhibits a steep slope on the lower end of the scale, reflecting the gravity for safety consequences. It amplifies the impact of safety versus the consequences which have a linear curve. This reflects SCE's intolerance for safety-related consequences.
Fatality		
Reliability	Linear	Maintains simplicity of measurement in converting to MARS. It does not presume a level of customer tolerance to short- or long-duration outages.
Financial	Linear	Maintains simplicity of measurement in absence of data showing relative level of aversion to impacts at the lower and upper bounds of range.

Figure III-2 provides an illustrative comparison of the differences in MARS score for a financial consequence when using the square root scaling function versus the linear scaling function. The square root function has a steeper curve and results in a higher MARS score versus a linear scaling curve given the same natural units,[32] further amplifying the impact of safety consequences to the overall aggregate MARS for each risk. This variance is most pronounced on the left-hand side of the curve, when the number of natural units are less.

[32] This is true except for the first and last value (0 and maximum value of the natural unit range), where the MARS score will be the same for both the square-root and linear curve.

Figure III-2 – Illustrative Comparison of Linear and Square Root Scaling Functions



Natural Units *(x-axis)*	MARS *(y-axis)*	
Annual Losses	**Square Root**	**Linear**
$1,000	44.7	20
$2,000	63.2	40
$3,000	77.5	60

3. Selection of Weights

SCE selected equal weights (25%) across the four consequences. This creates a 50% total weight on safety consequences (serious injuries and fatalities) in the MARS score. This priority weighting on safety consequences, coupled with the square root scaling functions used for serious injuries and fatalities, make safety a significant component of MARS in this RAMP report.

B. Enterprise Risk Register (ERR) as the Starting Point for RAMP Risk Selection

Similar to the process described in the Settlement, SCE utilized its ERR as a starting point for the process that resulted in the nine risks treated in RAMP.

Due to the timing of completion of the Settlement, SCE was not required to, and did not have sufficient time to, calculate a Safety Risk Score using the full MAVF approach for all ERR risks that have the potential for a Safety impact. In other words, SCE did not calculate MARS values for all risks in its ERR. Further, while SCE conducted in-person outreach sessions with several external stakeholders to describe its risk selection process, it was impossible to hold a formal workshop as indicated in the procedural terms of the Settlement. That is because the Settlement was not yet adopted. SCE will comply with all requirements and take any steps outlined in the adopted Settlement.

C. Use of the Bowtie Diagram

For each of the identified risks included in this RAMP report, SCE utilizes a bowtie methodology, which structures risk as a function of drivers (each with an annual frequency), a discrete risk event, potential outcomes (each has a probability of occurrence), and consequences of those outcomes that are measured in natural units. The bowtie is reflected in Figure I-3 above. Risk is probabilistically quantified for each bowtie as a function of probability and consequence using Monte-Carlo simulations. SCE calculated risk on both an expected value (EV) basis (i.e., the mean), and on a tail-average basis. The Settlement indicates a preference for EV, but allows EV to be supplemented by alternative calculations such as tail-average value.

D. Mitigations Linked to Drivers and/or Outcomes

Controls (existing mitigations) and new mitigations[33] are defined and quantified in terms of their ability to reduce driver frequency, affect the probability of an outcome, and/or reduce the severity of a consequence.

E. Measurement of Risk Reduction and Calculation of Risk Spend Efficiency (RSE)

In this report, SCE uses MARS to measure risk before and after a mitigation is applied, which quantifies how much risk is reduced by the mitigation. The risk reduction is then divided by the dollar cost for the mitigation. This provides an RSE value that can be used to compare the relative risk-reduction efficiency of different mitigations.

F. Other Areas of Note Comparing SCE's RAMP to the S-MAP Settlement

SCE integrated the concept of "dynamic analysis" in a limited fashion by adjusting driver frequency over time to account for expected changes in real-world conditions (e.g., a driver based on an asset failure would increase if certain maintenance programs are not performed).

SCE has endeavored to meet the Settlement's standard for transparency, through actions such as providing the full set of modeling assumptions and outputs upon request, and by providing an intuitive and interactive tool (Power BI) to easily review the results of our analyses.

SCE used historical internal data (e.g., past wire-down frequency) or validated industry data (e.g., FEMA data on ratios of injuries per building fire) as much as possible prior to resorting to internal and external subject matter expertise.

[33] Please note that the Settlement does not distinguish between "controls" or "mitigations."

As discussed previously, SCE has tested the concept of present valuing benefits and costs of risk mitigation activities over their useful lives, in the Hydro Asset Safety chapter. We plan to continue to work with stakeholders to refine this method for potential broader use in future analyses.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Risk Model Overview

Chapter 2

Rosemead CA
November 15, 2018

Contents

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I. Risk Model Overview

A. Introduction

The risk model ("model") utilized in this RAMP report quantifies risk, and the effects that different mitigations have on that risk, using a probabilistic approach. This model enables a more data-driven, risk-informed decision making approach in this RAMP report.

In this chapter, SCE details the mechanics of the model and the process used to calculate Multi-Attribute Risk Scores (MARS), risk reduction, and Risk Spend Efficiency (RSE) for controls and mitigations. This chapter also discusses the innovative reporting capabilities that SCE has developed so that stakeholders can readily view and evaluate the results of the model outputs.

SCE looks forward to further conversations and exchanges with Commission Staff and other stakeholders as they view the results of the model outputs. We plan to discuss this further and answer questions when we hold our upcoming workshop in December of 2018. SCE is available for, and looks forward to, informal collaborative conversations as well.

B. Moving towards a probabilistic approach

This RAMP report represents a significant step forward for SCE in analyzing safety-related risks using probabilistic approaches. This is SCE's first generation RAMP model. Like any quantitative model, the quality of the outputs are largely dependent on the quality of the inputs. Some risk chapters have an abundance of data; others can benefit from capturing and tracking more extensive data. All require judgment in how to apply the data we have to the model parameters. As we build our data sets over time, and as we further refine the model itself, SCE will use the model to increasingly support our risk-informed decision making.

The following sections detail the probabilistic nature of the model.

1. Use of Monte Carlo simulation

The risk model uses a technique called Monte Carlo simulation to achieve the results described above. Here is an explanation of what this is:

> *"Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values – a probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over,*

each time using a different set of random values from the probability functions.

By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis. It tells you not only what could happen, but how likely it is to happen."[1]

2. Modeling distributions and not single data points

Instead of using a single data point to define a model input parameter (e.g., drivers, outcomes, consequences), SCE's model uses statistical distributions for each input parameter. The benefit of doing so is to account for uncertainty in the input data.

For example, assume that a risk driver occurs an average of 10 times per year. SCE will build a distribution around those 10 events. This allows the Monte Carlo simulation to pick points on or around those 10 events to account for variation in the inputs. For example, there could be a small probability (say 5% for illustrative purposes) that there could be 20 events for that driver sometime in the future. A non-probabilistic model would not capture this low-probability event and its associated impact. SCE's model not only captures the various points along the distribution, but also the probability of those events occurring.

Figure I-1 shows a generic risk bowtie. Each component of the bowtie designated with a green box is modeled using a distribution. The choice of distribution used, and its associated parameters (e.g. mean, standard deviation, etc.), is based on historical data, other external data sources, and/or modeling judgment.

For example, Driver #1 could be modeled using a Poisson distribution; Outcome #1 with a Binomial distribution; Reliability impacts for Outcome #1 using an Exponential distribution; and Financial impacts for Outcome #1 using a Lognormal distribution.[2] Although there are many types of distributions in mathematical literature, SCE uses seven of the more

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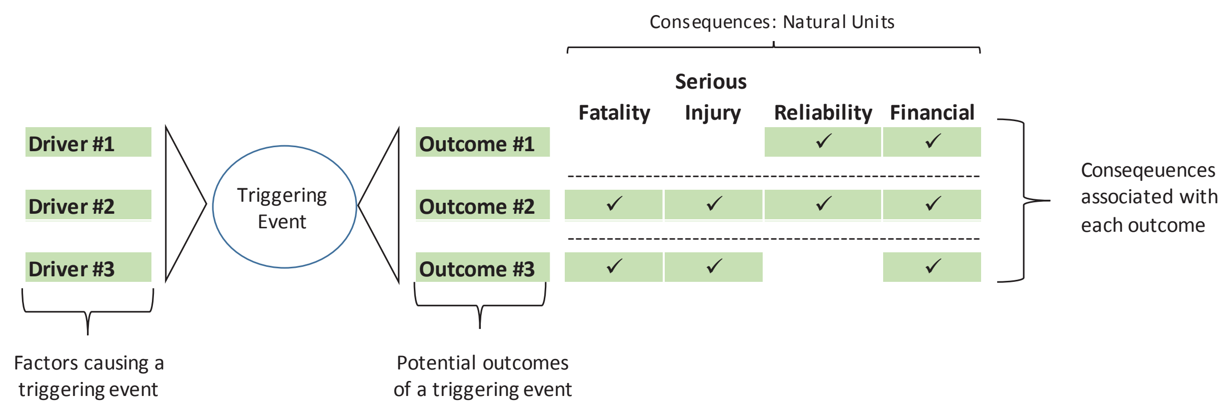
[1] Monte Carlo Simulation information is *available at* http://www.palisade.com/risk/monte_carlo_simulation.asp

[2] Section II of this chapter provides a description of the distributions used in this example.

common distributions when modeling bowtie components in this report. These distributions are described in Section II of this chapter.

Figure I-1 - Illustrative Risk Bowtie

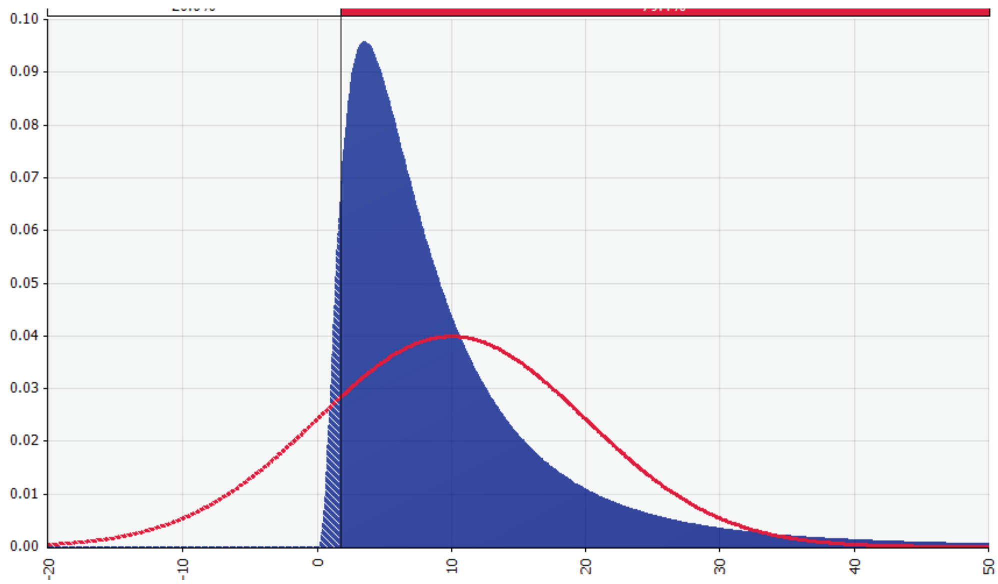


3. Specifying distribution parameters to convey risk

The choice of distributions and associated parameters is critical to the resulting probabilities of each component. Figure I-2 illustrates this by plotting two distributions on the same graph: a normal distribution (red line) and a lognormal distribution (blue shaded region). These distributions are drawn using the same mean (10) and standard deviation (also 10). Even though the shapes of these two distributions are very different, the area under each curve is the same.

The lognormal distribution is visibly “left-skewed,” which results in a greater likelihood that a number less than 10 is picked when the simulation is run. In contrast, the normal distribution presents the shape of a typical bell curve, where the mean (in this case 10) is the most likely number chosen. In addition, even while both the lognormal and normal distributions have the same mean and standard deviation, the lognormal distribution has a fatter “tail” (heading toward the right-hand side of the graph), which results in a greater likelihood that a tail, or extreme event, will occur. Depending on the data being evaluated, different distributions can lead to different model results. The process that SCE used to identify the appropriate distributions to model is detailed in Section III.

Figure I-2 – Lognormal and Normal distributions

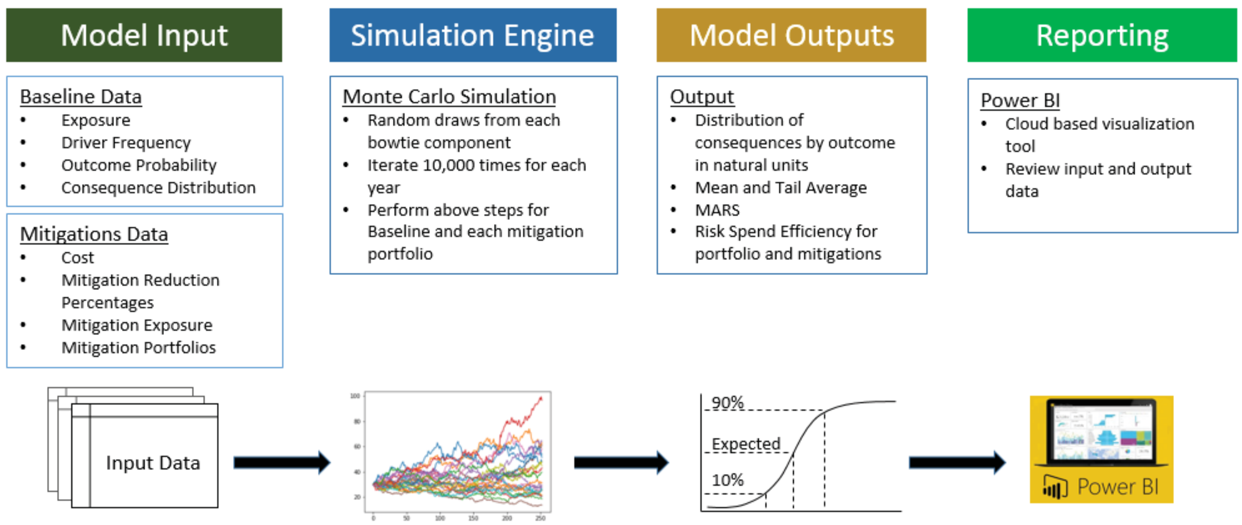


C. Model Architecture

This section provides an overview of how we designed our model, which is summarized below in four stages and shown in Figure I-3:

- Model Inputs
- Simulation Engine
- Model Outputs
- Reporting

Figure I-3 – Model Architecture Overview



1. Model Inputs

In this RAMP report, SCE is evaluating risk over the six-year period from 2018 – 2023. Each data input is required to have specific values for each year, for the applicable years over the 2018-2023 period. The table below defines the key model inputs.

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Table I-1 - Summary of Model Inputs

Inputs	Description
Driver Frequency	Drivers are the factors causing a triggering event. We measure drivers based on the number of times they occur each year.
Triggering Event Frequency (TEF)	The triggering event frequency is the sum of each driver's annual frequency. *Therefore, it is not a model input. Instead, it is a calculated value.*
Outcome Probability	Outcomes are measured by their probability of occurring when the triggering event happens. We measure outcome probability as a percentage; the sum of all outcome percentages equals 100%.
Consequence Distribution Parameters	Consequences measure the type and severity of impacts resulting from the outcome. For each outcome's applicable consequences (serious injuries, fatalities, reliability, and financial), we identify the appropriate distribution type and its associated parameters (e.g. mean, standard deviation). Section III details how distributions and parameters are selected.
Mitigation Reduction Percentage	For each control or mitigation, we determine its effect on reducing one or more drivers, outcomes, and/or consequences. We measure this by calculating a percentage reduction that the control/mitigation reduces each applicable bowtie component by. For example, a mitigation might decrease the annual frequency of a particular driver by 10% and also reduce the financial consequence (associated with a particular outcome) by 20%.
Cost	The annual nominal costs (Capital and O&M) associated with each control/mitigation over the 2018-2023 period are estimated and provided to the model.

Inputs	Description
Exposure	We measure exposure as the scope of the risk that is being analyzed. For example, when measuring the risk of hydro dam failures, the exposure may be the entire portfolio of SCE's high hazard hydro dams, or a subset of those.
Mitigation Exposure	We measure the exposure associated with each mitigation as a percentage of the Exposure input. For example, if the Mitigation Reduction Percentage is 10%, but the Mitigation Exposure is 20%, then the mitigation effectiveness of this mitigation is 10% * 20% = 2%. Some risk chapters explicitly utilize the mitigation exposure input fields, while other risks incorporate the mitigation exposure into the Mitigation Reduction Percentage.

SCE begins the risk evaluation process by identifying and quantifying the inputs described above. These inputs provide the quantitative parameters for each component of the risk bowtie.

2. Simulation Engine

SCE uses the @RISK[3] software plugin for Microsoft Excel to run the Monte Carlo simulations. The next section describes the steps the simulation engine takes to arrive at distributions of results for each risk being evaluated. For reference, in Appendix 1 we provide an illustrative example of how these steps are applied when analyzing a risk.

a. Simulation of Baseline Risk

The simulation starts by systematically "drawing" data points from the distributions of each component of the bowtie. These data points form the basis of one simulation of the risk over the course of a year. The simulation then repeats this drawing 10,000 times, and aggregates the results.

Going from the left side of the bowtie (drivers) to the right side (outcomes and consequences), the simulation specifically performs the following:

[3] *See* Information re: @RISK software *available at* http://www.palisade.com/risk/

1) Simulation of Drivers

A random number is selected from each driver's distribution. These numbers represent the annual frequency for each driver. When added together, these annual driver frequencies result in the annual TEF.

2) Simulation of Outcomes

The TEF number is then probabilistically split into the different outcomes. The simulation uses the binomial distribution[4] to simulate the number of events associated with each outcome. For example, if the TEF is 100, and the outcome probability for Outcome #1 is 10%, then probabilistically the number of events from the TEF allocated to Outcome #1 is 10.

3) Simulation of Consequences

Each outcome is associated with one or more consequences (serious injury, fatality, reliability, and financial). In the example above, Outcome #1 results in reliability and financial consequences. If Outcome #1 occurs 10 times, then the model will draw 10 numbers from the reliability distribution and add those numbers together. In addition, it will draw 10 numbers from the financial distribution and add those numbers together. This process will continue for all other outcomes. For example, since Outcome #2 results in four consequences, it will draw samples from each of the four consequence distributions.

The model has now, for this one draw, calculated the overall impact for each of the consequences associated with each outcome. This process is repeated 10,000 times, for each year, so that each consequence and outcome combination will have a collection of 10,000 numbers for each year. This is what we refer to as a distribution of results. This distribution of results is specific to each consequence attribute in terms of natural units (e.g. customer minutes of interruption (CMI) for reliability, dollars for financial, etc.).

---

[4] The binomial distribution is a discrete distribution where the random variable chosen (the output) is a positive integer and is used in the Outcome portion of the bowtie. It is a probability distribution of the number of successes in a sequence of *n* independent trials based on a probability of success (*p*). In the bowtie, the *n* would represent the TEF of each scenario and the *p* is the outcome percentage. *See* Section II for more information.

b. Simulation of Mitigated Risk

Next, the model simulates the effects of the controls and mitigations on the baseline risk. This is done in three steps:

- Mapping individual mitigations to each portfolio;
- Developing an updated set of model inputs based on the mitigations;
- Running the same Monte Carlo simulation process as performed for the baseline risk, for each of the three mitigation portfolios.

1) Mapping of individual mitigations to each portfolio

Controls and mitigations are bundled together into portfolios. These portfolios represent collective options for addressing the risk. In accordance with RAMP requirements, SCE has put together three portfolios: Proposed Plan, Alternative Plan #1, and Alternative Plan #2. Table I-2 illustrates how this general mapping occurs.

Table I-2 – Mapping of individual mitigations to portfolios

	Proposed	**Alternative 1**	**Alternative 2**
M1 -Mitigation 1	X	X	X
M2 -Mitigation 2		X	X
M3 -Mitigation 3		X	
M4 -Mitigation 4	X	X	
M5 -Mitigation 5			X

In this example, the Proposed Plan consists of two mitigations: M1 and M4.

2) Revised set of mitigation inputs

Each mitigation plan is then evaluated based on its aggregate effect on the baseline risk inputs. This requires evaluating not only the effect that each control or mitigation has on the baseline risk, but the effects that each control or mitigation have on each other.

As discussed previously, each mitigation can influence any or all of the following baseline risk inputs: 1) driver frequency, 2) outcome probability, and/or 3) consequence impact. For example, M1 could reduce the frequency of Driver #1 by 10%, and also reduce the mean of the fatality consequence distribution for Outcome #2 by 20%.

When mitigations are compiled into a mitigation plan, we must understand how one mitigation may affect another. For example, in the Proposed Plan shown above, there are two mitigations: M1 and M4. Suppose the baseline driver frequency for Driver #1 is 200, and M1 reduces the frequency of Driver #1 by 10%. The new "mitigated" driver frequency based on the effect of M1 would be 200*(100% - 10%) = 180, or a 10% reduction to the frequency of Driver #1.

However, M4 may also reduce the frequency of Driver #1. In this scenario, M4 will reduce the frequency of Driver #1 by 20%. This 20% reduction is now to the reduced driver frequency after M1 has been accounted for (180). As such, the new frequency for Driver #1 now equals: 180*(100% - 20%) = 144. The aggregate effect of both M1 and M4 results in a 28% reduction in the frequency of Driver #1. This is in contrast to a 30% reduction if we were to simply add the reductions from M1 (10%) and M4 (20%).

The key concept that the model implements is that mitigation reduction percentages are compounded when used to compute the mitigated parameter.[5] Because of compounding, the same mitigation can have different risk reduction values, depending on the other mitigations in the portfolio. This compounding approach is applied to each baseline risk input, and for each of the three mitigation plans.

3) Rerun using the revised set of mitigation inputs

For the next step, we now run each mitigation plan (separately) through the model using the new mitigated input values. For example, for the Proposed Plan simulation, the input for Driver #1 will now be set at an annual frequency of 144, instead of 200 as used in the baseline risk simulation. As with the baseline risk simulation, each mitigation plan is simulated 10,000 times for each year. Similarly, the simulation produces a distribution of results specific to each consequence.

[5] The order of how the mitigation percentage reductions that are applied to the baseline risk has no impact. For example, whether the 20% or the 10% is applied first, the final mitigated frequency number will still be 144 in this example.

3. Model Output

After the model simulations are completed for both the baseline risk and the three mitigation plans, we perform certain post-processing calculations to aggregate simulation results, convert to MARS, and derive RSE values.

a. Aggregation

The model calculates the overall mean and tail-average[6] (TA) for each consequence for each year. For example, as shown previously, there are three outcomes (Outcome #1, Outcome #2, and Outcome #3) that result in financial consequences. The model calculates the mean of the financial consequence for each of the outcomes. This step will add those together to provide an aggregated financial consequence value. This will similarly be done for the TA results.

At the end of this process, there will be an overall mean and TA for each of the consequences for each year. This process is repeated for baseline risk and for each of the mitigation plans.[7]

b. MARS

SCE then converts the mean and TA of each consequence, in natural units, to a common unit-less metric so that different consequence results can be added together to show total risk levels. This is known as MARS.[8] Table I-3 is a sample calculation example that converts natural units, on a mean basis, to MARS. The same steps would be taken to convert the TA, in natural units, to MARS.

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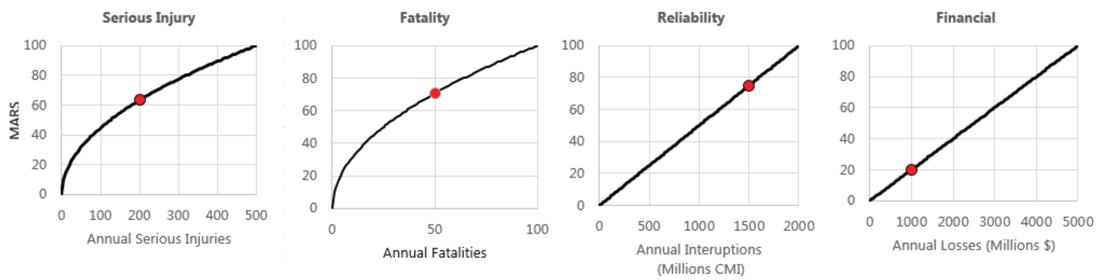
[6] Please refer to RAMP Overview Chapter, Appendix 1 (RAMP Summary Results) for additional discussion on using mean and tail-average results.

[7] *See* Appendix 1 of this Chapter for an additional example of this.

[8] Please refer to RAMP Overview Chapter for further discussion on how SCE arrived at the MARS approach and how we developed the placeholder values for its component parts.

Table I-3 – Example: Conversion from Natural Units to MARS

		Consequences (Natural Units)			
		Serious Injury	Fatality	Reliability (CMI)	Financial ($)
a	Mean	200	50	1.5 Billion	1 Billion
		MARS Calculation			
b	Weights	25%	25%	25%	25%
c	Scaled Score	63.25	70.71	75.00	20.00
d=b*c	Apply Weights	15.81	17.68	18.75	5.00
		Consequences (MARS Units)			
		Serious Injury	Fatality	Reliability	Financial
		15.81	17.68	18.75	5.00
	Overall MARS (out of 100)	57.24			



- Row (a) presents the overall mean for each of the four consequences.
- Row (b) shows the MARS weights for each of the four consequences. Each consequence is assigned an equal weight of 25%.
- Row (c) calculates the scaled score, in MARS, of the mean (in natural units) for each of the four consequences. The scaling curve (black line) represents the relationship between the x-axis (in natural units) and y-axis (MARS).[9] For example, the mean of the reliability consequence is 1.5 billion CMI. We find 1.5 billion CMI on the x-axis, identify the point on the curve directly vertical to it (see red dot), and determine the y-intercept (which in this example is 75 MARS).
- Row (d) now applies the weight in Row (b) to the scaled score in Row (c) to arrive at a scaled and weighted MARS score for each consequence. Using the same reliability example, a 25% weight is applied to the MARS score of 75, which equates to a scaled and weighted MARS score of 18.75.

[9] In this RAMP report, SCE uses square root scaling functions for the serious injury and fatality consequences, and linear scaling functions for the reliability and financial consequences. More detail on why these scaling functions were chosen for each consequence can be found in Appendix 2 of Chapter 1 (RAMP Overview).

The steps above for the MARS conversion from natural units for reliability can by summarized by the following equation:

$$\frac{1.5\ Billion}{2\ Billion} * 100 * 25\% = 18.75$$

In this equation, 1.5 billion is the number of CMI, 2 billion is the top end of the reliability range, and 25% is the MARS weighting.

The MARS for each consequence are added together to arrive at an overall MARS for each risk or mitigation plan. In this example, this risk has an overall MARS score of 57.24. The highest MARS score is 100.

c. Risk Spend Efficiency

The RSE is a metric to determine the cost efficiency of a mitigation or mitigation plan at reducing risk. The RSE calculation is:[10]

$$RSE = \frac{Baseline\ MARS - Post\ Mitigation\ MARS}{Expenditures}$$

In this RAMP report, SCE calculates the total RSE for each control and mitigation over the six-year 2018-2023 RAMP period. We also calculate the RSE for each of the three mitigation Plans, both by year and over the entire RAMP period.

It is important to note that because the maximum MARS score is 100, and because most of our controls and mitigations require much more than $100 to execute, the RSE scores are all small numbers (mostly less than one). This is purely a product of the RSE math equation, and bears no indication to the actual efficiency of a mitigation. Most importantly, RSE is a relative metric – it is most meaningful when used to compare controls and mitigations within a RAMP chapter. Therefore, whether the RSEs are less than one or greater than one

[10] Due to the number of decimals places created by the RSE calculation, SCE scales the RSE by one million, to show the RSE in terms of millions of dollars.

million, there is no difference since the magnitude of the RSE is comparable only on a relative basis between controls and mitigations. Table I-4 provides an illustrative comparison of this.

Table I-4 – Illustrative Comparison of Relative RSE Scores at Different Magnitudes

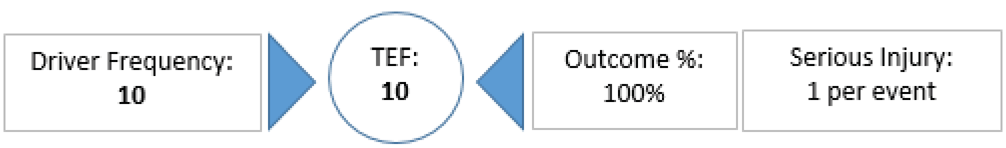
	RSE of Control A	RSE of Control B	Difference (B to A)
Scenario 1	1,000	2,000	100%
Scenario 2	0.001	0.002	100%

1) Individual Mitigation Risk Reduction

The model provides RSE results for each of the three mitigations plans. However, we must perform a few additional calculations to derive RSE for each control and mitigation. We must allocate the risk benefits from the mitigation plans to the individual controls and/or mitigations. We illustrate how this is done through the following example.

Consider the simplistic bowtie example in Figure I-4, which contains one driver, one outcome, and one consequence.

Figure I-4 – Simple Bowtie (Baseline Risk)



The total number of serious injuries for this risk is 10 (10 TEF x 1 Serious Injury per Event = 10 Serious Injuries). The baseline MARS is therefore:

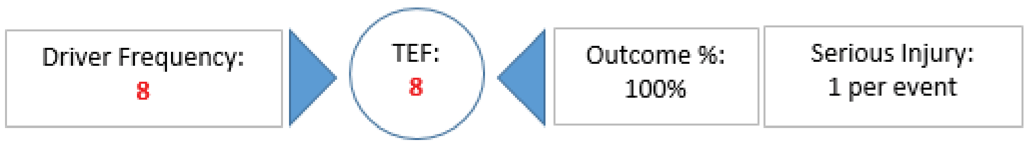
$$\sqrt{\frac{10}{500}} * 100 * 25\% = 3.54$$

In this equation, 10 is the number of serious injuries, 500 is the MARS range, 25% is the MARS weight, and the square root is used because of the square root scaling curve used for serious injuries in this RAMP report.

2) Single Mitigation Scenario

Now, consider a scenario where there is one mitigation (M1) which reduces the driver frequency by 20%, as shown in Figure I-5, at a cost of $15 million. M1 reduces the driver frequency to 8, (10 x (100% - 20%)).

Figure I-5 – Single mitigation scenario



The number of serious injuries after M1 is deployed is now 8. Therefore, the *mitigated MARS* is:

$$\sqrt{\frac{\mathbf{8}}{500}} * 100 * 25\% = 3.16$$

The portfolio RSE is:

$$RSE\ (Portfolio) = \frac{3.54 - 3.16}{\$15M} = 0.025$$

The risk reduction in this scenario for M1 is [3.54 (baseline risk) – 3.16 (mitigated risk)] = 0.38. Since there is only one mitigation, M1 has the same RSE as the portfolio, namely 0.025.

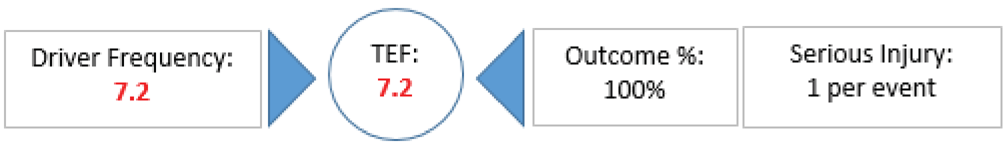
Importantly, because of the non-linearity of the serious injury scaling curve, a reduction from 10 to 8 serious injuries *will not* be the same MARS as a reduction from 5 to 3 serious injuries.

3) Multiple Mitigations Scenario

Here is a second scenario which introduces a mitigation portfolio containing two mitigations (M1 and M2). M1 is the same as above (provides a 20% reduction to the driver frequency at a cost of $15M). M2 also reduces the driver frequency, but by 10% and at a cost of $10 million.

Considering the driver reductions for both mitigations, the new mitigated driver frequency is 7.2, calculated using the compounding technique described earlier in this chapter: (TEF) * (1 – M1 Reduction) * (1 – M2 Reduction). This is calculated as follows: 10*(1-10%)*(1-20%) = 7.2. This is illustrated in Figure I-6.[11]

Figure I-6 – Multiple Mitigation Scenario



The number of serious injuries after applying the two mitigations is now 7.2. The mitigated MARS is now 3:

$$\sqrt{\frac{7.2}{500}} * 100 * 25\% = 3$$

The portfolio RSE is now 0.022:

$$RSE\ (Portfolio) = \frac{3.54 - 3}{\$10M + \$15M} = 0.022$$

The total risk reduction of the portfolio is (3.54 – 3) = 0.54. To calculate the RSE for each mitigation (M1 and M2), we must now allocate this risk reduction back to the two mitigations. To do this, we consider how much M1 contributed to the total risk reduction, on a proportional basis, versus M2, based on their respective mitigation reduction percentages:

$$M1\ risk\ reduction\ contribution = \frac{M1\ Reduction\ \%}{(M1\ Reduction\ \%\ + M2\ Reduction\ \%)} * Total\ Risk\ Reduction$$

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[11] Please note that in the actual model, the output of a driver and outcome distribution will be a discrete number and not a decimal. This is only an illustrative example.

$$M1\ risk\ reduction\ contribution = \frac{20\%}{(20\% + 10\%)} * 0.54 = \mathbf{0.36}$$

Due to the compounding effect, the risk reduction for M1 in this multiple-mitigation example (0.36) is different than the risk reduction for M1 in the single-mitigation example (0.38).

Using the same method, we calculate the risk reduction provided by M2 in this example:

$$M2\ risk\ reduction\ contribution = \frac{10\%}{(20\% + 10\%)} * 0.54 = \mathbf{0.18}$$

Now that we know the risk reduction for each mitigation, we can calculate their respective RSE, as follows:

$$RSE\ (M1) = \frac{0.36}{\$15M} = 0.024$$

$$RSE\ (M2) = \frac{0.18}{\$10M} = 0.018$$

This concept of proportionally allocating the benefits back to the individual mitigations is carried throughout the bowtie, for drivers, outcomes, and consequences. When risks have multiple drivers, outcomes, and consequences, as well as mitigations which can affect any of those bowtie components, then the level and number of proportionality calculations can rise quickly.

4. Reporting

The model and post-processing calculations that SCE employs produce a large volume of data. These data are important to have so that we can understand and analyze each aspect of each risk. However, it can be cumbersome to sort and mine through all of this data, across all nine risk chapters, using standard spreadsheets and static files.

As such, SCE used an interactive reporting tool to transform this raw data into easily digestible information. This is done through Power BI, a Microsoft cloud-based business analytics software that harnesses the key strengths of Microsoft Excel (analytical capabilities, charting capabilities) and PowerPoint (presentation capabilities). SCE used this tool to design interactive reports and dashboards for users to better understand the risk analysis, including but not limited to:

- Results that can be toggled between mean or tail-average;
- Results that can be toggled between natural unit or MARS;
- Baseline risk inputs;
- Control and mitigation effects on the bowtie;
- Control and mitigation mapping to mitigation plans;
- Risk reduction and RSE for each control/mitigation, and for each mitigation plan;
- Comparative results across the nine risks;

SCE pulls data from the models into Power BI. We then used Power BI to help calibrate within and across the RAMP risks, identify trends and outliers, quickly spot and correct modeling and transposition errors, and serve as our "source of truth" when populating relevant charts and tables used throughout this RAMP report.

SCE believes it is beneficial to share this tool with stakeholders to help them understand and evaluate the results of our RAMP report. Because Power BI is cloud-based, no additional software is needed other than an internet browser. To request access to this tool, please follow the instructions found in the workpapers for Chapter 1 (RAMP Overview).[12] In addition, a user guide for how to navigate the RAMP Power BI tool is also provided in the workpapers for Chapter 1 (RAMP Overview).[13] Please note that Power BI is a one-way tool.

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[12] Please refer to WP Ch. 1, pp. 1.5 – 1.8 *(RAMP Power BI Access Form & Sign-up Instructions)*.

[13] Please refer to WP Ch. 1, pp. 1.9 – 1.40 *(RAMP Power BI User Guide)*.

Users cannot change the data, but can download the data associated with each chart/table and conduct their own analysis.

D. Summary of Risk Modeling Lessons Learned[14]

The model discussed in this chapter is SCE's first-generation RAMP risk model. Accordingly, we learned many things as we developed and applied it for risk analysis. We believe we have meaningfully advanced our probabilistic modeling capabilities using this model. However, there are areas we have identified for further consideration as we look to continuously improve our capabilities.

1. Undervaluing risk reduction and RSE in mitigations that span multiple risks

As discussed in the RAMP Overview chapter, mitigations can benefit multiple risks. For purposes of this RAMP report, the model is set up to evaluate each risk independently. Similarly, the model we developed can only calculate the effect each mitigation has on one risk at a time. This means that the total risk reduction benefits, and associated RSE, of each of these mitigations are not fully captured within each risk chapter.

Whenever this occurs in this RAMP report, SCE models the mitigation's effect on each risk independently within each risk chapter. However, we include the full cost of the mitigation in each chapter. This has the effect of *artificially lowering the RSE by including the full cost of the mitigation, but only part of the full benefits.*

SCE will consider how to address this issue on a going-forward basis.

2. Degrees of confidence in modeling mitigation effectiveness

Whereas SCE uses distributions to model the baseline risk input parameters (driver frequency, outcome probability, consequence impacts), we use a single percentage to model the risk reduction associated with each mitigation's effect on each input parameter. In modelling the uncertainty or confidence level of our baseline risk inputs, we can vary the width of each distribution; for example, a larger width (standard deviation) means more uncertainty, and smaller width (standard deviation) means less uncertainty.

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[14] Please refer to WP Ch. 2, pp. 2.1 – 2.3 (*Risk Model Lessons Learned – Additional Detail)* for additional detail on these Lessons Learned.

As SCE collects more data to support fitting a distribution, this concept could be applied to the mitigation reduction percentage inputs as well. For example, if the mitigation reduction percentage is set at 15%, but there is high confidence that this estimate is accurate, then the standard deviation assigned to this particular mitigation would be small (for example, +/- 2%). But if the confidence level in this estimate is low, the standard deviation could be much higher, for example +/- 10%). This framework would thus capture the uncertainty around the mitigation's effectiveness factor. SCE may consider future updates to our model to account for this potential improvement.

3. Identifying control and mitigation impacts for each year in the RAMP period

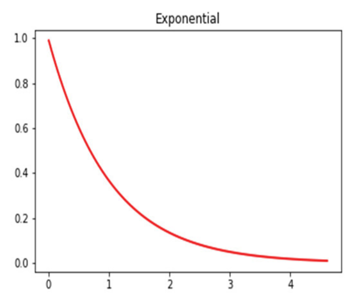
As previously discussed, the model produces RSE by year for each mitigation plan (Proposed, Alternative #1, Alternative #2). However, the model does not directly produce RSE by year at the individual control or mitigation level. We currently need to take the results of the model at the Plan level, and allocate them to each control and mitigation. During this post-processing effort, we calculate the risk reduction and RSE of each individual control and mitigation over the six-year 2018 – 2023 period. We have not yet built in the capability to further allocate these individual control or mitigation benefits on an annual basis. We understand that it may be beneficial to identify the specific risk reduction benefits and RSE of individual controls and mitigations on an annual basis, rather than in aggregated form over the six-year period. Accordingly, we plan to consider how we might incorporate those calculations into future iterations of the model.

II. Distribution Types Used in SCE's RAMP Report

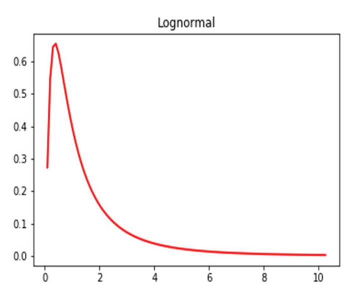
The figures below show the probability density function (PDF) of the distributions that are used in the model. The PDF is used to determine the probability that a random variable lies between two values. The higher the peak, the higher percentage a random variable will be drawn from that point.

There are two categories of distributions used in this RAMP report: continuous and discrete. Random variables drawn from a continuous distribution can assume an infinite number of different values, while random variables drawn from a discrete can only assume a finite number of values (in this case integers).

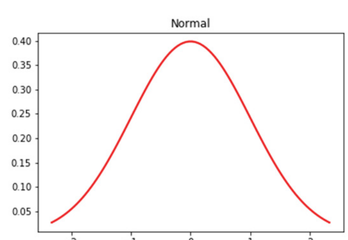
A. Continuous Distributions



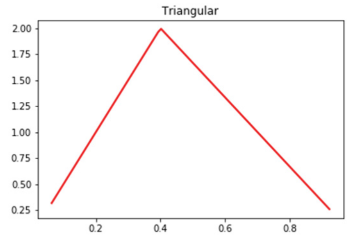
The exponential is often used to represent decay, where the majority of values are in the lower range (near zero) and has a tail with larger losses. It has only one parameter, the mean.



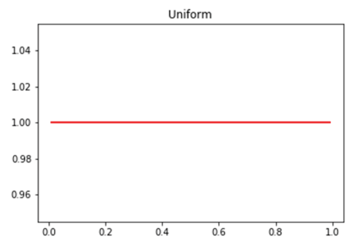
The lognormal distribution, unlike the normal distribution, is bounded on the left side by zero (so only positive values) with a tail similar to the exponential distribution. It has two parameters: a mean and a standard deviation.



The normal distribution is a symmetrical bell-shaped curve, with minimum values that are not bounded by zero. It has two parameters: a mean and a standard deviation.

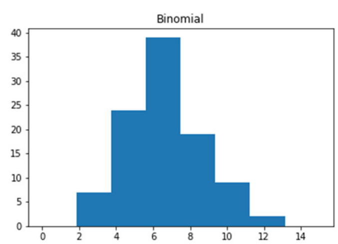


The triangular distribution is bounded by a minimum and maximum value. The tip of the triangle is the mode (or the highest frequency value). Therefore, the probability that a random value that is chosen near this tip is the highest. It has three parameters: a mininum, a maximum, and mode.

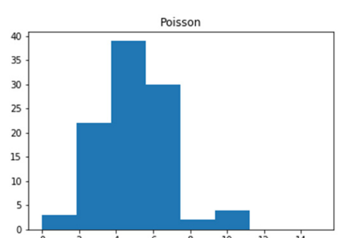


The uniform distribution is bounded by a minimum and maximum. The probability that a random value is selected between the minimum and maximum is the same. It has two paramters: a minimum and maximum value.

B. Discrete Distributions



The binomial distribution is a discrete distribution where the random variable chosen (the output) is a **positive integer** and is used in the **Outcome** portion of the bowtie. It is a probability distribution of the number of successes in a sequence of *n* independent trials based on a probability of success (*p*). In the bowtie, the *n* would represent the TEF of each scenario and the *p* is the outcome percentage.



The poisson distribution is also another discrete distribution where the random variable chosen is a **positive integer** and is used in the **Driver** portion of the bowtie since the Trigger Event Frequency should be a positive integer number instead of a number with decimals (which would be the output of continuous distributions). It is used to describe the number of "events" in some time interval (i.e., annual).

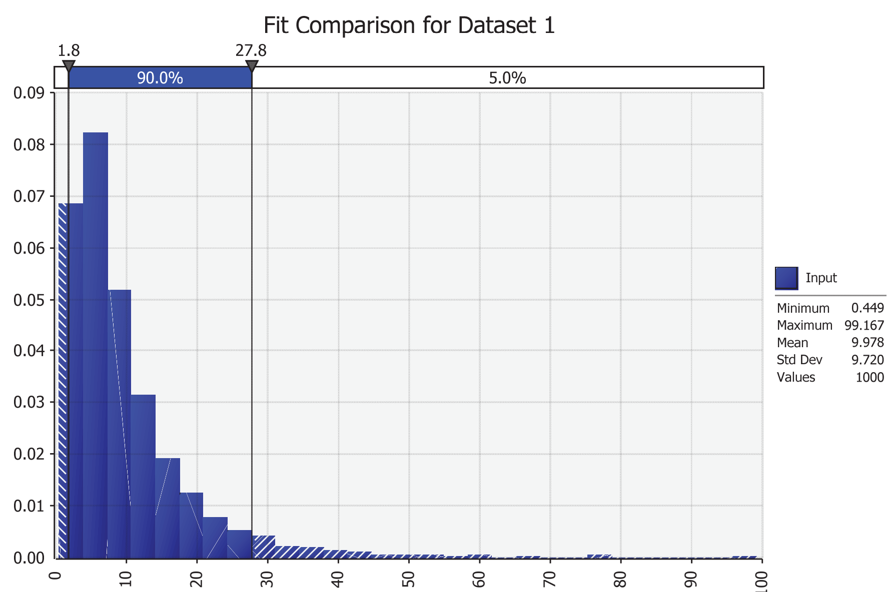
III. Distribution Fitting Process

This section describes how distributions were chosen for the consequences modeled in each risk chapter. The specific distributions used within each chapter are provided in each chapter's respective workpapers.

Most statistical software packages include a "distribution fitting function" which evaluates a list or time series of numbers (e.g., historical data) and recommends a distribution type which best fits the inputs. The @RISK simulation software includes this type of function. SCE used this distribution fitting function as a starting point in determining the appropriate distribution to use for each consequence. We then evaluate the results and make adjustments as necessary to best reflect the risk being evaluated.

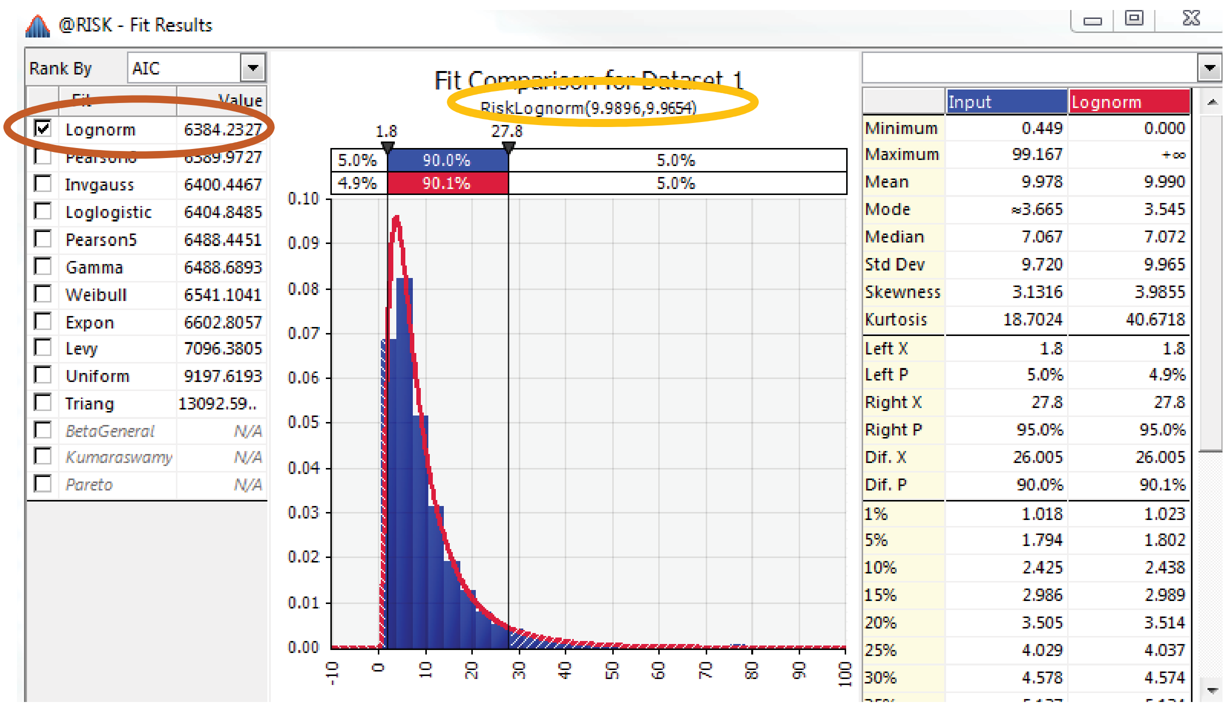
The distribution fitting function is illustrated in the following example: 1,000 events resulting in CMI are provided to the model – these data are plotted as a histogram in Figure III-1. There are a few key statistics displayed on the right-hand side of the histogram, such as the mean (which is ~10).

Figure III-1 – Histogram plot of sample data



We then run the @RISK distribution fitting function to determine the best fit distribution and associated parameters to model this data. A screenshot of this function is shown in Figure III-2.

Figure III-2 – Sample Distribution Fitting Function



The @RISK function chose the Lognormal distribution as the best fit (see top left section where Lognorm is at the top of the list). In addition to choosing the best fit distribution type, the function also chooses the best fit distribution parameters (such as mean and standard deviation).

IV. Appendix 1: Simulation Example

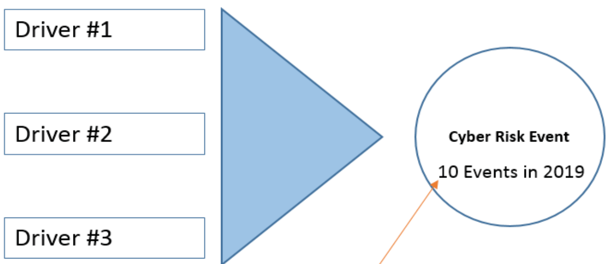
This appendix provides an illustrative example of how the risk model works.

Step 1

Drivers - Inputs

Illustrative Example

Driver(s) will determine the frequency of the Risk Event (i.e. Cyber intrusion) per year



If the ***average*** yearly frequency of the "Cyber Risk Event" is 10 in 2019, then the sum of the frequency for Driver(s) #1 + #2 + #3 must also be 10 in 2019.

	2019	2020	2021	2022
Driver #1	5	5	3	7
Driver #2	3	6	2	2
Driver #3	2	7	1	3
Risk Event Count	10	18	6	12

Inputs

Each Driver is independent (no correlation)

Step 2:

Driver –> Risk Event Calculation

For each Driver and Monte Carlo trial, draw a random number from a Poisson distribution (outputs an integer number) given the frequency.

See slide 1, 2019 Column for Driver Frequency

Sample draws for 2019

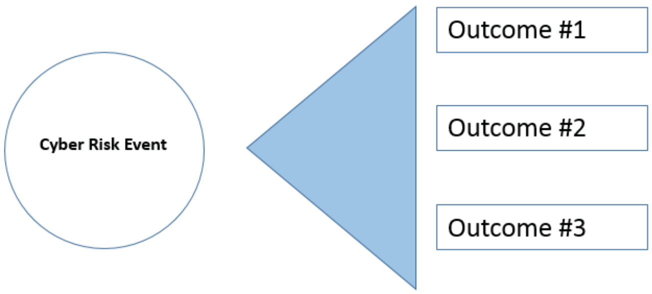
Trials	Driver #1 Freq : 5	Driver #2 Freq : 3	Driver #3 Freq : 2	Total count of Risk Event
1	7	2	1	10
2	5	5	3	13
3	5	2	3	10
4	3	0	2	5
5	6	1	2	9
....	...	...	...	...
10,000	4	4	1	9
Average	5	3	2	10

Random Draws

Step 3:

Outcomes - Inputs

Given that ***x*** "Risk Events" have been triggered for a given year (see previous slide), determine how many instances of each outcome will occur



The yearly percentage of Outcome(s) #1 + #2 + #3 will be equal to 100%

%	2019	2020	2021	2022
Outcome #1	60%	40%	10%	25%
Outcome #2	30%	40%	10%	25%
Outcome #3	10%	20%	80%	50%
TOTAL	100%	100%	100%	100%

Inputs

Step 4:

Risk Event -> Outcome Calculation

Given the "Total count of Risk Event" for each trial, draw from a binomial distribution for each Outcome given its probability of occurring. A binomial distribution is used because it takes as input A) sample size and B) probability of success.

Trials	Total count of Risk Event (from slide 2)	Outcome #1 Occurrence: **60%**	Outcome #2 Occurrence: **30%**	Outcome #3 Occurrence: **10%**	Total
1	10	7	4	0	11
2	13	9	4	2	15
3	10	5	2	3	10
4	5	4	2	0	6
5	9	4	2	1	7
....	...	...	...	...	
10,000	9	7	4	0	11
Average	10	6	3	1	10

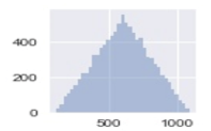
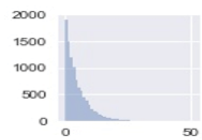
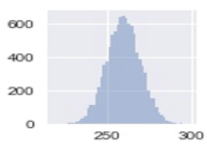
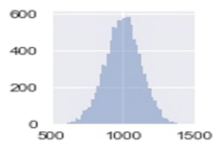
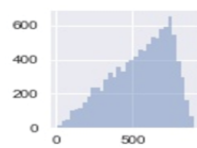
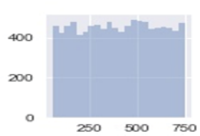
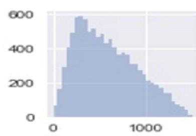
For trial #1, Outcome #1 will happen **7** times given that the Risk Event occurs 10 times in a particular year

Note: The total of each row will not always equal the Risk Event count of each trial. However, on average, it will (see bottom row).

Step 5:

Outcome -> Consequence Mapping

Each Outcome is mapped to Consequences. This mapping is associated with a distribution type (i.e. normal, uniform, etc..) and the distribution parameters (such as mean, standard deviation, etc...). The selection of distribution will primarily be based on historical SCE or other utilities data, informed or potentially adjusted by SME input. These distributions are based on a ***per event*** basis.

	Financial	Reliability	Serious Injury
Outcome #1	[NONE]		
Outcome #2			
Outcome #3			[None]

Step 6:

Financial Consequence Calculation ($)

Financial : Based on the mapping table (step 5), draw from the appropriate [Outcome | Consequence] distribution type the number of times per each outcome/trial and then sum the numbers.

Trial	Total count of Risk Event	Outcome #1	**Financial ($) Consequence for Outcome #1**	Outcome #2	**Financial ($) Consequence for Outcome #2**	Outcome #3	**Financial ($) Consequence for Outcome #3**
1*	10	7	**N/A (See upper left cell in Slide 5)**	4	1,077	0	0
2	13	9		4	1,074	2	491
3	10	5		2	528	3	786
4	5	4		2	497	0	0
....	...	...		...	...	...	
10 **K**	9	7		4	1,317	0	0

*** See first row from step 4**

Financial Consequence #2, Trial 1: Draw 4 numbers from the Normal Distribution associated with Outcome #2 and Financial Consequence [See step 5]. The 4 numbers are 259, 277, 262, 279. The sum of these numbers is **1,077**.

Financial Consequence #3, Trial 2: Draw 2 numbers from the Uniform Distribution associated with Outcome #3 and Financial Consequence [See step 5]. The numbers are 165 and 326. The sum of these numbers is **491**.

Step 7:

Reliability Consequence Calculation (CMI)

Reliability: Based on the mapping table (step 5), draw from the appropriate [Outcome | Consequence] distribution type the number of times as listed and then sum the numbers.

Trial	Total count of Risk Event	Outcome #1	Reliability (CMI) Consequence for Outcome #1	Outcome #2	Reliability (CMI) Consequence for Outcome #2	Outcome #3	Reliability (CMI) Consequence for Outcome #3
1*	10	7	3,869	4	3,695	0	0
2	13	9	5,802	4	3,937	2	491
3	10	5	3,444	2	1,168	3	786
4	5	4	2,925	2	2,010	0	0
….	…	…		…	…	…	
10 K	9	7	3,666	4	3,797	0	0

*** See first row from step 4**

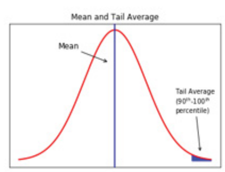
Reliability Consequence #1, Trial 4: Draw 4 numbers from the Triangle Distribution associated with Outcome #1 and Reliability Consequence [See step 5]. The 4 numbers are 525, 564, 1000, 836. The sum of these numbers is **2,925**.

Reliability Consequence #2, Trial 3: Draw 2 numbers from the Normal Distribution associated with Outcome #2 and Reliability Consequence [See step 5]. The numbers are 1,067 and 101. The sum of these numbers is **1,168**.

Step 8:

Aggregating Consequences

- Calculate the Mean and Tail Average (TA) from the output (green columns in slides 6,7) for each Consequence and Outcome.
  - Mean: Average the output
  - TA: Average the worst 10% of the output
- Overall Mean
  - Add the mean for each of the outcomes associated for each consequence
- Overall TA
  - Add the TA for each of the outcomes associated for each consequence



	Financial	Reliability	Serious Injury
Outcome #1	[None]	Mean = 1,500 TA = 3,000	Mean = 10 TA = 20
Outcome #2	Mean = 1,500 TA = 2,500	Mean = 5,000 TA = 6,000	Mean = 20 TA = 25
Outcome #3	Mean = 3,000 TA = 5,000	Mean = 800 TA = 2000	[None]

Overall Mean and Tail Average

	Financial	Reliability	Serious Injury
Mean	**4,500** = 1,500 + 3,000	**7,300** = 1,500 + 5,000 + 800	**30** = 10 + 20
Tail Average	**7,500** = 2,500 + 5,000	**11,000** = 3,000 + 6,000 + 2,000	**45** = 20 + 25

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Safety Culture & Compensation Policies Tied to Safety

Chapter 3

Rosemead CA
November 15, 2018

Contents

Tables

Figures

I. Safety Culture and Performance

Southern California Edison (SCE) is committed to delivering safe, reliable, affordable and clean energy to its customers. Safety is our top priority, and part of that is making sure that we empower employees with the knowledge, motivation, and means to make safe choices. SCE is also committed to collaborating with our contractors to strengthen safe work practices and educating the public to avoid hazards associated with our electrical grid.

SCE has markedly improved in some aspects of safety performance. Our Days Away, Restricted or Transferred (DART)[1] rate is steadily declining. However, serious injuries and fatalities continue to occur. The majority of serious injuries and fatalities over the past decade have occurred because of human error, and not the failure of equipment, policies, or programs. Based on the results of our safety culture assessments, we believe that the next step in improving safety requires improving our underlying culture. This conclusion is also supported by industry success stories and academic literature spanning other industries and disciplines.

Research and standards published by safety governing bodies such as the Institute of Nuclear Power Operations (INPO) and the Occupational Health and Safety Administration (OSHA) establish that a strong safety culture is a prerequisite to positive safety performance. An organization's safety culture refers to a shared set of beliefs, rules, and values around safety upheld by an organization and its employees. To better understand our current safety culture and measure its ongoing improvement, SCE is leveraging a research-based safety culture maturity model. This maturity model is comprised of five sequential levels that correspond with observable safety behaviors. These five levels are described below and illustrated in Figure I-1.

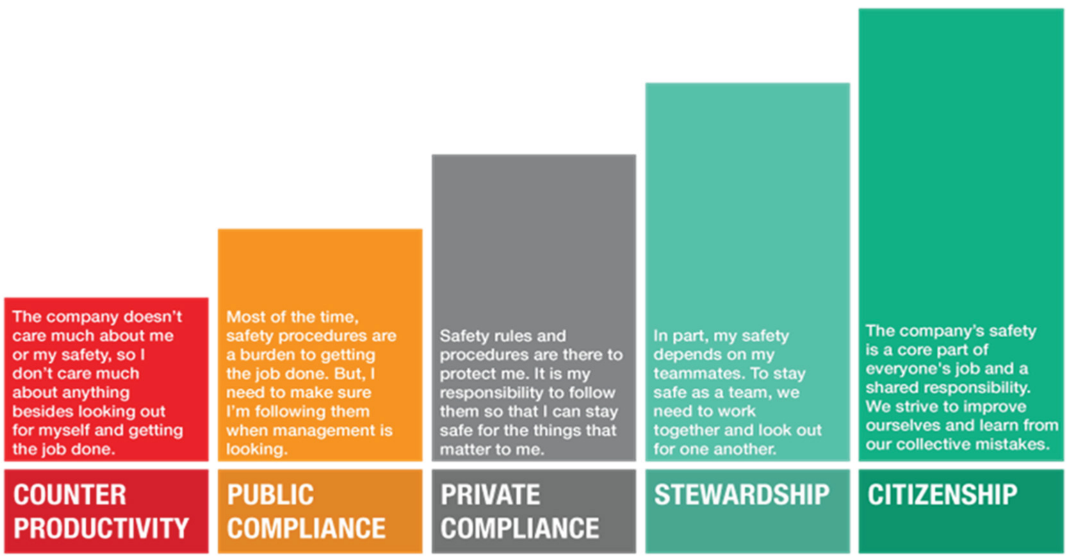
1. Counter Productivity – "safety doesn't matter much around here";
2. Public Compliance – "follow procedures when management is looking;"
3. Private Compliance – "I value my safety, so I follow the rules;"
4. Stewardship – "to stay safe as a team, we need to look out for one another;"

[1] DART means "days away, restricted or transferred." DART is a safety metric used by the Occupational Safety and Health Administration (OSHA) to show how many workplace injuries and illnesses caused the affected employees to remain away from work, restricted their work activities or resulted in a transfer to another job as they were unable to do their usual job within a calendar year. The DART rate helps the employer identify safety items and issues in the workplace.

5. Citizenship – "we strive to improve ourselves as individuals and together as a company."

Each level of safety behavior maturity in Figure I-1 below aligns with particular characteristics of organizational safety culture, including employee values, beliefs, and attitudes. As a result, by observing employees' behaviors and other tangible signs of safety culture, SCE can determine its level of safety culture maturity and develop specific strategies to improve.

Figure I-1 – Safety Culture Maturity Model



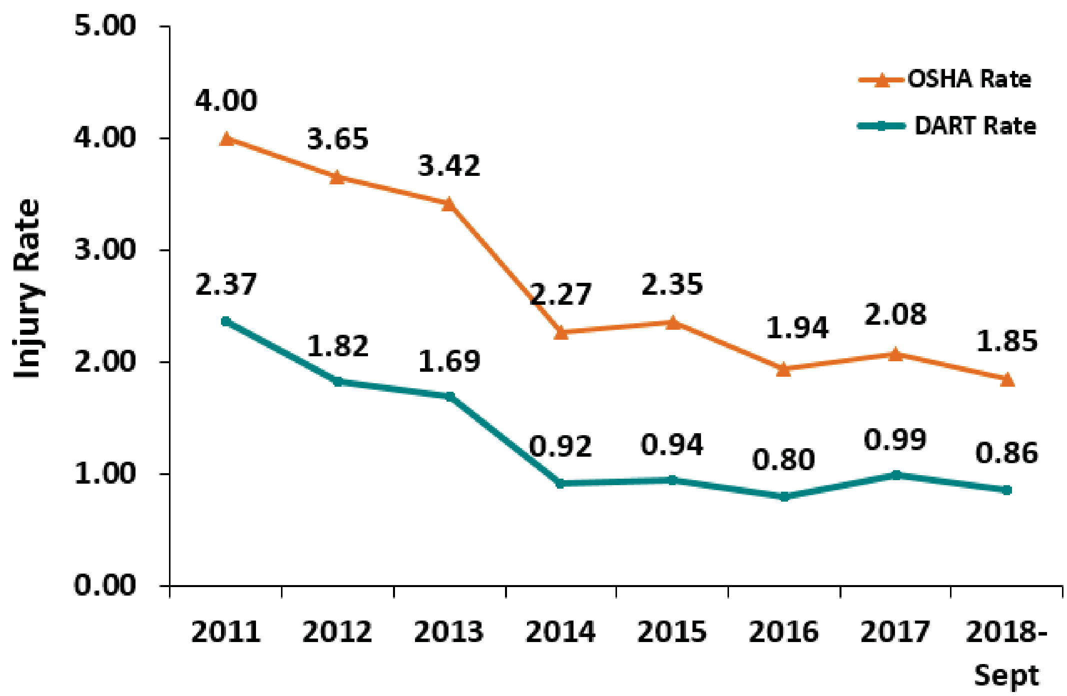
In this chapter, we discuss our safety efforts over the last four years. Within those four years, the first three focused on fostering a strong cultural foundation around programs and tools while preparing leaders to transform the safety culture in year four. The chapter will then look ahead to ongoing and planned efforts to proactively identify and mitigate safety risks to SCE employees, contractors and the public. SCE intends to continue evolving our safety culture to one where safety is perceived as something all employees want to do, instead of something they have to do. This will foster safer mindsets, attitudes, and ultimately behaviors. This is a long-term and continuous process; SCE is committed to making sure that our employees, contractors, and all members of the public in our service territory are safe.

A. We Have Already Significantly Improved in Some of Our Safety Outcomes

1. Employee Safety

SCE has seen dramatic improvements in our safety results. As shown in Figure I-2 below, based on current, year-to-date statistics, since 2011, SCE achieved a 64 percent improvement in employee safety performance, as measured by our DART rate. Our OSHA rate also significantly improved over that same period by 54 percent. Even with improvements, we have some distance to go to achieve and maintain an injury-free workplace.[2] The primary causes for the injuries we are currently seeing are falls and electrical flashes.

Figure I-2 – Employee DART and OSHA Rates, 2011-2018



2. Contractor Safety

In 2015, SCE implemented a contractor safety program, which established four key changes in how we approach contractor safety.

1. The program spearheaded the practice of SCE holding contractors to a standard of safety performance consistent with the standard to which we hold employees or an equivalent standard.

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[2] Our immediate goal is to achieve first quartile performance in safety.

2. We expect contractors to follow SCE safety requirements and periodically assess compliance through field observations and Contractor safety Quality Assurance Reviews (CSQARS) conducted by our SCE field representatives.
3. We have strengthened our oversight and monitoring of contract personnel through multiple safety engagement activities. Examples include: pre-job qualification and safety briefings, on-the-job monitoring, post-job safety evaluations, and SCE-sponsored contractor safety forums.
4. We implemented measures to improve visibility and oversight concerning contractor safety incidents. Contractor safety incidents are now recorded in SCE's safety incident management system, reviewed on the Edison Safety Scorecard, and analyzed so that SCE can complete appropriate root cause analysis and develop actions to prevent future events.

We experienced 18 serious contractor injuries through September, 2018. These were primarily due to falls, and body parts caught in, under, or between equipment. Unfortunately, we also experienced two contractor fatalities through September, 2018 as a result of an induction incident and a fall during tree trimming activities. We will continue to refine our contractor safety program to better and more proactively identify and mitigate factors that lead to serious injuries and fatalities.

3. Public Safety

Protecting the public is central to our mission to provide safe, reliable, and clean electricity. Table I-1 outlines the trend of public serious injuries and fatalities reported to the CPUC from 2014 through September 2018; the primary cause of these incidents was contact with power lines.[3,4]

We have three key approaches to improve our Public Safety outcomes.

1. Programs that evaluate, maintain, and replace infrastructure. These programs help mitigate the risk of system failure contributing to a public safety incident. An example of this is our Overhead Conductor Program, discussed in Chapter 5, Contact with Energized Equipment.

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[3] Incidents are defined as CPUC-reportable incidents involving a fatality or a serious injury as defined by Cal/OSHA. A Cal/OSHA serious injury is defined as any injury or illness (including death), which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an individual suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement.

[4] Please refer to WP Ch. 3, pp. 3.31 – 3.38 (*2014 – 2018 CPUC Reportable Public Fatality & Serous Injury Events)*

2. Outreach programs that provide education and essential information to the public, including billboards, radio campaigns, mailers, and television campaigns in multiple languages. Public Outreach programs are also discussed in Chapter 5, Contact with Energized Equipment.
3. Investigating major incidents to implement improvements and proactively mitigate possible similar incidents.

Table I-1 – Public Safety Incidents, 2014- 2018

Public serious injuries & fatalities *due to system failures*

	2014	2015	2016	2017	2018 YTD Sept
Public Fatalities due to System Failure	0	0	0	1	0
Public Serious Injuries (Cal OSHA) due to System Failure	0	0	0	1	0

Total public serious injuries & fatalities *reported to CPUC*

	2014	2015	2016	2017	2018 YTD Sept
Public Serious Fatalities	11	4	6	4	6
Public Serious Injuries (Cal OSHA)	20	12	8	10	8

B. SCE Developed and implemented a Safety Roadmap in 2015 After Conducting an Enterprise-Wide Assessment of Safety Culture

In 2014, SCE conducted an enterprise-wide Safety Culture Assessment. To address the opportunities for improvement identified in this assessment,[5] SCE developed an Enterprise Safety Roadmap based on assessments, recommendations, and the collective input of senior leaders representing all organizational units across the company. The resulting roadmap focused on 27 initiatives spanning 2015 through 2016. These initiatives were targeted at key areas identified in the assessment as gaps in the SCE culture, and are listed and described in Table I-2 and Table I-3 below.

[5] *Id.*

Table I-2 – Enterprise Safety Roadmap Initiatives, 2015

Category	Initiative	Description
Governance	1 Safety Governance	Launch an Enterprise Safety Governance Structure that ensures alignment and governance over safety across the Enterprise.
Governance	2 Communication Strategy	Develop and implement a communication strategy that creates a common messaging platform for all safety communications, identifies protocols and governance, and identifies corporate and OU responsibilities for safety communications.
Governance	3 Corporate Safety Goal	Develop a corporate safety goal that is multi-tiered and makes safety a required part of Short Term Incentive Program.
Governance	4 Safety PDP Goals	Develop a common safety PDP goal for all leaders to complement the common safety PDP competency.
Governance	5 Safety Scorecard	Develop a safety scorecard with leading and lagging indicators on worker (employee and contractor) and public safety.
Governance	6 Safety Organization & Operating Model	Identify and implement a safety organization and operating model that will be effective and efficient in support of injury-free.
Leadership	7 Executive Safety Engagement	Develop and deliver safety engagement soft skills training to executives to ensure they are able to articulate the company safety vision and lead safety improvement.
Leadership	8 Safety Leadership Development	Develop and deliver safety leadership training that ensures all Edison leaders have strong and consistent safety leadership skills.
Leadership	9 Safety Staff Qualifications & Training	Define minimum qualifications for safety specialists and deliver training that covers their role, technical safety programs, and field investigation techniques.
Leadership	10 Leaders Roles & Responsibilities	Develop specific safety expectations for leaders to be reinforced in training and with PDP goals.
Worker Engagement	11 Observation Program	Develop and implement an integrated companywide observation program that allows for customization by work type and retires existing OU programs.
Worker Engagement	12 Safety Congresses & Teams	Develop and implement an Enterprise plan for safety congresses and teams to improve their effectiveness and impact.
Worker Engagement	13 Safety Recognition Program	Develop and implement an Enterprise safety recognition program that defines safety behaviors and accomplishments core to achieving the safety vision and a program to consistently reward and reinforce those behaviors and accomplishments.
Worker Engagement	14 High Hazard Skills Training	Develop and deliver high hazard skills training for craft employees beyond apprenticeship training.
Worker Engagement	15 Safety Partnership with Union Leadership	Continue to strengthen the safety partnership with union leadership to ensure alignment on safety vision, desired values, activities, and initiatives.
Worker Engagement	16 Contractor Safety Program	Develop and implement Contractor Safety Program that ensures clear safety expectations for contractors that align with expectations for employees.
Safety Systems	17 Incident Management & Investigation	Develop and implement an Incident Management Standard that ensures consistency in how incidents are reported and investigated, and a consistent process to classify and track incidents that are or have potential for serious injury or fatality.
Safety Systems	18 Injury Management & Return to Work	Benchmark injury management and return to work programs, processes, and procedures to identify opportunities for SCE.
Safety Systems	19 Safety Program Evaluation	Develop and implement a plan to ensure the effectiveness and compliance of corporate safety programs and OU implementation of those programs in preventing and mitigating incidents and injuries.
Safety Systems	20 Best Practice Sharing	Develop and launch best practice sharing mechanisms that leverage the Safety Governance Structure to share best practices between OUs and from external benchmarking.

Table I-3 – Enterprise Safety Roadmap Initiatives, 2016

	Initiative	Description
Worker Engagement	1 Safety Roles & Responsibilities	Share safety roles & responsibilities with all employees
	2 Health & Wellness	Incorporate health and wellness into safety
	3 Safety Observation Program	Improve effectiveness and utilization of enterprise-wide observation program and mobile app
Leadership	4 Safety Leadership Development	Define the role of safety for leaders in Edison's leadership philosophy (Vision, People, Accountability)
	5 Executive Safety Skills	Conduct safety skill building for executives
Safety Systems	6 Organizational Learning	Promote continuous learning for injury prevention
	7 Contractor Safety	Further integrate contractors into worker safety

We created an enterprise safety governance structure in 2015 to align the company on our safety direction and execute the Enterprise Safety Roadmap initiatives. It has since evolved to incorporate broader governance responsibilities over employee, contractor and public safety. This governance structure has three levels.

1. The Executive Safety Council (consisting of the CEO and his direct reports, and a senior leader representing EIX). The Executive Safety Council sets and monitors the enterprise safety strategy, reviews key safety incidents, and oversees the execution of safety initiatives;
2. The Senior Safety Council (consisting of executive and senior management across all organizational units). The Senior Safety Council is responsible for operationalizing the safety direction set by the Executive Safety Council and the execution of Safety Culture Transformation initiatives. The Senior Safety Council also identifies, monitors, and refines additional safety initiatives.
3. Operating Unit Safety Councils (consisting of the Operating Unit leadership and employee representatives). The Operating Unit Safety Councils are responsible for: (a) day-to-day execution of the safety direction set out by the Executive and Senior Safety Councils, (b) day-to-day monitoring of the 27 initiatives referenced above, and (c) identification of and follow-up action on safety issues. Within each OU, there are grassroots safety congresses and teams, where employees are empowered to identify and lead efforts to improve safety throughout the workplace.

As part of the Enterprise Safety Roadmap, we focused on clarifying the behavioral expectations for leaders and employees by creating a Safety Roles and Responsibilities guiding document. The content of this document was then integrated into safety competencies and performance development criteria. Additionally, all executive leaders attended half-day workshops and six monthly training sessions to align on their role in improving safety within their groups; these leaders were equipped with tools to further catalyze and sustain the change within their respective organizations.

In 2016, the Executive Safety Engagement effort led to all executive leadership dedicating half a day in the field learning and practicing the skills necessary to better engage with field employees. This directly addressed one of the stronger themes from the 2014 assessment: that leaders needed to be visibly engaged with, learn from, and collaborate with our employees.

When assessing the effectiveness of these activities, the 2017 Safety Culture Assessment found that about 76 percent of participants believed that SCE's safety culture and leadership had improved over the last two years (2015 and 2016). While this improvement in cultural and leadership perceptions was associated with a general downward trend in DART (0.94 to 0.80) over the same time period, we understand that the relationship between safety culture and safety performance is not linear. However, as we continue to focus on aligning employees' safety values, attitudes and behaviors, we expect to see improvements in safety behaviors, and ultimately safety performance, over time.

C. In 2017 SCE Conducted an Assessment and Took Additional Steps on our Journey Toward Improving Our Safety Culture and Reducing Injuries

In the last two quarters of 2016, SCE conducted a desktop review with a safety culture consulting firm to begin planning for the 2017 Safety Culture Assessment. One of the key recommendations from the desktop review was to signal the importance of safety in the organization by modifying the organizational structure. This modification would have Corporate Safety operate as a separate department reporting directly to the CEO through the appointment of a senior safety executive. Shortly after this recommendation, a new executive position of Vice President of Safety, Security and Business Resiliency was appointed, reporting directly to the CEO. This new executive position functions as the Chief Safety Officer for the entire Company, and the executive selected for the position has extensive experience leading safety, training, and compliance programs and organizations in various organizations across SCE over the last 25 years.

Entering 2017, we recognized the progress we had made, but continued to be dissatisfied with the rate of injuries across the company. To evaluate our situation, we asked the safety culture consulting firm that conducted the 2016 desktop review to now conduct a comprehensive Safety Culture Assessment. The survey asked employees questions about their views on the safety climate at the organizational and team level, contractor safety interactions, safety leadership, training quality, safety communications, safety performance, and strengths and weaknesses in learning from errors and speaking up when warranted.

Simultaneously, to supplement the information provided in the surveys, the vendor also conducted an Onsite Safety Evaluation across a geographically and organizationally representative sample. This Onsite evaluation involved experienced consultants conducting interviews, focus groups, and job observations. These activities were conducted with a broadly representative group of employees, from senior leadership positions to field employees. Job observations included field observations, and participation in regular meetings and job site reviews.

One of the core findings of the Safety Culture Assessment was based on the safety culture maturity model (see Figure I-1); SCE was assessed to be at the *Public Compliance* level of safety culture maturity, with some elements emerging of a *Private Compliance* safety culture.

In a Public Compliance safety culture, safety is viewed as something imposed upon the employees by "management" or "the company" (or some outside enforcing agency, such as OSHA), but it is necessary to stay out of trouble with management and/or stay in compliance with regulations. In Public Compliance cultures, safety is usually thought of in terms of "just follow the rules," with primary attention being paid to: (1) complying with safety procedures, (2) avoiding high-risk events, and (3) reducing safety lagging indicators.

In a Private Compliance safety culture, the following characteristics are often observed:

1. Safety is thoughtfully considered by all leadership as a critical means to achieving the company's goals;
2. Safety is seen as a worthwhile personal investment of time and effort by the workforce;
3. Individuals are committed to completing work safely and supporting one another to meet safe production goals; and
4. Individuals value staying safe at work and outside of work, whether in public view or not.

Beyond the safety maturity finding, the Safety Culture Assessment also identified the following themes as specific areas of opportunity:

1. "As My leader goes, so goes the culture"
2. "I speak up…but it depends on who it is and what they are doing"
3. "Regulation not Risk"[6]
4. "I can give my feedback, but I doubt anything will be done with it"
5. "Protect the business, then its people"
6. "Safety is Overkill"

The conclusions and recommendations of this assessment were consolidated into a Safety Culture Transformation program.[7] This program is responsible for developing, implementing, and sustaining discrete initiatives to address specific findings and evolve our safety culture to one of Private Compliance.

The Safety Culture Transformation Program comprises six main focal areas, targeted at inclusively strengthening culture:

1. Common Understanding of Safety Culture Change
2. Leadership and Talent Management
3. Safety Communications
4. Hazard Awareness and Risk Management
5. Safety Data Strategy
6. Safety Governance, Structure and Programs

One of the core tenets of SCE's overarching cultural approach is that leadership drives culture, and a strong safety culture is integral to cultivating and sustaining safe attitudes, values and behaviors. Our second core tenet rests on the fact that recognizing hazards and mitigating risks are skillsets that can be trained and honed over time. While a strong culture will foster the desire and decision-making framework needed to make the right safety choices, there are also cognitive tools that will equip our employees with the specific knowledge and skills to recognize and effectively mitigate hazards.

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[6] This represents an organizational focus on reporting, documentation, rules, policies, and procedures which has cultivated an over-emphasis on meeting the minimum standard. The workforce is predominantly focused on simply upholding the letter, rather than the spirit, of the law.

[7] Please refer to WP Ch. 3, pp. 3.1 – 3.30 *(Safety Culture Transformation Roadmap)*.

Our Leadership and Talent Management approach focuses on three main areas. First, training leaders in cognitive behavioral principles that give them the tools to create an environment where safety is tangibly and psychologically valued. Second, developing and aligning competencies to the overarching safety culture, and then assessing and addressing leadership competency gaps. Third, aligning talent pipeline processes (such as recruitment, selection, and succession planning) with core safety competencies and values.[8]

This strategy of developing effective leaders, shifting employee safety mindsets and providing consistent programs, directly addresses the factors integral to creating and sustaining a strong safety culture.

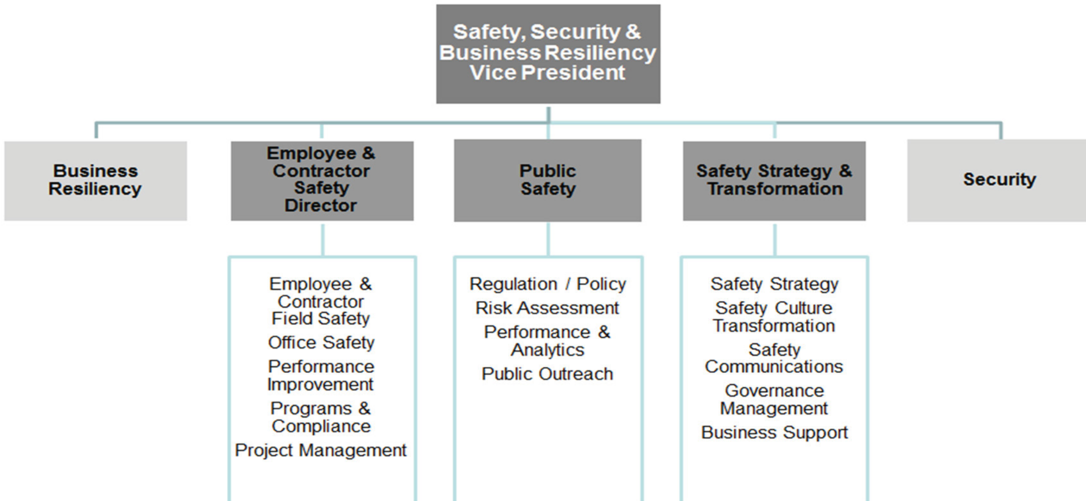
D. Improving our Culture Involved Changing Our Organizational Structure

Our Safety Culture Transformation is moving the Company towards a culture of safety ownership, where each of us, as individuals, chooses to stay safe. As discussed above, in 2017 SCE created an executive position, Vice President of Safety, Security and Business Resiliency, that reports directly to the CEO. Also, SCE strategically evaluated how safety is organized and managed. After reviewing best practices from high-performing organizations (both internal and external), it appeared that a centralized organization could accelerate our safety culture transformation.

On October 1, 2018, we implemented the Edison Safety organization (structure outlined in Figure I-3 below). This organization is led by the Vice President of Safety, Security and Business Resiliency, and consolidates several existing safety organizations across Transmission and Distribution, Generation, Customer and Operational Services and Corporate Health and Safety. The new Edison Safety organization is dedicated to operationalizing the Edison Safety strategy with an increased focus on Public Safety.

[8] Please refer to Chapter 7 – Employee, Contractor & Public Safety for additional information on the Leadership and Talent Management approach.

Figure I-3 – 2018 Edison Safety High Level Organizational Chart



The new organization promotes consistent safety messages, and improves efficiency through the allocation of safety resources across the company. Centralizing the safety organization will also improve our analytical efforts. We are constantly evaluating both leading and lagging indicators to assess our safety performance. We also compare ourselves to peer company benchmarks to evaluate our progress. We have actively pursued a strategy of using predictive analytics.

By focusing on operational, safety and external data to develop predictive models to identify risk factors, we should be able to develop more timely and targeted interventions. In 2018, we are implementing a new Safety Dashboard that will give us better visibility to key statistics and indicators, thereby improving our monitoring capabilities.

Our efforts here align with the longer-term strategies that we can focus on in a centralized organization. This will include:

1. Consolidating safety data systems, using new and improved software tools. With better data and better visibility, we can better manage safety outcomes.
2. Applying consistent classification and documentation processes and criteria across the company. This will improve the volume, consistency and the quality of the data we will have.
3. Using consistent and rigorous methodologies for investigations and documentation.
4. Fostering adequate resourcing.

The Vice President of Safety, Security and Business Resiliency is also responsible for providing comprehensive safety updates to the Board of Directors. This includes all aspects of safety, including conveying results for employee, contractor and public safety; reviewing major safety incidents; evaluating our ongoing safety efforts; and identifying emerging issues.

E. Our Path Forward is Through Improving our Safety Culture

At SCE, considerable progress has been made in safety outcomes and in raising the workforce's safety consciousness. However, we recognize that our past strategy of focusing on awareness campaigns has probably run its course. To transition to a more mature safety culture, we must advance our collective mindset about safety from being something that we have to do, to something that we want to do.

The Employee, Contractor & Public Safety chapter explains the Safety Culture Transformation program in considerable detail, and describes how this program will address some of the Company's key safety risks.

II. Compensation Policies Tied to Safety

A. Introduction to Compensation

Safety is SCE's number-one priority for our workers, for our customers, and for the communities we are privileged to serve. To foster a strong safety culture at SCE, we must use a multifaceted strategy. An important component of this strategy is to reward those who move the safety culture forward in a positive direction. We also tie certain aspects of compensation to how the Company performs in the safety arena.

As a result, SCE incorporates safety into its compensation policies and puts much of this reward at risk, depending on Company and individual performance in this area. This chapter will describe: (i) the structure of compensation for SCE's employees, including the role that safety plays in SCE's fixed and at-risk compensation, and (ii) how safety metrics included in at-risk compensation are established and evaluated.

B. Overview of Compensation

Figure II-1 below provides a general overview of SCE's total compensation structure, broken out by "Fixed" and "At-Risk" categories.

Figure II-1 – SCE Total Compensation Structure

Compensation Category	Compensation Type	Eligibility	
		Non-executive	Executive
Fixed	Base Pay	√	√
	Benefits (Retirement):		
	401(k) Savings Plan	√	√
	Qualified Retirement Plan	√	√
	Non-Qualified Retirement Plan		√
	Benefits (Health & Welfare)	√	√
	Benefits (Disability)	√	√
At-Risk	Variable Pay:		
	Short-term Incentive Plan (STIP)	√	
	Executive Incentive Compensation Plan (EIC)		√
	Long-term Incentive Plan (LTI)		√

Generally, SCE's total compensation (including retirement and benefits) consists of two distinct categories — "fixed" and "at-risk" compensation. The compensation categories and their connection to safety performance are explained further in the following sections.

C. Fixed Compensation

Base pay, expressed as an hourly rate of pay for non-exempt employees or as ongoing salary for exempt employees, represents the fixed component of pay. Base pay recognizes the ongoing performance, skills, competencies, and knowledge of job responsibilities of SCE's employees. Base pay levels are evaluated through annual assessments and yearly individual performance reviews. Unlike variable pay, base pay amounts are generally not subject to adjustment during the applicable year based on employee or Company performance against annual Company goals. As such, this compensation type is not considered at risk.

Another aspect of fixed pay is the package of core benefits offered by SCE to its employees, which may be based on their hire date. This package includes health and welfare benefits (i.e., medical, dental, and vision plans, and life insurance), the 401(k) savings plan, retirement plan, and disability benefits. Base pay currently represents approximately 92 percent of non-executives' cash compensation, which includes variable pay. For executive employees, base pay currently constitutes approximately 53 percent of their cash compensation.[9]

1. How Safety Factors Into Fixed Compensation

The base pay of non-represented employees, including all executives and the Chief Executive Officer (CEO), is set each year by annually evaluating each individual's performance and examining where that employee's base pay falls compared to market data. We update market data annually for executive positions and biennially for non-executive positions.[10]

Performance evaluations include individual performance goals, plus goals targeted toward adherence to and promotion of Company values[11] and competencies. **Performance goals** may include safety-related objectives specific to an employee's job function. **Values** are the principles that guide what we do and the foundation for how we do it. One of SCE's values is Safety, and the following are guiding behaviors expected of each employee:

- Acts as a safety culture leader

[9] This represents an average for SCE executives. The percentage is based on preliminary, unaudited numbers.

[10] In years where non-executive, individual jobs are not market-reviewed, the entire non-executive salary structure is adjusted for overall market conditions.

[11] SCE's company values include safety, teamwork, excellence, respect, integrity, and continuous improvement.

- Always works safely and stops unsafe work
- Coaches and recognizes safe work practices and behaviors
- Looks out for others
- Masters safety – understands the work and knows the safety risks
- Always visibly models and promotes safe behaviors

Each position has a defined set of **competencies**. These competencies are determined based on whether the position is in an individual contributor or leader role. All non-represented SCE employees have a safety competency – "Creates a Safety Culture" – designed to strengthen and sustain SCE's safety culture. The following are some of the ways that employees are expected to demonstrate their commitment to safety for themselves and their team:

- Demonstrates a genuine interest in the well-being and safety of others.
- Considers safety as the highest priority when making decisions.
- Proactively engages in safety programs and activities.
- Coaches others on safety, reinforcing desired behaviors and providing guidance to address unsafe behaviors.
- Demonstrates safety is a personal priority by aligning actions with the vision for an injury-free workplace.[12]
- Continuously deepens knowledge in work process risks and educates others in behaviors and methods that reduce risk.

At the end of each year, managers rate the performance of each participating employee in two ways: 1) how well they did in achieving their individual performance goals as well as the day-to-day responsibilities of their jobs; and 2) how well they demonstrated the Company's values and competencies, including the Safety value and "Creates a Safety Culture" competency. Managers then consider this performance rating when they are recommending an employee's annual increase to their base pay. While SCE's represented employees do not participate in the annual evaluation and merit increase process, leaders who establish work priorities for those employees are fully accountable for creating an environment where all employees understand that Safety is SCE's top priority.

[12] Applicable to employees who are individual contributors. SCE leaders are expected to demonstrate safety is a personal priority by developing and communicating a clear vision for an injury-free workplace.

D. At-Risk Compensation

SCE has two bonus plans: the Short-term Incentive Plan (STIP) for non-executive employees and the Executive Incentive Compensation Plan (EIC) for executive employees. SCE executive compensation also includes Long-Term Incentives. These at-risk compensation components are explained below.

1. Safety Affects Bonus Plans

Each position at SCE has an established bonus target opportunity. This opportunity may vary depending on: (1) how the Company performs against its annual goals; and (2) how the employee performs against his/her individual goals, values, and competencies.[13] A similar process is used for non-officer executive[14] target opportunities. The Company determines target opportunities for executive officers based on market data. Non-executives' bonus target opportunity ranges from 4 to 25 percent, and the executive bonus target opportunity ranges from 30 to 75 percent.

Company goals include metrics related to safety, reliability, customer satisfaction, and affordability. These metrics are established each calendar year by the Compensation Committee of the Board of Directors ("Compensation Committee"), which is comprised of independent directors.

SCE's 2018 goals incorporate Safety in three primary ways:

- First, SCE's 2018 goals include certain foundational goals. If any of these foundational goals are not met, the result can be a reduction to the overall Company goal performance score. The foundational goals can also be used in evaluating an individual employee's performance for compensation purposes. SCE's foundational goals incorporate metrics tied to worker and public safety, including the avoidance of (a) worker fatalities; (b) serious injuries to the public resulting from system failures.[15]
- Second, SCE's Safety goal evaluates the Days Away, Restricted, or Transferred (DART) rate, actions taken toward our Safety roadmap, and communications regarding safety incident cause evaluations. This goal carries a 10% payout weighting for the bonus plans.

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[13] Factor number two does not apply to non-exempt employees.

[14] "Non-officer executive" refers to an executive at the Director level.

[15] Please see below for a specific example where performance on the foundational safety goals led to the incentive compensation of certain senior executives being reduced.

- Third, SCE has a People goal that includes a metric to complete safety training for employees in high-hazard roles in the Transmission & Distribution operating unit.

SCE developed the 10% safety goal weighting for bonuses and the foundational goals to help incentivize safety engagement and ownership across all levels of the organization through a vested financial stake in safety performance. Safety is also imbedded in other goals, such as goals concerning reliability (which can affect public safety).

SCE sought to strike a balance here. On the one hand, it has been recognized by experts that overweighting compensation goals toward safety can actually be detrimental to safety. OSHA, for example, frowns on basing compensation on how many or how few injuries an enterprise has,[16] because it can lead to unintended consequences such as under-reporting of safety incidents and potentially have a chilling effect on employees speaking up about safety incidents. On the other hand, SCE needs to have its compensation goals reflect its priorities, and safety is the chief priority. The safety goals and weighting SCE has chosen represent that balance. Every employee sees and can be impacted by the emphasis SCE places on safety, but the compensation goals are not over-weighted so as to potentially encourage unwanted behavior.

Figure II-2 below shows SCE's 2018 performance goals and the target weightings for each. These apply equally to executives and non-executives.

[16] *See* OSHA Memorandum from Deputy Secretary Richard E. Fairfax re: Employer Safety Incentive and Disincentive Policies and Practices, (March 12, 2012), *available at* https://www.osha.gov/as/opa/whistleblowermemo.html. Please also refer to OSHA's discussion of incentives at section II.C, *available at* https://www.osha.gov/recordkeeping/finalrule/interp_recordkeeping_101816.html

Figure II-2 – SCE 2018 Performance Goals

SCE	Score		
Goal Category	Threshold (Unmet)	Target (Met)	Stretch (Exceeded)
Foundational Goals	If any of these occur, Compensation Committee may deduct points from the score		
Financial Performance	0-39	40	41-80
Operational and Service Excellence Safety Others (Customer Satisfaction, Reliability, Affordability and SONGS Decommissioning)	 0-9 0-14	 10 15	 11-20 16-30
Policy, Growth and Innovation	0-24	25	26-50
Diversity, People, and Culture	0-9	10	11-20
Total multiplier range	**0-99**	**100**	**101-200**

SCE determines Company goal performance by using three different measures for each category – Threshold, Target and Stretch – signifying the extent to which the goals were met in that area. Threshold refers to the minimum expected performance, while Stretch means goal performance has exceeded expectations for that area.

2. How SCE Establishes and Evaluates Safety Metrics for Compensation Purposes

Safety metrics that can affect compensation are developed by SCE's Corporate Health and Safety group, now known as "Edison Safety."[17] On an ongoing basis, the Utility Management Team (UMT) and the Edison International Managing Committee (EMC) review and may recommend changes to these metrics before they are approved by the Compensation Committee.

For the Safety target specifically, the key measurement involves the rate of "Days Away, Restricted or Transferred," also known as the "DART rate." To help determine this rate each year, the Company uses a combination of historical DART rate performance and expected performance based on top quartile industry benchmarks. Expected performance also takes into account the maturity of SCE safety culture initiatives and the realistic timeframe to achieve first

[17] Please *see* Chapter 7 (Employee, Contractor & Public Safety) for more information on this organization.

quartile performance, as determined by SCE's Corporate Health and Safety Group and approved by the UMT, EMC, and the Board of Directors.

In addition to the DART target, the 2018 Safety goal also includes: implementing actions in the Hazard Awareness and Risk Mitigation Safety Roadmap workstream, and performing and communicating effective cause evaluations on all fatalities, serious injuries, and potentially life-altering incidents.

SCE's foundational goals also include metrics tied to worker and public safety, including the avoidance of (a) worker fatalities; (b) serious injuries to the public resulting from system failures; (c) significant non-compliance events and significant disruptions; and (d) data breaches or system failures that adversely impact critical infrastructure or result in a breach of customer or employee data.

3. How Safety Affects Payout of Bonuses

At the end of each year, SCE evaluates its performance against the goals; the results are used as the basis for the bonus payout. Each goal category is assigned a score, the sum of which determines the multiplier (0 percent - 200 percent). The Compensation Committee approves and has discretion over the final scores. In the event one or more of the foundational goals are not met, Company management and the Compensation Committee may reduce or even eliminate the bonus payouts depending upon severity.

Last year, SCE's senior management demonstrated its commitment to have senior executives' compensation reflect safety performance. In 2017, SCE had two public safety incidents that senior management felt did not measure up to the foundational public safety goal. Each of the incidents involved a single individual. As a result of these two incidents, SCE's Chief Executive Officer and other senior leaders recommended to the Compensation Committee that a number of executives (including the Chief Executive Officer) receive a deduction to the individual performance factor of their bonus. It was a 10-point deduction for not meeting SCE's foundational public safety goal, meaning 10 percent of the 100-point target. This deduction was in addition to an 8-point deduction for missing SCE's goal to reduce employee injury rates.

The Compensation Committee agreed with the recommendation. The decision to reduce executive compensation was not made because of a Commission mandate or other regulatory requirement. Instead, it was made because SCE believes that it is appropriate to hold its senior leadership financially accountable for safety.

The recommended bonus payout for each employee and executive equals his or her target bonus, adjusted for the corporate modifier. Executives and exempt, non-represented, employee payouts are further modified by an individual performance modifier based on their overall performance for the calendar year. Awards for senior executive officers are also reviewed and approved by the Compensation Committee.

4. Long-term Incentives

SCE executive compensation also includes Long-Term Incentives (LTI). This is another compensation element that is considered at-risk, since the value of LTI depends on several factors, including multiple years of continuous employment, strong job performance at the executive level, and financial health of the Company. LTI includes non-qualified stock options, restricted stock units, and performance shares, with multi-year vesting periods from three to four years.

Each year, SCE performs a detailed market assessment of its executive workforce to assess each compensation package, including LTI. An executive's LTI is determined based upon the market data applicable for his or her position. The actual grant may vary based on an annual assessment of that individual's performance. The actual value of the award is determined after the vesting period based on Company performance.

While there is not an express safety metric embedded in LTI, the primary driver of LTI performance – long-term Company value – can be significantly impacted by SCE's safety performance. A safety issue could cause Company stock to underperform, resulting in reduced value of performance shares, restricted stock units, and stock options.

E. Safety Recognition Program

SCE's Safety Recognition Program supports positive safety behaviors by giving employees an opportunity to recognize and be recognized for demonstrating their commitment to advancing the Company's safety culture. All employees are eligible to, and encouraged to, actively participate in the program.[18]

Examples of the safety-related behaviors that are recognized include:

- Identifying previously unrecognized hazards;
- Participating in safety events and committees;

[18] Executives cannot actually receive awards under this program. The focus in the area of awards is to give such tangible rewards to non-executive employees.

* Stopping work after spotting unsafe conditions; and
* Preventing a serious incident from occurring among co-workers and/or the public.

F. Conclusion

As we said at the outset of this chapter, safety is SCE's number-one priority for our customers, for our workers, and for our communities. We are firmly committed to continuing to strengthen our safety culture. Our compensation policies are just one aspect of how we are doing this. Employees at all levels within the organization play a vital role in safety. During our performance evaluation process, each employee has safety-related competencies as part of their evaluation. Moreover, safety performance is expressly recognized in SCE's short- and long-term at-risk compensation, via our safety goal and foundational goal performance. The Company continues to evaluate and refine its safety metrics as our safety culture matures.

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL® Company

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Building Safety

Chapter 4

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

This chapter analyzes potential safety risks that buildings can pose to their occupants. SCE analyzed a variety of potential risk sources that could compromise the safety of a building for its occupants. This analysis resulted in three drivers: earthquakes, failure of electrical systems, and extreme wind.

Earthquakes can lead to both structural failures (e.g., wall, ceiling, and floor collapse) and non-structural failures (e.g., furniture falls over). Failure of a building's electrical systems can harm occupants or cause a fire within the building. Finally, extreme wind can propel objects through the air, with the risk that objects penetrate a building and injure occupants.

This chapter describes two compliance activities:[1]

- Fire Life Safety Compliance (CM1): This include systems and components focused on fire detection, suppression, and/or notification of building occupants.
- Electrical Compliance (CM2): These activities focus on safely installing, using, and maintaining building electrical systems.

In addition to the compliance activities, the chapter describes two controls:[2]

- Seismic Building Safety Program (C1): This include activities to identify, prioritize, and implement seismic improvements to occupied buildings.[3]
- Facility Emergency Management Program (C2): This includes activities to train employees on safety protocols during and after events such as an earthquake.

Finally, this chapter describes five potential mitigations:[4]

- Fire Life Safety Portfolio Assessment (M1): Assessing existing Fire Life Safety (FLS) systems and prioritizing potential improvements to these systems.
- Electrical Inspections (M2): Identifying and mitigating potential electrical failures on a preventative basis.

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[1] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[2] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

[3] SCE has excluded specific references to confidential material in this chapter related to seismic safety. If requested, SCE will take all reasonable measures to provide additional information to the Commission, its Staff, and interested parties, to help evaluate this report.

[4] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

- Wind-Borne Debris Protection (M3): Installing protective film on windows that increases the window's ability to resist shattering and penetration.
- Permanent Work(er) Relocation (M4): Relocating employees from an existing location to alternate locations, without replacement of the original location.
- Building Replacement (M5): Replacing an existing building with a new building.

SCE has developed three risk mitigation plans for consideration:

- The Proposed Plan continues existing seismic and emergency management programs while adding the new mitigations related to FLS systems and electrical inspections (M1 and M2, respectively).
- Alternative Plan #1 adds the new mitigations of permanent worker relocation and building replacement (M4 and M5, respectively) to the Proposed Plan.
- Alternative Plan #2 adds the new mitigation for wind-borne debris (M5) to the Proposed Plan (but does not add M4 and M5).

B. Scope

This chapter focuses on occupied buildings owned or leased by SCE. Table I-1 – Chapter Scope indicates the scope of the chapter.

Table I-1 – Chapter Scope

In Scope	• SCE buildings that are occupied (i.e., at least one employee has assigned seating). A total of 170 buildings meet this criteria (e.g., office buildings, service centers, garages, manned substations, etc.).[5] • Safety risks when the building or its components fail.
Out of Scope	• Buildings that are not occupied, such as unmanned substations, (these buildings do not pose a direct safety risk due to being unoccupied). • Occupied buildings at the San Onofre Nuclear Generating Station (SONGS).[6] • Safety risks not directly caused by the building (e.g., workplace violence or people performing unsafe acts) which are covered in other RAMP chapters.

C. Summary Results

Table I-2 below summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 - 2023 period. Figure I-1Table I-1 illustrates the composition of consequences within the baseline risk. Sections II – VII of this chapter provide further detail and context for these results.

[5] Appendix A, *Summary of Buildings In Scope*, summarizes the number of buildings within each building category.

[6] As described in Chapter I, SONGS is generally out of scope for the RAMP report. However, SCE has provided a supplemental analysis to describe safety risks at SONGS, per the request of the Commission's Safety & Enforcement Division (SED). This is found in Appendix A – Nuclear Decommissioning of this RAMP report. SCE also notes that due to its status as a nuclear facility, SONGS is subject to safety compliance standards (e.g., per the Nuclear Regulatory Commission) that in some cases exceed the compliance requirements faced by the non-nuclear buildings analyzed in this chapter.

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Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Seismic Building Safety Program	X	X	X
C2	Facility Emergency Management Program	X	X	X
M1	Fire Life Safety Portfolio Assessment	X	X	X
M2	Electrical Inspections	X	X	X
M3	Wind-Borne Debris Protection			X
M4	Work(er) Relocation		X	
M5	Building Replacement		X	
Mean (MARS)	*Cost Forecast ($ Million)*	$11.5	$46.8	$11.6
	Baseline Risk	2.42	2.42	2.42
	Risk Reduction (MRR)	0.30	0.35	0.34
	Remaining Risk	2.12	2.07	2.08
	Risk Spend Efficiency (RSE)	0.026	0.007	0.029
Tail Average (MARS)	*Cost Forecast ($ Million)*	$11.5	$46.8	$11.6
	Baseline Risk	7.77	7.77	7.77
	Risk Reduction (MRR)	0.96	1.12	1.09
	Remaining Risk	6.82	6.65	6.68
	Risk Spend Efficiency (RSE)	0.083	0.024	0.094

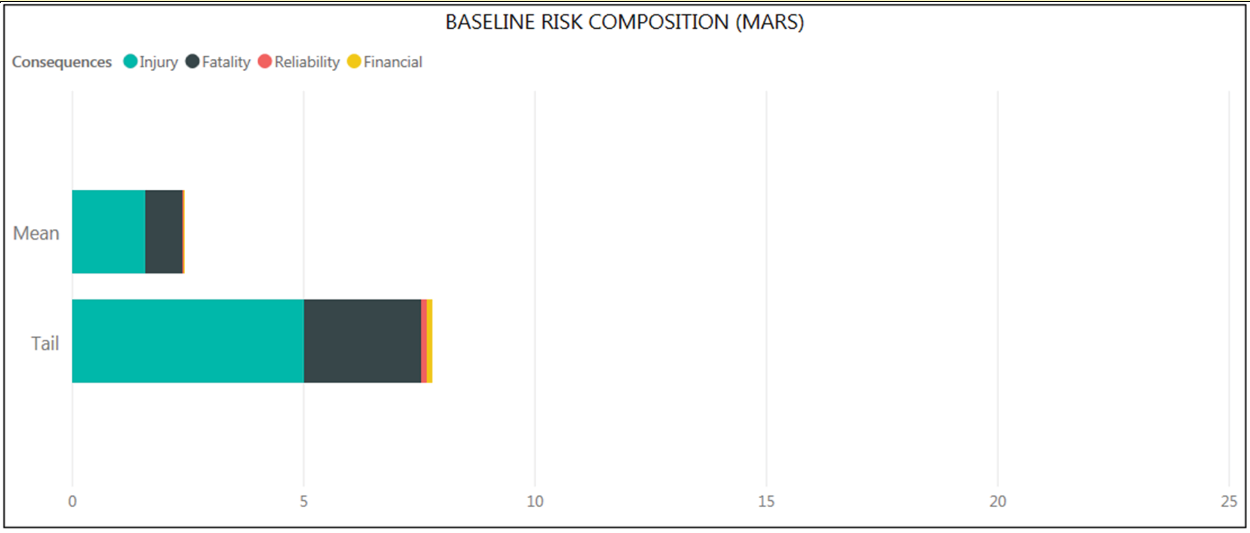
Figures represent 2018 - 2023 annual averages.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

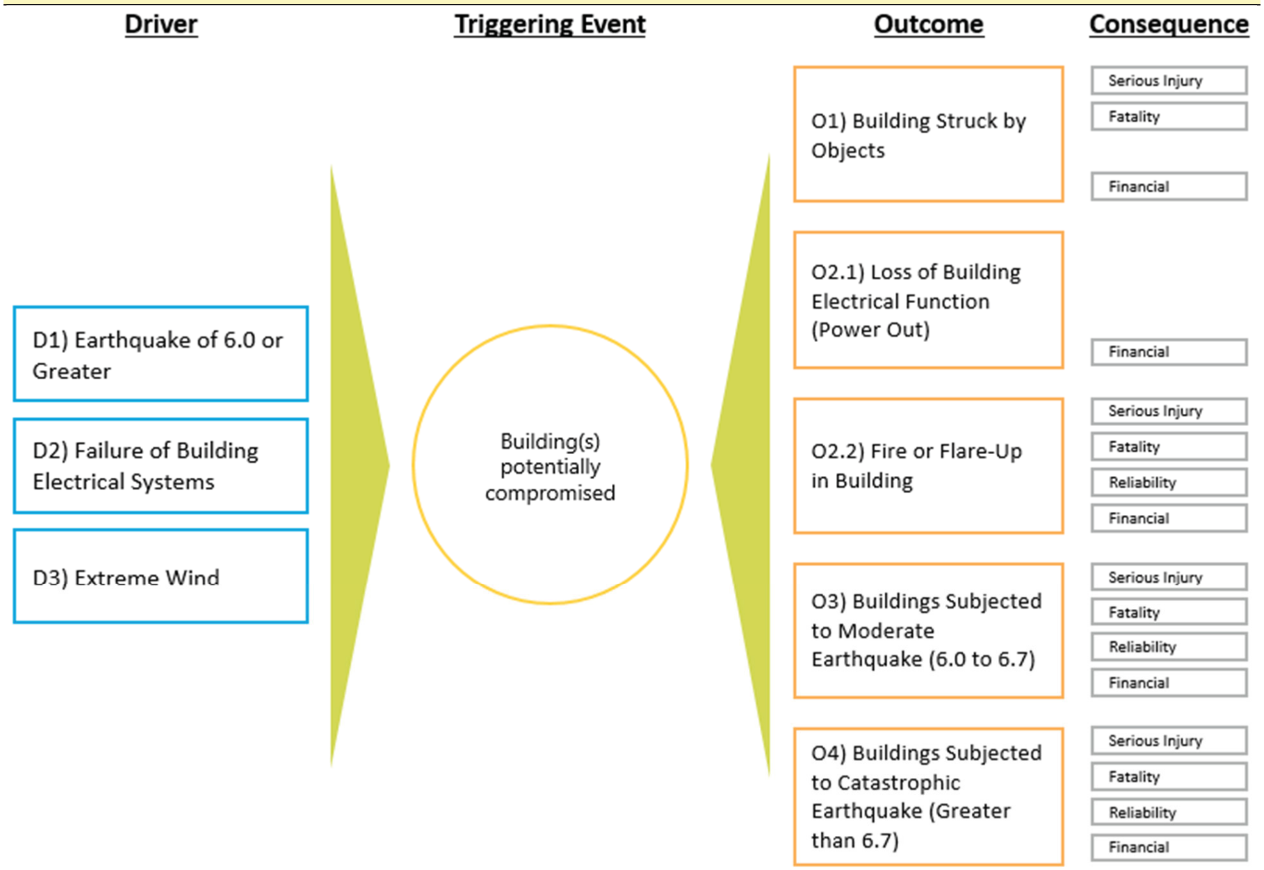
SCE employs a systematic and comprehensive approach to building safety. This includes policies, programs, procedures, and tools to help ensure that operations are performed in accordance with applicable laws, regulations, and best business practices. Our goal is to provide a safe and healthy work environment for our workers and visitors that come to our facilities. We describe these efforts in greater detail in Section III (Compliance & Controls) and Section IV (Mitigations).

Because seismic risk is a major element of building safety, SCE launched a Seismic Assessment and Mitigation Program in 2016 to promote company-wide seismic resilience (Appendix C – Seismic Events of SCE's RAMP report contains additional details on SCE's Seismic Assessment and Mitigation Program). This program coordinates seismic improvement projects for electric, generation, and telecommunications infrastructure, in addition to administrative and operational facilities. The 170 buildings within the scope of this chapter have been assessed under this program. The results of these assessments have informed both the priority for selecting buildings for seismic mitigations as well as the risk modeling presented in this chapter.

B. Risk Bowtie

To define and evaluate this risk, SCE has constructed a risk bowtie, as shown in Figure II-1. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

Figure II-1 – Building Safety Risk Bowtie



C. Drivers

SCE evaluated a large number of potential risk drivers related to building safety. After excluding several potential drivers (see Appendix A of this chapter for more detail), SCE developed this chapter around three drivers, shown in Figure II-2. Each driver is discussed in greater detail below.

Figure II-2 – 2018 Projected Driver Frequency*

Name	Freq	Frequency
D1 - Earthquake of 6.0 or Greater	0	
D2 - Failure of Building Electrical Systems	13	
D3 - Extreme Wind	12	

**D1 frequency is 0.3; the chart shows a value of 0 due to rounding.*

1. D1 – Earthquake of 6.0 or Greater

Table II-1 shows how the United States Geological Survey (USGS) has characterized earthquake outcomes for different levels of magnitude:

Table II-1 – USGS Earthquake Intensity Levels

Magnitude	Typical Maximum Modified Mercalli Intensity
1.0 - 3.0	I
3.0 - 3.9	II - III
4.0 - 4.9	IV - V
5.0 - 5.9	VI - VII
6.0 - 6.9	VII - IX
7.0 and higher	VIII or higher

Each intensity level (I, II, III, etc.) is characterized in terms of its “effects on people, human structures, and the natural environment.” Intensity levels VII and above are characterized according to the USGS per the descriptions in Table II-2.

Table II-2 – Earthquake Intensity Level Outcome Characterizations

Level	Characterization
VII	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.
VIII	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.
IX	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.
X	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.
XI	Few, if any (masonry) structures remain standing. Bridges destroyed. Rails bent greatly.
XII	Damage total. Lines of sight and level are distorted. Objects thrown into the air.

Based on the USGS characterizations described above, SCE selected 6.0 (corresponding to intensity level VII and above) as a lower bound for the range of earthquakes that would potentially have safety impacts.

SCE analyzed driver frequency by comparing the location of the buildings in scope for this chapter against known earthquake faults and the potential for those faults to be active and to reach a magnitude of 6.0 or greater (as defined by the Uniform California Earthquake Rupture Forecast Version 3 Time-Dependent Model, or UCERF3-TD).[7] These simulations predicted that one or more occupied SCE buildings will experience strong shaking as the result of an earthquake of magnitude 6.0 or greater at a rate of 0.344 events per year (cumulatively for the entire portfolio of 170 buildings).

[7] Field, E. H., R. J. Arrowsmith, G. P. Biasi, P. Bird, T. E. Dawson, K. R. Felzer, D. D. Jackson, K. M. Johnson, T. H. Jordan, C. Madden, A. J. Michael, K. R. Milner, M. T. Page, T. Parsons, P. M. Powers, B. E. Shaw, W. R. Thatcher, R. J. Weldon, and Y. Zeng (2015). Long-Term, Time-Dependent Probabilities for the Third Uniform California Earthquake Rupture Forecast (UCERF3), Bull. Seism. Soc. Am. 105, 511–543.

2. D2 – Failure of Building Electrical Systems

Failure of critical electrical components can potentially cause loss of building operational systems, loss of power to the building, flare-ups, and fires.

The basic components of an electrical system are the main switchgear, circuit breakers, panel boards, and transformers. The voltage in these systems ranges from 120 volts to 480 volts.[8] Although rare, an electrical component or system can fail due to factors including age, operating conditions, circuit load, and maintenance. The focus of this driver is on major failures that have the potential to cause a loss of power within the building, a flare-up, or a fire.

SCE regularly inspects and replaces equipment before failure occurs, and has not historically tracked and maintained records regarding the specific cause of equipment failures. For example, SCE maintains records of the work orders and associated repair work. However, these records do not typically include the cause of the equipment failure. As such, SCE does not have a dataset of historical failures to inform a forecast of future failure rates. To estimate the potential frequency of failure, SCE used a building estimation model[9] to estimate the total number of electrical components per building category. SCE estimated a failure rate of 0.5%[10] after considering the compliance activities described in Section III. SCE then calculated event frequency as a function of the probability of failure multiplied by the number of electrical components. For example, if a building has four circuit breakers, the frequency of failure is 0.5% * 4 = 0.2 per year. Performing this analysis for the entire population of buildings in scope resulted in a driver frequency of 13.4.

3. D3 – Extreme Wind

Chapter 12 (Climate Change) discusses SCE's ongoing efforts to examine the near-, medium- and long-term vulnerabilities and impacts of climate change and extreme weather events.

As a complement to that analysis, SCE included extreme wind as a driver in this chapter. SCE narrowed the focus of extreme wind as a risk driver to focus on the safety risk that arises for building occupants when wind speeds occur that can potentially propel external objects through building walls or windows.

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[8] For example, building components such as HVAC equipment operate at 480 or 208 volts, lighting at 277 or 120 volts, and convenience outlets at 120 volts.

[9] This estimation model is used to model buildings and other assets, and it also contains component data derived from manufacturers, service providers, and site management.

[10] Failure rate estimation supported by SME with over 30 years of work experience in Facility Management. Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment) and to WP Ch. 4, pp. 4.13 (SME Qualifications).*

Hurricanes are measured on the Saffir-Simpson Hurricane Wind Scales,[11] which run from Category 1 up to Category 5. For purposes of this analysis, SCE defined extreme wind as anything equivalent to or greater than a Category 1 hurricane (where winds range from 74 to 95 mph). Winds at these speeds have the potential to move objects through the air. These objects can strike and potentially penetrate a building. Note that winds at this speed are not sufficient to tear off a roof that was constructed to the standards utilized by SCE; the resulting damage would likely be limited to operational inconvenience.

SCE performed a historical analysis of the frequency of extreme wind events at the 170 buildings in question. This analysis determined that, on average, there were 12.2 instances per year in which an individual building was subjected to extreme winds. This analysis was based on periods ranging from 19 to 31 years in duration (the timeframe of available data varies due to different times when measuring equipment was installed).

D. Triggering Event

The triggering event is defined as building(s) being potentially compromised, meaning the building is unable to fully ensure the safety of occupants. Figure II-3 shows the composition of the triggering event by individual drivers. As each driver is not expected to materially change in the short term, the frequency does not change over the RAMP time period.

Figure II-3 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	**Total**
Building Safety							
Baseline	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**155.72**
Driver							
D1 - Earthquake of 6.0 or Greater	0.34	0.34	0.34	0.34	0.34	0.34	**2.06**
D2 - Failure of Building Electrical Systems	13.40	13.40	13.40	13.40	13.40	13.40	**80.40**
D3 - Extreme Wind	12.21	12.21	12.21	12.21	12.21	12.21	**73.26**
Total	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**155.72**

[11] Category 1: 74-95mph; Category 2: 96-110mph; Category 3: 111-129mph; Category 4: 130-156mph; Category 5: 157mph or greater.

E. Outcomes & Consequences

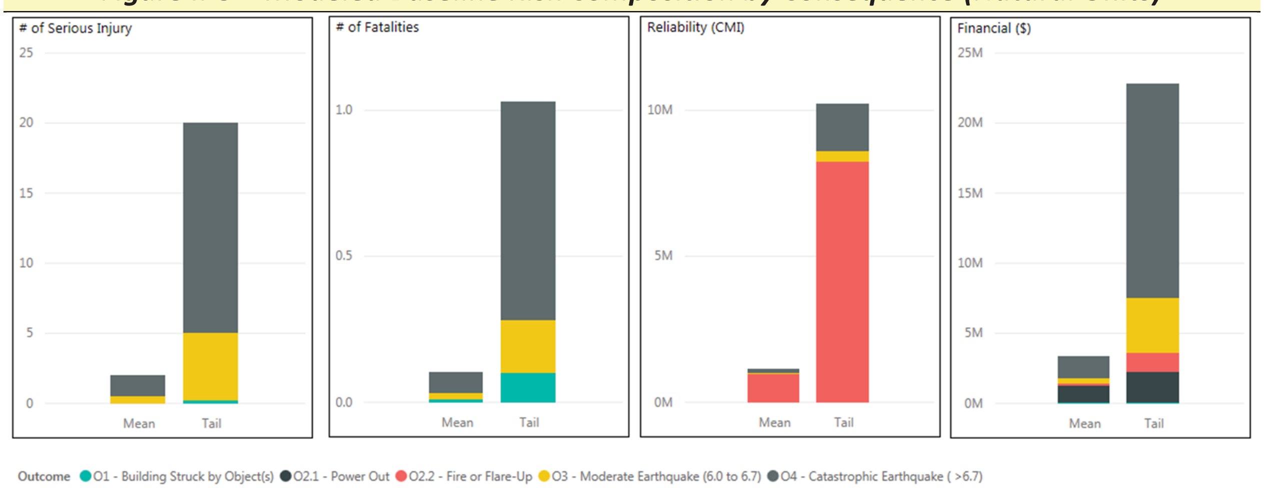
SCE has identified five outcomes, which are described in greater detail below. Figure II-4 indicates the relative likelihood of each outcome should the triggering event occur.

Figure II-4 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Building Struck by Object(s)	47.0 %	
O2.1 - Power Out	50.9 %	
O2.2 - Fire or Flare-Up	0.8 %	
O3 - Moderate Earthquake (6.0 to 6.7)	0.8 %	
O4 - Catastrophic Earthquake (>6.7)	0.5 %	

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence dimension. The sections that follow describes the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)



1. O1 – Building Struck by Objects

Outcome 1 is related to potential damage caused by wind-borne objects that strike and potentially penetrate the building envelope, causing a safety risk to building occupants within the building. Examples include wind-propelled material from trees, poles, and towers. In addition, debris coming from neighboring buildings or equipment that are not securely fastened to the building or anchored to the ground could become airborne and penetrate a window.

Potential consequences from O1 are summarized on an annualized basis in Table II-3. Serious injuries and fatalities are associated with occupants located near the window where the building is struck. Financial costs are associated with repairing the damage. For O1, the estimate of annual impacts is .002 serious injuries, .001 fatalities, and $37K of financial harm on a mean basis, and .0016 serious injuries, .008 fatalities, and $66K of financial harm on a tail-average basis.

Table II-3 – Outcome 1 (Building Struck by Objects): Consequence Details[12]

Outcome 1		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform statistical distribution*	Facilities experts estimated range of 0-3 serious injuries per occurrence based on evaluation of employee proximity to potential window impact locations given typical arrangement of SCE workstations.	50% of injury range, based on historical ratio of fatalities per injury for wind events in California from 2013 through 2017. Data source is National Oceanic and Atmospheric Administration storm events database.	N/A	SCE facility managers estimated property damages would range from $0-150K, with an average expected cost of $20K based on repairs costs under typical scenarios.
Model Outputs	NU - Mean	0.02	0.01	N/A	$37K
	NU - Tail Avg	0.20	0.10	N/A	$66K

2. O2.1 – Loss of Building Electrical Function (Power Out)

Outcome 2.1 evaluates consequences when one or more building systems dependent on electricity (e.g., lights, air conditioning, elevators, etc.) lose functionality, requiring employees to vacate the building and rendering it inoperable until functionality is restored. Restoration times would typically be less than 24 hours.

Potential consequences from O2.1 are summarized on an annualized basis in Table II-4. Financial costs are associated with repairing the damage. For O2.1, the estimate of annual impacts is $1.2M of financial harm on a mean basis, and $2.1M of financial harm on a tail-average basis.

[12] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

Table II-4 – Outcome 2.1 (Building Power Out): Consequence Details[13]

Outcome 2.1		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform statistical distribution*	N/A	N/A	N/A	Based on SCE historical facility capital repair costs over 2016-17 (limited to building types in scope).
Model Outputs	NU - Mean	N/A	N/A	N/A	$1.2M
	NU - Tail Avg	N/A	N/A	N/A	$2.2M

3. O2.2 – Fire or Flare-up in Building

Outcome 2.2 evaluates potential consequences when the failure of building electrical systems results in an arc flash. An arc flash is the sudden release of electrical energy that jumps through the air, and is caused when a high-voltage gap exists between conductors in building electrical systems or equipment. During an arc flash, energy is released that can reach up to 35,000 degrees Fahrenheit. An arc flash and the associated flare-up has the potential to cause a fire.

Potential consequences from O2.2 are summarized on an annualized basis in Table II-5. Serious injuries and fatalities are associated with occupants located in the building when the fire occurs. Reliability impacts are associated with the potential for the fire to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O2.2, the estimate of annual impacts is .0027 serious injuries, .0002 fatalities, 952K customer minutes of interruption (CMI), and $141K of financial harm on a mean basis; and .0270 serious injuries, .0022 fatalities, 8.2M CMI, and $1.4M of financial harm on a tail-average basis.

[13] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

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Table II-5 – Outcome 2.2 (Fire or Flare-Up): Consequence Details[14]

Outcome 2.2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Average injury rate of .014 based on two industry data sources (FEMA & National Fire Protection Agency).	Average fatality rate of .0014 based on two industry data sources (FEMA & NFPA).	Based on the same analysis as Outcome 4, but scaled down to represent impact to a single building (as opposed to multiple buildings in the earthquake scenario in Outcome 4).	Estimates of repair costs range from building equipment replacement costs to full-scale building destruction due to fire, based on historical repair costs and facility manager experience.
Model Outputs	NU - Mean	0.003	0.0002	952K CMI	$141K
	NU - Tail Avg	0.027	0.0022	8.2M CMI	$1.4M

4. O3 – Buildings Subjected to Moderate Earthquake (6.0 to 6.7)

Outcomes 3 and 4 capture the range of possible impacts under moderate and catastrophic earthquake conditions.

As discussed in Section II, SCE used the minimum of 6.0 as a lower bound for an earthquake magnitude that has the potential for safety impacts. SCE then separated the range of potential earthquakes outcomes above 6.0 into two categories (6.0 to 6.7 and greater than 6.7) to more clearly identify the difference in a moderate earthquake versus a catastrophic earthquake. SCE used USGS analyses[15] to define the cutoff of 6.7 to serve as the threshold for a catastrophic earthquake.

Shaking intensity is related to magnitude, distance from epicenter, and other geological variables such soil composition. The extent of damage, serious injuries, and fatalities will vary based on factors such as the age and design of a building, the height of a building, and its distance from the epicenter of the earthquake.

[14] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.
[15] UCERF3: A New Earthquake Forecast for California's Complex Fault System; the UCERF3 analysis uses 6.7 as threshold as it matches the magnitude of the 1994 Northridge earthquake, *available at* http://www.wgcep.org/ucerf3

In addition to safety risks that an earthquake may impose on occupants of buildings, and the financial cost to address building damage, an earthquake has the potential to cause sufficient damage to a manned substation control center building to cause reliability impacts.[16]

Potential consequences from O3 are summarized on an annualized basis in Table II-6. Serious injuries and fatalities are associated with occupants located in the building when the earthquake occurs. Reliability impacts are associated with the potential for the earthquake to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O3, the estimate of annual impacts is .486 serious injuries, .018 fatalities, 42K customer minutes of interruption (CMI), and $419K of financial harm on a mean basis; and 4.827 serious injuries, .181 fatalities, 363K CMI, and $3.9M of financial harm on a tail-average basis.

Table II-6 – Outcome 3 (Moderate Earthquake): Consequence Details[17]

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Customized expert analysis performed by third party based on granular, building-level data (e.g. location, occupied population, condition, replacement cost, etc.).	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.
Model Outputs	NU - Mean	0.49	0.02	42K CMI	$419K
	NU - Tail Avg	4.83	0.18	363K CMI	$3.9M

5. O4 – Buildings Subjected to Catastrophic Earthquake (greater than 6.7)

We analyzed outcome 4 using the same approach as Outcome 3, but at a higher level of earthquake magnitude. In a large earthquake of magnitude 6.7 or greater, there is

[16] Due to this chapter's scope of occupied buildings, the analysis presented here does not include reliability impacts that an earthquake could cause by damaging unoccupied buildings or facilities, especially substation facilities, which are more likely than occupied buildings to have direct reliability impacts to electrical service.

[17] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

greater risk of building collapse and red-tagging (meaning a building does not collapse but can no longer be safely occupied).

Potential consequences from O4 are summarized on an annualized basis in Table II-7. Serious injuries and fatalities are associated with occupants located in the building when the earthquake occurs. Reliability impacts are associated with the potential for the earthquake to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O3, the estimate of annual impacts is 1.502 serious injuries, .075 fatalities, 167K customer minutes of interruption (CMI), and $1.6M of financial harm on a mean basis; and 15.001 serious injuries, .750 fatalities, 1.6M CMI, and $15.3M of financial harm on a tail-average basis.

Table II-7 – Outcome 4 (Catastrophic Earthquake): Consequence Details[18]

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Customized expert analysis performed by third party based on granular, building-level data (e.g. location, occupied population, condition, replacement cost, etc.).	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.
Model Outputs	NU - Mean	1.50	0.08	167K CMI	$1.6M
	NU - Tail Avg	15.00	0.75	1.6M CMI	$15.4M

[18] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

III. Compliance & Controls

Table III-1 maps controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.[19]

Table III-1 – Inventory of Compliance & Controls

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Fire Life Safety Compliance	Not Modeled	Not Modeled	Not Modeled	$ 0.616	$ 0.254
CM2	Electrical Compliance	Not Modeled	Not Modeled	Not Modeled	$ 2.554	$ 0.249
C1	Seismic Building Safety Program	-	O3, O4	All	$ 8.936	$ 0.008
C2	Facility Emergency Management Program	-	O2.2, O3, O4	S-I, S-F	$ -	$ 0.417

Consequence abbreviation: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

A. CM1 – Fire Life Safety Compliance

A Fire Life Safety (FLS) System is an integrated system of components, equipment and sub-systems installed in a building to prevent or reduce the likelihood of fire outcomes that may result in injury, fatality, or property damage. FLS systems and components are typically focused on fire detection, suppression, and/or notification of building occupants.

Buildings have combinations of FLS equipment depending on the building's design and use, and the requirements of the local authorities. The local fire authority has primary jurisdictional approval of the design, components, and configuration of a building's FLS system.

Table III-2 summarizes inspections and testing requirements related to FLS compliance.

[19] Please refer to WP Ch. 4, pp. 4.5 – 4.12 *(Control Mitigation Risk Reduction Effectiveness)* for further details on the data sources and methodology to estimate control effectiveness.

Table III-2 – FLS Compliance Inspections and Tests

Sub-System	Activity Type	Component Tested
Fire Alarm	Annual Visual Inspection	Batteries, sub-panels, initiating devices (heat/smoke detectors), pull stations, horns, strobes, bells.
	Bi-Annual Test	Battery voltage (for non-monitored panels).
Sprinkler System: Wet	Quarterly Visual Inspection	Alarm devices, hydraulic nameplates, gauges, control valves, alarm valves, pipes and fittings, sprinklers, spare sprinklers, fire department connections.
	Annual Visual Inspection	Bracings and hangers, alarm devices, control valve position/operation, main drain test, supervisory flow test.
	5-Year Test	Piping obstruction, concealed accessible spaces, pressure-reducing valves, gauges, fire department connections, sprinklers.
Sprinkler System: Dry Pipe	Annual Test	Priming water test, low air pressure test, quick opening device test, full flow trip test, low point drain test.
	Quarterly Visual Inspection	Valves.
	5-Year Test	Piping obstruction, alarm valve obstruction.
Sprinkler System: Pre-Action	Annual Test	Priming water test, low air pressure test, quick opening device test, full flow trip test, low point drain test.
	Quarterly Visual Inspection	Valve operation.
	5-Year Test	Piping obstruction inspection, alarm valve obstruction inspection.
Sprinkler System: Deluge	Annual Test	Full flow trip test.
Sprinkler System: Gas Suppression	Annual Test	Batteries, sub-panels, initiating devices (heat/smoke detectors), pull stations, horns, strobes, bells.
Foam System	Annual Test	Discharge device, detection system, piping, foam concentrate/solution proportioning, control valve.
	5-Year Test	Full flow trip test.
Fire Pump	Weekly Test	Pump test, PSI check, leak check, packing test.
	Annual Test	Full flow trip test.
	5-Year Test	Piping obstruction, concealed accessible spaces, pressure-reducing valves, gauges, fire department connections, sprinklers.

Following each of the inspections or tests noted above, inspection and testing records document SCE's adherence to the compliance requirement.

Fire extinguishers are also an important component of FLS systems, and SCE makes sure that certification and records for fire extinguishers are up to date (they are renewed on an annual basis per the State Fire Marshall). SCE also performs a monthly physical inspection to validate that fire extinguisher tags reflect current compliance.

B. CM2 – Electrical Compliance

SCE's building electrical compliance activities are primarily dictated by the National Electric Code (NEC). The NEC, which is also known as NFPA 70, is a set of electrical design and installation standards published by the National Fire Protection Association (NFPA). Although the NFPA is not a government organization, many state and local governments (including California at a state level and cities within SCE's service territory) codify NFPA standards as the requirements under their jurisdiction. As noted by the NFPA, "[a]dopted in all 50 states, the NEC is the benchmark for safe electrical design, installation, and inspection to protect people and property from electrical hazards."

NFPA 70E, which was first published in 1979, is a separate but related set of NFPA standards intended to "use policies, procedures, and program controls to reduce the risk associated with the use of electricity." Though the Occupational Safety and Health Administration (OSHA) does not explicitly dictate the use of NFPA 70E, OSHA mandates that employers use industry standards and practices that will protect their workforce from harm. NFPA 70E was developed to help building owners and employers comply with the OSHA requirements.

SCE maintains compliance in all facility operations and construction activities requiring adherence to NFPA 70. For example, new construction projects are inspected by permitting agencies, and electrical projects are performed by licensed electricians. NFPA 70E requirements include activities such as reviewing arc flash information.

C. C1 – Seismic Building Safety Program[20]

Seismic mitigations to improve building safety can be characterized in two categories: structural and non-structural.

Structural mitigation or retrofits involve modifying an existing building to make it more resistant to seismic activity, ground motion, or soil failure. For example, a retrofit could include adding anchors and roof-to-wall straps to existing structures. Retrofits are tailored to specific performance objectives, such as preventing structural collapse and occupant harm or increasing the chance that the building can continue operations after an earthquake.

[20] This control is titled "Seismic Assessment and Mitigation Programs: Non-Electric Facility Mitigation" in SCE's 2018 General Rate Case testimony A.16-09-SCE-07, Vol. 1

Non-structural mitigations are improvements that help prevent large objects (such as storage racks and cabinets) from falling during seismic events. Equipment (e.g., large mechanical, electrical, or plumbing systems) and furnishings that are reinforced or held in place will pose less of a safety hazard both during and after an earthquake. These activities also support faster restoration of operations following an earthquake.

This mitigation focuses on work that exceeds buildings codes and standards. Because codes and standards are typically linked to the point in time when a building was constructed, they may not reflect advances in science and engineering that have informed seismic-related safety improvements. SCE initiated seismic work at a pace of approximately 10 buildings pear year starting in 2016. SCE proposes to continue this pace through the RAMP period.

1. Drivers Impacted

None.

2. Outcomes and Consequences Impacted

This control affects all consequences of O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake). Structural and non-structural retrofits to buildings improve the safety of a building in the event of an earthquake, in addition to reducing the potential for repair costs and operational interruptions.

D. C2 – Facility Emergency Management Program

The Facility Emergency Management program oversees the maintenance of SCE's Emergency Action Plan, and trains employees on proper safety protocols during and after an event such as a fire or earthquake.

SCE has been performing this work in various forms for more than 20 years. Employees are trained to assist with safe egress, to check for injured employees, and to account for all building occupants once they are outside. The program coordinates an annual duck/cover/hold drill in coordination with the statewide Great Shakeout,[21] and manages stocks of emergency aid, water, and food supplies at different building sites.

The Facility Emergency Management program trains and assigns an Emergency Resource Coordinator at each campus as well as Life Safety Coordinators in each occupied building. As a result of regular training and drills, larger buildings are typically evacuated in less than five minutes, and smaller buildings in less than three minutes. The program includes floor sweeps

[21] The California Great ShakeOut is an annual statewide earthquake drill that allows participants to practice safety preparedness procedures as well as reassess preparedness efforts, *available at* https://www.shakeout.org/california/

and roster validations to help ensure that building occupants and visitors are fully accounted for.

1. Drivers Impacted

   None.

2. Outcomes & Consequences Impacted

   This control affects serious injuries and fatalities resulting from O2.2 (Fire or Flare-Up), O3 (Moderate Earthquake), and O4 (Catastrophic Earthquake). Proper evacuation and safety procedures help reduce the potential for injury during and after an earthquake or fire.

IV. Mitigations

Table IV-1 maps each mitigation to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs.[22]

Table IV-1 – Inventory of Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Fire Life Safety Portfolio Assessment	-	O2.2	S-I, S-F	x	x	x
M2	Electrical Inspections	D2	-	-	x	x	x
M3	Wind-Borne Debris Protection	-	O1	All			x
M4	Work(er) Relocation	-	O3, O4	All		x	
M5	Building Replacement	-	O3, O4	All		x	

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.

A. M1 – Fire Life Safety Portfolio Assessment

SCE's FLS approach has been based on compliance requirements, which are typically designed around minimum safety standards and are not necessarily forward-looking.

SCE proposes to systematically identify, compare, and evaluate potential FLS system changes that would exceed compliance requirements. For example, SCE would evaluate whether sprinkler systems are appropriate in some cases in which they are not required.

This mitigation entails developing and implementing a building-level assessment of FLS systems in place across all 170 buildings in scope, and comparing the costs and benefits of changes that would exceed compliance standards.

The assessment would include the identification and execution of work within the RAMP period, which SCE would execute at a pace of approximately two to four building sites per year. (Please note that only a subset of the 170 buildings are expected to be selected for implementing FLS changes.)

1. Drivers Impacted

None.

[22] Please refer to WP Ch. 4, pp. 4.5 – 4.12 *(Control Mitigation Risk Reduction Effectiveness)* for further details on the data sources and methodology to estimate mitigation effectiveness.

2. Outcomes & Consequences Impacted

This mitigation reduces the potential for serious injuries and fatalities associated with O2.2 (Fire or Flare-Up), as FLS systems are designed to suppress the spread of fire and/or provide detection and notification of fires. While this mitigation may also reduce the potential for repair costs due to fire damage, in some cases it is also possible that water damage due to sprinklers can equal the repair costs that would have been incurred if the fire had not been suppressed. Hence, SCE has not assumed a reduction in the financial consequence.

B. M2 – Electrical Inspections

This mitigation entails developing and implementing a portfolio-wide arc flash and thermal infrared survey of building electrical system components, which is identified as an emerging need by industry experts.[23] An arc flash study assesses the maximum incident energy levels of an electrical circuit. An infrared thermography analysis measures excess heat to identify problems before an electrical component fails.[24]

Inspections would be performed on the entire 170 building portfolio on a rolling five-year basis. Inspections would include main breakers, switchgear, subpanels, circuit breakers, and transformers that are downstream of the electrical meter. Scheduling and prioritizing inspections would be informed by internal metrics that have been derived from industry standards such as Facility Condition Index (FCI)[25] and Asset Priority Index (API).[26] Approximately 20% of the buildings in the portfolio would be surveyed on an annual basis.

1. Drivers Impacted

This mitigation reduces D2 (Failure of Building Electrical Systems) by identifying electrical deficiencies that can be corrected before failure occurs.

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[23] Electrical Systems: Don't Get Burned, Facilities Management Journal, March/April 2017, *available at* http://fmj.ifma.org/publication/?i=392368&article_id=2737130&view=articleBrowser&ver=html5#{%22issue_id%22:392368,%22view%22:%22articleBrowser%22,%22article_id%22:%222737130%22}

[24] Because increased heat is a sign of existing or potential failure, infrared serves as an effective diagnostic tool to locate connections in early stages of degeneration.

[25] FCI is a ratio comparing the total deferred maintenance for a building to its estimated replacement value. The higher the ratio, the larger the capital needed to keep the existing building in a functioning state relative to replacement.

[26] API is a tool used in facility management to support portfolio-level decision making that makes the best use of available resources.

2. Outcomes & Consequences Impacted

None, as this is a preventative activity to reduce the potential for failure before it occurs. In some cases, an inspection might identify an electrical component that will be replaced with a newer component that is designed to reduce the extent of fire should failure occur. However, due to the case-by-case nature of such potential improvements, it is not possible at this time to quantify the impact in this analysis with a satisfactory level of accuracy or certainty.

C. M3 – Wind-Borne Debris Protection

This mitigation involves installing a transparent film on windows to improve the window's ability to resist penetration and shattering. The mitigation would be targeted at sites located in extreme wind zones. Approximately 15 of the 170 buildings are located in extreme wind zones.

1. Drivers Impacted

None.

2. Outcomes & Consequences Impacted

All consequences associated with O1 (Building Struck by Objects), as this mitigation increases the strength of the window and its ability to withstand impact from a wind-blown object.

D. M4 – Permanent Work(er) Relocation

In instances where the cost associated with retrofitting a building and/or upgrading components is financially unreasonable, it may be appropriate to permanently relocate the work and the workers to alternate locations. This mitigation can potentially reduce the number of SCE's occupied buildings and the overall building portfolio safety risk exposure.

The San Bernardino Regional Office provides a historical example of how SCE has utilized this type of mitigation. This Regional Office was vacated in 2017 out of an abundance of caution due to its proximity to active earthquake faults. The building was designed to house 250 people, and over 215 office workers were dispersed to alternate locations. Although the facility was constructed according to the building codes and standards in place when it was built in 1958, the seismic risk was considered unacceptable due to advances in both the understanding of seismic risk at this geographic location as well as present-day building engineering and design standards.

This mitigation requires available capacity in other buildings to absorb the work and/or workers that are relocated. For example, destination locations may have limited parking space, or only have temporary occupancy while a relocation into the facility is in progress.[27] In considering available capacity, we must also take into account that unexpected needs may arise (such an unforeseeable condition or event rendering a building inoperable and forcing us to send workers to an alternate location).

Finally, this mitigation is less feasible for buildings where certain types of specialized technical work occurs. Specialized work includes garages, service centers, maintenance and test buildings and substations. This work cannot be easily relocated for reasons that include the need to maintain geographic proximity to work sites as well as policies related to represented employees.

Due to the limitations described above, this mitigation only evaluates a small number of buildings. SCE identified three buildings[28] as potential candidates for this mitigation.

1. Drivers Impacted

Relocating workers from the specific facilities that would be involved in this mitigation does not change the exposure to earthquake or extreme winds. While it is possible that the potential for electrical failure would be reduced when comparing the original location of the workers to the new location, this benefit is difficult to quantify and is unlikely to materially impact the analysis. As such, SCE did not model this potential benefit.

2. Outcomes & Consequences Impacted

All consequences for O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake) are impacted.

E. M5 – Building Replacement

As described above, SCE's seismic program has identified and prioritized the buildings that would benefit from seismic improvements. In some circumstances, replacing a building may be more appropriate when a) the cost of needed upgrades approaches the replacement cost of the building, and b) workers cannot be permanently relocated to other locations. Additionally, buildings that are not currently in scope for C1 may be candidates for replacement due to non-structural reasons such as physical condition or fitness for purpose.[29]

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[27] Under industry best practices, it may be prudent for SCE to maintain a certain amount of unoccupied capacity to allow for future expansion and relocations within the building.

[28] Long Beach Regional Office, Redlands Service Center Kansas Building, and Alhambra Control Center Building D.

[29] The term "fitness for purpose" refers to whether a building is suitable for current and anticipated future needs.

Because buildings with the greatest needs for seismic safety improvements have been included in C1, the incremental safety benefits from this mitigation are relatively modest. Based on operational feasibility, M5 would replace two buildings per year. Prior to deploying this mitigation, SCE would undertake a robust business case analysis to evaluate the full costs and benefits of the effort, including but not limited to safety considerations. For example, SCE has considered replacing buildings in its 2018 GRC.[30]

1. Drivers Impacted

None. Due to the specific facilities that could be included in this mitigation, moving a building's occupants into a new building that would replace the prior site does not change the exposure to drivers. Moreover, because such a move would represent a change in only 1 out of the population of 170 buildings, it would not materially impact the overall analysis and RSE results presented in this chapter.

2. Outcomes & Consequences Impacted

All consequences for O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake), due to replacing an older facility with a current building that meets or exceeds present-day seismic codes and standards.

[30] See SCE 2018 GRC: Exhibit SCE-07, Vol. 3, Workpaper Book A, p. 37.

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V. Proposed Plan

Table V-1 – Proposed Plan

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	**Name**	**Start Date**	**End Date**	**Capital**	**O&M**	**MRR**	**RSE**	**MRR**	**RSE**
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.73	0.015	2.56	0.053
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.226	0.65	0.794
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.87	0.060	2.57	0.177
			Total - Proposed Plan	**$ 52.2**	**$ 17.1**	**1.79**	**0.026**	**5.78**	**0.083**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

SCE's proposed plan is based on continuing its existing seismic program and implementing two new mitigations related to FLS systems and electrical safety.

A significant portion of the risk reduction in this plan comes from the C1 (Seismic Building Safety Program), due to its extensive scope and its role in mitigating a large source of the risk within this chapter. SCE recommends continuing the seismic program as a foundational activity to mitigate one of the most significant risks facing occupants of our buildings. SCE also recommends continuing the facility emergency management program, which is consistent with established industry practice.

The additional activities in the proposed portfolio provide targeted and efficient mitigation of building fire risk (i.e., the electrical and fire safety activities in M1 and M2). Accordingly, these mitigations are included in both Alternative Plans as well.

B. Execution Feasibility

The primary considerations when evaluating the execution feasibility of this plan include internal work coordination and external permitting and scope issues.

With regard to internal work coordination, both costs and operational impacts are minimized when construction activities are consolidated and performed at the same time at the same site. For example, if a building needs structural retrofits, general renovations, and changes to accommodate IT infrastructure, it is more economical to perform all of the work at the same time. In addition to the economies offered by bundling the work, disruption to workers is reduced as the need for temporary facilities and the relocation is minimized.

With regard to permitting and scope issues, SCE cannot always anticipate the response time and changing requirements of local authorities. For example, bandwidth constraints at a municipality may delay key permits, or SCE may be required to expand the scope of work to meet new building codes.[31]

C. Affordability

This Plan's Risk Spend Efficiency (RSE) is the second highest RSE of the three plans considered. Alternative Plan #2 derives a marginally higher RSE than the Proposed Plan (.029 vs. .026) due to the inclusion of M3 (Wind-Borne Debris Protection). SCE considered including M3 in the Proposed Plan, but we ultimately determined that more research is needed to identify the appropriate scope of deployment for this mitigation, and further investigation into window film products is needed.

This plan includes controls and mitigations for which we have a reasonable level of certainty of scope and cost at this point in time.

D. Other Considerations

SCE is not aware of constraints beyond what we mentioned above.

[31] Generally speaking, the requirement to upgrade a building from compliance with the code in force at the time of construction to present-day code could be triggered based on the extent of changes that are undertaken.

VI. Alternative Plan #1

Table VI-1 – Alternative Plan #1

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.74	0.016	2.60	0.054
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.232	0.67	0.811
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.94	0.065	2.73	0.188
M4	Work(er) Relocation	2019	2023	$ 0.5	$ 0.1	0.08	0.127	0.26	0.443
M5	Building Replacement	2019	2023	$ 211.0	$ -	0.14	0.001	0.49	0.002
			Total - Alternative Plan #1	**$ 263.7**	**$ 17.2**	**2.09**	**0.007**	**6.75**	**0.024**

MARS = Multi-Attribute Risk Score.
MRR = Mitigated Risk Reduction.
RSE = Risk Spend Efficiency.

A. Overview

Alternative Plan #1 includes all controls and mitigations as in the Proposed Plan, as well as M4 (Worker Relocation) and M5 (Building Replacement). This plan would require minor adjustments[32] to the volume and sequencing of work performed across the other controls and mitigations due to changes in the building portfolio as a result of implementing M4 (Worker Relocation) and M5 (Building Replacement).

When considered from the safety-oriented perspective of RAMP, the high cost of executing this portfolio (an additional $211.5M in capital) makes it less compelling on a RSE basis. However, as noted in the description of M5 (Building Replacement) in Section IV, SCE has determined that replacing buildings is appropriate in some cases due to the combination of safety and non-safety benefits.

B. Execution Feasibility

This plan shares the same issues as the Proposed Plan with regard to internal work coordination and external permitting and scope issues.

It also includes additional operational considerations (previously discussed in Section IV) such as finding alternative work locations for workers who are displaced due to their building being closed or replaced. M5 (Building Replacement) also presents operational considerations such as the availability of external resources to perform building replacement work.

[32] While this would impact work management practices, it would not have a material impact on the RAMP analysis.

C. Affordability

This plan costs approximately five times more in capital than the Proposed Plan ($263.7M vs. $52.2M), yet only delivers approximately 17% percent greater risk reduction (2.09 vs. 1.79). The difference is due to the high cost of M5 (Building Replacement), which does not have a commensurate risk reduction. As a result, SCE believes the Proposed Plan is a more efficient use of funds based on what we know now.

SCE will continue to evaluate this Alternative Plan as our facilities age and deteriorate. As previously discussed, deteriorating buildings conditions (as measured by the Facility Condition Index) and the criticality of certain facilities (as measured by the Asset Priority Index), may necessitate resorting to M5 (Building Replacement). SCE has, and will continue to, evaluate building replacements as a viable and necessary mitigation for this risk.

D. Other Considerations

None beyond what is mentioned above.

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VII. Alternative Plan #2

Table VII-1 – Alternative Plan #2

Alternative #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.74	0.015	2.59	0.054
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.228	0.66	0.803
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.92	0.064	2.71	0.187
M3	Wind-Borne Debris Protection	2019	2023	$ 0.3	$ -	0.18	0.717	0.59	2.369
			Total - Alternative Plan #2	**$ 52.4**	**$ 17.1**	**2.03**	**0.029**	**6.55**	**0.094**

MARS = Multi-Attribute Risk Score.
MRR = Mitigated Risk Reduction.
RSE = Risk Spend Efficiency.

A. Overview

Alternative Plan #2 includes all controls and mitigations as included in the Proposed Plan, with the addition of M3 (Wind-Borne Debris Protection) to mitigate the risk from wind-borne objects.

While this portfolio is compelling from an RSE perspective, SCE needs to fully evaluate individual building candidates to receive treatment from M3, and to more fully evaluate potential window film products.

B. Execution Feasibility

This plan shares the same considerations as the proposed plan with regard to internal work coordination and external permitting and scope issues.

For M3, the scope of work would be determined by building sites with high exposure to extreme wind speeds (approximately 15 sites). Although the work is not technically complex, timing of the work would be determined by evaluating whether to bundle the work with other projects or initiating it as a standalone effort.

C. Affordability

The RSE of this portfolio is .029, which nearly identical to the RSE of the proposed plan. While the incremental cost of M3 is marginal relative to the remainder of the plan, SCE does not feel it prudent to pursue this mitigation at this time due to the need for further evaluation.

D. Other Considerations

None beyond what is mentioned above.

VIII. Lessons Learned, Data Collection & Performance Metrics

A. Lessons Learned

Data availability was a challenge. Improved data pertaining to specific building components and life cycles would have enhanced the analysis by allowing for asset-specific information. Furthermore, the attempt to analyze existing and future risk levels would have benefited from a greater record of historical data pertaining to specific causes of recorded failures of electrical components. With respect to costs, in some cases current accounting codes were too broad and did not allow for readily available tracking of work at a more detailed level.

SCE is currently migrating to a new facilities management technology[33] that will streamline end-to-end facilities management from service request intake to work orders management to invoice handling and payment. This capability will improve access to data and reporting, thereby addressing some of the data challenges.

B. Data Collection & Availability

SCE has initiated the following efforts to improve data collection for this risk:

- Enhancements to Archibus[34] to improve data collection and integrity related to building occupancy.
- Accounting changes to track costs at a more granular level.

SCE is considering additional efforts to improve data collection:

- Evaluating enhancements to the eComet[35] database system to expand the types of building components being tracked and to include dashboard reporting capabilities.
- Evaluating an increase in participation in the International Facility Management Association (IFMA) to systematically identify and implement industry-standard data collection processes and analytics.

[33] Service Insight 7/JDE.
[34] The Archibus Facility Management System is used to manage real property information and processes, including a comprehensive asset inventory, space planning and management, lease administration, and preventive maintenance.
[35] eCOMET is software that provides data capture, analysis, capital renewal expenditure projections, and reporting.

- Evaluating an expanded effort to track the life cycle of key electrical components, which can inform a replacement strategy based on industry standards.

C. Performance Metrics

SCE currently tracks the following metrics:

- Number of buildings seismically retrofitted for both structural and non-structural purposes.
- Number of evacuation drills and average egress times of buildings.
- Number of emergency coordinators and life safety coordinators trained (relative to goal).
- Number of false fire alarms notifications as a proxy for effectiveness of FLS systems.

SCE is considering additional metrics:

- Age of critical FLS system components beyond manufacturer-specified useful life.
- Number of building electrical component failures per year.
- Percentage (relative to goal) of electrical component replacements per year.
- Percentage (relative to goal) of completed arc flash and infrared inspections.

IX. Appendix A

A. Summary of Buildings In Scope

Table IX-1 categorizes the different types of occupied buildings in terms of their primary function.

Table IX-1 – Summary of Buildings in Scope

Building Category	Category Description	Buildings in Category
Critical Facilities	Facilities containing any operation that, if interrupted, will cause a negative impact on business activities (e.g., data centers).	6
Generation	Buildings that support electric generation facilities owned by SCE (e.g., Big Creek and Mountain View).	4
Headquarters	Office buildings in the Rosemead General Office complex.	4
Office	Facilities primarily used to conduct business relating to administration, clerical services, and other client services not related to retail sales.	34
Service Center	Primarily houses the regional operation and planning functions of SCE's Transmission & Distribution and Customer Service organizational units.	63
Specialty/Garages	Buildings utilized for maintaining SCE's vehicle fleet, including cars, light trucks, cranes, line trucks and gas-powered equipment.	19
Manned Substation	Facilities at 31 substations that house employees (most roles relate to maintenance and operations).	34
Warehouse	Utilized for activities such as storing, testing and deploying electrical meters.	6
	Total	170

B. Supplemental Information on Risks Excluded from this RAMP Chapter

The number and diversity of buildings within SCE's portfolio made it challenging to narrow the scope of the analysis of this risk. Further, the age and condition of these buildings create a variety of hazards that SCE must address that could be unique to individual buildings.

To focus this RAMP chapter on the key safety risks facing our portfolio of occupied buildings, SCE evaluated, but ultimately decided against, several other drivers of risk to our buildings, including:

- Hazardous materials or substances (i.e., asbestos, lead, mold)
- Water inundation due to uncontrolled rapid release of water from a hydro dam

- Water inundation due to extreme rain or natural flooding
- Wildfire

1. Hazardous Materials or Substances

The greatest risk of exposure to hazardous materials, including Asbestos Containing Materials (ACM), occurs when the material is disturbed by intentional activities (e.g., construction) or by unintentional causes (e.g., earthquake). ACM is friable, meaning it is prone to breaking into small pieces when placed under stress or physical contact.

When the disturbance occurs as a result of intentional causes such as construction activities, mitigations are integrated into the activity that causes the disturbance. Prior to undertaking a project that will disturb existing exterior or interior building components, an environmental assessment is conducted to identify potential issues and to mitigate accordingly. For example, SCE's seismic retrofit activities include measures to protect workers and building occupants during construction activities that will disturb ACM or other hazardous materials.

The disturbance can occur due to unintentional situations, such as an earthquake. For the analysis presented in this chapter, the seismic modeling does not include potential impacts associated with ACM disturbance.

2. Water Inundation: Hydro Dam

Water inundation due to an uncontrolled rapid release of water from a hydro dam is not included in this chapter for two reasons. First, the Hydro Asset Safety chapter addresses this risk from the perspective of dams operated by SCE. Second, the safety risk posed by dams that SCE does not operate is either minimal or adequately mitigated (to the extent that SCE can mitigate the risk given that it does not operate the facilities).

SCE identified two facilities—the Santa Fe Dam and the Morris Reservoir—that are operated by other parties but could potentially cause harm to occupants of SCE buildings. The Morris Reservoir is upstream from the Santa Fe Dam, and each holds about 45,000 acre-feet of water. The flood inundation map[36] due to a failure of the Morris Reservoir indicates that SCE buildings would not be significantly impacted.

[36] "Inundation mapping" generally refers to a map that delineates the area that would be flooded by a particular flood event. It includes the ground surfaces downstream of a dam, showing the probable encroachment by water released because of: (a) failure of a dam, or (b) abnormal flood flows released through a dam's spillway and/or other appurtenant pathways for the water. Inundation maps for hydro dams and reservoirs are typically prepared by the facility operator following guidelines set by the regulating authority with jurisdiction. Morris map, *available at*

The inundation map for the Santa Fe Dam indicates that 11 SCE buildings could potentially be affected. However, due to the topography and/or distance from the failure source, the impact would be limited to operational inconvenience and water damage; injuries or fatalities are unlikely.

Because SCE does not operate the Santa Fe Dam or Morris Reservoir, the only mitigation available to SCE[37] is to make sure that it has sufficient ability to notify employees of a pending inundation risk and to implement protocols to respond to early notification or to seek protection onsite. SCE's Security Operations Center notification protocols already provide notifications and response protocols to mitigate these risks.

3. Water Inundation: Rain or Flood

Flooding due to natural causes was excluded due to low exposure, low potential for safety impacts, and redundancy with the Climate Change chapter.

A small number of the buildings in scope for this chapter are located in areas of potential risk due to natural flooding (e.g., flooding not caused by a dam failure). Ten SCE building are located within a 100 year-flood plain area as identified by FEMA.

The topography around these buildings naturally reduces the flood risk to a level of operational inconvenience without significant safety risk. For example, water might enter a building and require an area to be screened off for repairs, but it would not pose a safety risk. Additionally, if a flood were to occur, SCE's existing notification systems should provide adequate time to evacuate employees.

Finally, note that extreme rain events are covered as a driver in the chapter on Climate Change.

4. Wildfire

Wildfire is not addressed in this chapter to avoid redundancy with Chapter 12 (Climate Change) and Chapter 10 (Wildfire). The Climate Change chapter evaluates the risk that extreme wildfire events may pose to SCE assets, which includes SCE buildings. In the Wildfire chapter, wildfire is examined from the perspective of an ignition event that is associated with an SCE worker or SCE asset.

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https://www.ci.azusa.ca.us/DocumentCenter/View/5208/FloodZoneMap2010?bidId; Santa Fe Dam safety information, *available at* https://www.spl.usace.army.mil/Media/Fact-Sheets/Article/477342/dam-safety-program/

[37] SCE notes that, similarly to the operations of the hydro dams in its portfolio, the operators of the Santa Fe Dam and the Morris Reservoir are subject to significant public safety regulation.

5. Additional Comments on Fire Risk

Building fire incidents involving SCE buildings have been extremely rare. In 1980, a warehouse caught fire due to electrical issues. In 1994, a squirrel made contact with energized equipment at a switchyard, which led to a fire that damaged the roof of an SCE building. These two incidents represent the extent of past building fire incidents that SCE was able to identify (excluding wildfires and several small fires that did not involve buildings).

SCE analyzed fire risk by treating it as an outcome that would result from a preceding driver (i.e., the underlying cause of the fire). Table IX-2 shows nationwide data from the U.S. Fire Administration (USFA)[38] on the causes of nonresidential building fires in 2016. SCE used these categories to systematically assess which risk drivers with the potential to result in a fire outcome should be included in the chapter.

Table IX-2 – Nonresidential Building Fire Causes, U.S. (2016)

	Nonresidential Building Fires, U.S., 2016	% of Total
Cause not specified	32,400	33%
Cooking	28,900	30%
Unintentional, careless	10,700	11%
Intentional	9,000	9%
Heating	7,100	7%
Electrical	7,100	7%
Under investigation	1,600	2%
	96,800	100%

Of the fire causes specified in Table IX-2:

- Cooking was excluded due to lack of significant exposure.[39]
- The causes "Unintentional, careless" and "Intentional" are out of scope due to being a result of human action, not building failure. These types of actions are covered in the following chapters: (a) Employee, Contractor & Public Safety, which evaluates the consequences of acts performed by workers; and (b) Physical Security, which analyzes deliberate attempts to cause harm.

[38] USFA is an entity of FEMA.

[39] Four SCE buildings have commercial-level kitchens; each has fire suppression systems that meet compliance standards.

- Space heaters represent the largest source of fires[40] linked to heating-related causes by a substantial margin. To the extent that a fire could be caused by an individual using a personal space heater (which is generally not in conformance with SCE policy), the risk would fall within the scope of the chapter on Employee, Contractor & Public Safety.
- Electrical was included as described above.

[40] Non-Home Structure Fires By Equipment Involved In Ignition, NFPA, J. Hall, Jr., Feb. 2013, *available at* https://www.nfpa.org/-/media/Files/News-and-Research/Fire-statistics-and-reports/Building-and-life-safety/osnonhomefireequipment.ashx

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL® Company

(U 338-E)

Southern California Edison Company

Risk Assessment and Mitigation Phase

Contact With Energized Equipment

Chapter 5

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

Southern California Edison (SCE) delivers electricity to over five million customers through our system of overhead conductor and underground cable. In this chapter, we will address an important safety risk associated with overhead conductor. This risk is members of the public coming into contact with energized overhead conductor. To do this, we developed a risk bowtie structure, quantified risk drivers, triggering events, outcomes, and consequences associated with it, and evaluated the effectiveness of existing controls and new mitigations at mitigating this risk.

SCE has developed three plans to address this risk. The Proposed Plan presented in this chapter best balances risk reduction, execution feasibility, and cost.

B. Scope

The scope of this chapter is defined in Table I-1.

Table I-1 – Chapter Scope

In Scope	• Contact by a member of the public with energized overhead distribution primary conductor, whether that conductor is a wire-down,[1] or remains intact.
Out of Scope	• Contact with energized equipment by SCE employee or contractors.[2] • Contact with energized equipment during attempted theft of SCE equipment or property. • Contact with substation or transmission equipment or conductor.[3] • Fire ignition associated with SCE Overhead Distribution Equipment.[4]

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[1] For purposes of this chapter, wire-down events include situations where overhead conductor is physically on the ground as well as events where overhead conductor is not physically on the ground but is low enough to touch.

[2] Chapter 7 (Employee, Contractor, and Public Safety) addresses the risks associated with SCE employees and contractors contacting energized overhead conductor.

[3] This risk is discussed in Appendix B - Transmission and Substation Safety.

[4] This risk is discussed in Chapter 10 (Wildfire).

C. Summary Results

Table I-2 summarizes the controls and mitigations examined in this chapter, as well as the results of SCE's risk evaluation. The summarized material will be discussed in detail throughout this chapter.

Table I-2 – Summary Results (Annual Average over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Overhead Conductor Program (OCP)	X		X
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	X		
C2	Public Outreach	X	X	X
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor		X	
M2	Comprehensive Branch Line Fusing		X	X
M3	Targeted Underground Conversion			X
M4	Infrared Inspections	X	X	X
M5	Wildfire Covered Conductor Program	X	X	X
Mean (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	7.91	7.91	7.91
	Risk Reduction (MRR)	0.89	0.93	0.93
	Remaining Risk	7.02	6.98	6.98
	Risk Spend Efficiency (RSE)	0.0027	0.0028	0.0027
Tail Average (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	10.24	10.24	10.24
	Risk Reduction (MRR)	0.93	0.97	0.98
	Remaining Risk	9.31	9.27	9.27
	Risk Spend Efficiency (RSE)	0.0029	0.0029	0.0028

Figures represent 2018 - 2023 annual averages.

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.

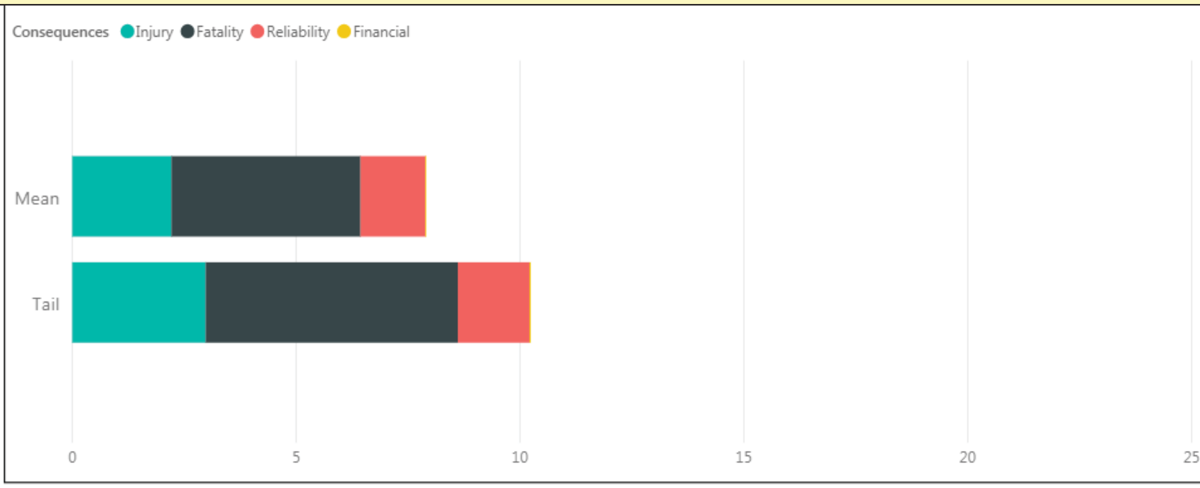
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 below illustrates the composition of the baseline risk. This figure illustrates that the majority of this risk is associated with serious injuries and fatalities. Reliability impacts are also caused by this risk.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

SCE's electrical system includes approximately 106,000 conductor miles of primary overhead distribution conductor. This conductor is installed on distribution poles throughout our service territory. The conductor transmits electricity from distribution substation to distribution substation, and from distribution substation to end-use customers. In areas served by overhead infrastructure, energized distribution conductor is present on nearly every street, alley, thoroughfare, and residential property.

Exposure to the elements, contact with metallic balloons, vegetation intrusion, and windborne debris could all potentially cause an overhead conductor fault and wire-down event. SCE's distribution system is constructed with protection equipment that stops the flow of electricity when a foreign object contacts the line and causes a fault. If the fault is temporary and has not resulted in damage, electricity flow can typically be restored relatively quickly (in seconds or minutes) through an automatic operation referred to as a circuit "reclose."[5] If the fault is permanent or has resulted in damage to infrastructure, then the electricity flow will remain interrupted. This condition is referred to as a circuit "lockout," and requires deploying field personnel to locate and repair the problem.

On a daily basis across SCE's service territory, protection devices successfully open and either reclose or lockout circuits. This maintains reliability while reducing the need to deploy resources to manually reclose line sections. However, SCE has experienced several fatalities as a result of conductor failing in service, falling to the ground, remaining energized, and being contacted by members of the public.

In recent years, SCE has recognized that a more comprehensive program was necessary in order to adequately address the safety risks associated with overhead conductor failure. As a result, in our 2018 GRC[6] SCE proposed a new Overhead Conductor Program (OCP) to replace and mitigate at-risk overhead conductor.

[5] Studies have shown that more than half of faults on overhead distribution systems are temporary faults, or faults that clear themselves without needing additional repairs. Common examples of temporary faults include lightning, wind-driven conductor slapping, and animal contact. In reclosing, a protective device opens to clear a fault and then waits for a pre-determined period of time (say, 15 seconds) before attempting to close. If the fault was indeed temporary, then the protective device closes again, re-energizing the circuit and restoring service to customers served by the circuit. In such case, the circuit has successfully "reclosed."

[6] *See* SCE's Test Year 2018 General Rate Case, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

SCE also presented its initial risk analysis of overhead conductor failure in its 2018 GRC.[7] Specifically, SCE used this risk analysis to evaluate a wide range of mitigation alternatives as well as to shape the scope definition for the mitigations selected. SCE analyzed the equipment installed on the distribution system to identify the types of conductor most commonly involved in overhead conductor failure, or a wire-down event. This effort included additional engineering review of wire-down events; as a result, SCE has made changes to its engineering and design standards to reduce the risk of wire-down events.[8] SCE also reached out to other utilities in California to understand their experience with wire-down events, including drivers, programs, mitigations, and other findings.

Moreover, SCE implemented changes to improve how it tracked and captured event-specific details for overhead conductor failures that resulted in wire falling to the ground. The information is now housed in SCE's Wire-Down (WD) database. We used this information, combined with outage information from our Outage Database and Reliability Metrics (ODRM) system, to identify and quantify drivers, outcomes, and consequences of wire-down events.

In addition to risks associated with wire-down events, there are also risks associated with human contact with intact energized conductor. This can include high-risk workers such as tree trimmers and agricultural workers. There are distinct differences between the risks associated with contact with energized wire-down and risks associated with contact with overhead intact energized conductor. Contact with energized wire-down, by definition, takes place in the presence of equipment failure or fault, while contact with energized intact overhead conductor takes place in the absence of equipment failure or fault.

Therefore, to evaluate the Contact with Energized Equipment risk, SCE has constructed two risk bowties as shown in Figure II-1. These bowties identify two triggering events for this risk: 1) Wire-Down, and 2) Contact with Intact Conductor.

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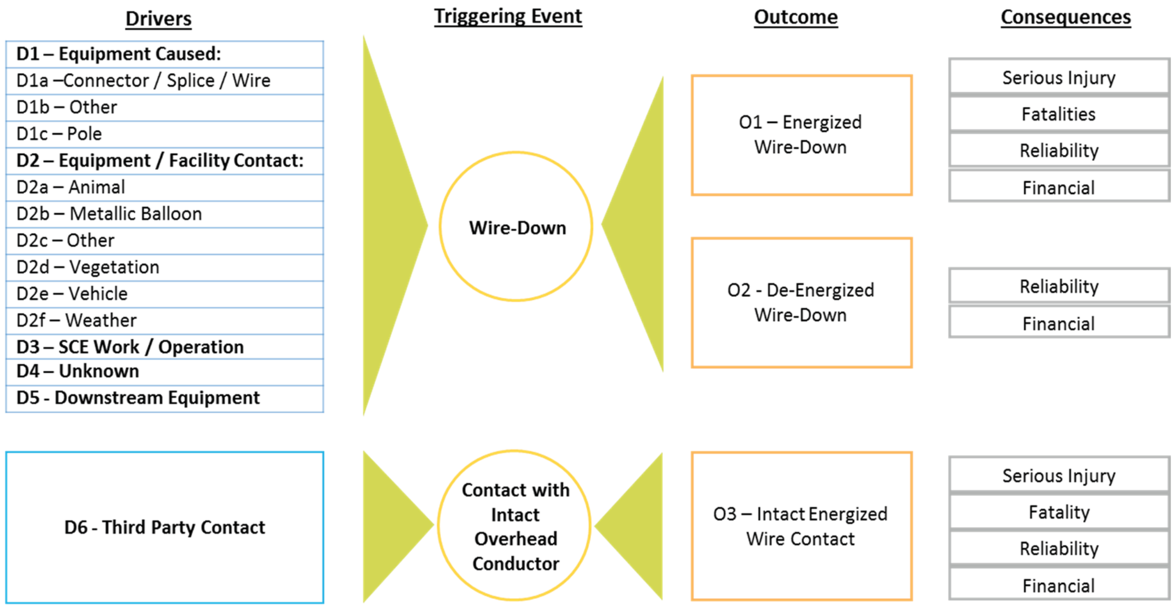
[7] *See* A.16-09-001, Exhibit SCE-02, Vol. 1, pp. 41-44.

[8] Changes to engineering and design standards include the standard installation of a minimum 1/0 AWG for overhead distribution tap lines and 336 ACSR AWG for overhead distribution mainlines for all new installations.

Figure II-1 – Contact with Energized Equipment Risk Bowties



While the risks of Contact with Energized Equipment and Wildfire are distinct, similarities exist between the drivers in the Wire-Down bowtie compared to the drivers in the Wildfire bowtie as shown in Chapter 10 (Wildfire). Although these risks are analyzed independently within each chapter, we discuss the interrelation between Contact with Energized Equipment and Wildfire controls and mitigations in Sections III and IV below.

B. Driver Analysis

SCE identified five primary drivers that lead to a wire-down, the triggering event in the first bowtie. As detailed below, we were able to subdivide two of these drivers (D1 – Equipment Caused and D2 – Equipment/Facility Contact); this greater granularity helped us better understand the causes of this risk.

SCE identified one primary driver that leads to the Contact with Intact Conductor, the triggering event in the second bowtie.

Figure II-2 shows the projected annual frequency counts for each driver across the two bowties. SCE used its internal Wire-Down database[9] to identify the frequency of drivers D1

[9] SCE's Wire-Down database includes several data fields, encompassing conductor material, conductor type, conductor size, event date, circuit name, voltage, cause category, cause type, trigger, structure number, and primary factor.

through D5, which are associated with the first bowtie that address this risk. Data for the frequency of D6 (Third Party Contact), which is associated with the second bowtie, comes from SCE internal records regarding injuries or fatalities involving overhead equipment.[10]

Figure II-2 – 2018 Projected Driver Frequency[11]

Name	Freq	Frequency
D1 - Equipment Cause	206	
D2 - Equipment / Facility Contact	773	
D3 - SCE Work / Operation	7	
D4 - Unknown	168	
D5 - Downstream Equipment	0	
D6 - Third Party Contact	5	

1. D1 – Equipment Cause

The "Equipment Cause" driver represents instances where SCE's equipment fails in service or fails to operate as designed, resulting in a wire-down event. Sub-categories of drivers identify the specific type of equipment that fails.[12] A summary of the annual frequencies of this driver and its sub-drivers is provided in Table II-1 below. This table provides frequencies both as a percentage of this driver category (i.e., D1) and as a percentage of all triggering events (i.e., D1 through D6 combined).

[10] Such events are reported to the Commission in compliance with D.06-04-055 and Resolution E-4184.
[11] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment).*
[12] Please note that the RAMP risk model treats all D1 drivers as a single input, rather than modeling each of the individual sub-drivers separately.

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D1a Connector/Splice/Wire	130	63%	11%
D1b Other	65	32%	6%
D1c Pole	11	5%	1%
D1 Equipment Cause	**206**	**100%**	**18%**

Table II-1 – D1 (Equipment Cause) Frequencies

a. D1a – Connector / Splice / Wire

Connectors and splices are two different types of devices used as a connection for overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector, and spans of conductor are connected to other spans of conductor with a splice. Both types of devices are subject to degradation due to exposure to the elements and can be damaged due to faults, particularly with elevated short circuit duty[13] on the circuit. In the presence of faults, these equipment types can overheat and melt, causing the overhead conductor to fall to the ground.

a. D1b – Other

This driver includes all equipment drivers other than poles and connectors / splices / wires. Examples include failure of transformers, insulators, lightning arrestors, and cross arms. These types of equipment can deteriorate from age, use, and exposure to the elements.

b. D1c – Pole

Pole failures that lead to wire-down events typically occur when there is deterioration at the top of pole. Pole deterioration can take place at any location on a pole. Unless the deterioration is visible, SCE's intrusive pole inspection program and pole loading assessments cannot effectively test for, or detect, deterioration at the top of the pole. Pole failure due to vehicle collision is not included in this sub-driver, but is included in Sub-Driver D2e – Vehicle as described below.

[13] Short Circuit Duty (SCD) indicates the relative strength of a system, typically measured by the fault current (in amps) that the system can supply at any location within the system. For older overhead wire installations, existing levels of SCD can result in increased risk of conductor damage during fault conditions, though it is not currently possible to determine the extent of conductor damage on in-service overhead conductor from previous faults.

2. D2 – Equipment / Facility Contact

The "Equipment/Facility Contact" driver represents instances where a foreign object has made contact with SCE's overhead conductor, resulting in the conductor failing. This driver category includes sub-categories which identify the specific external factor that caused the equipment to fail.[14] A summary of the annual frequencies of this driver category and each sub-category is provided in Table II-2 below. This table provides frequencies both as a percentage of this driver category (i.e., D2) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-2 – D2 (Equipment / Facility Contact) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D2a Animal	53	7%	5%
D2b Metallic Balloons	111	14%	10%
D2c Other	39	5%	3%
D2d Vegetation	171	22%	15%
D2e Vehicle	206	27%	18%
D2f Weather	193	25%	17%
D2 Equipment/Facility Contact	**773**	**100%**	**67%**

a. D2a – Animal

Animals, such as birds and squirrels, are frequently seen sitting or walking on overhead conductors. In some instances, an animal makes the fatal move of contacting two phases of a circuit or contacting one phase of a circuit and a grounded portion of the circuit, causing a fault. Similar to faults caused by a metallic balloon, the result can be circuit damage, overheating, or fire, or explosion.

b. D2b – Metallic Balloons

Foil, foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[15] has recognized this, and requires that all helium-filled metallic balloons be weighted to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines, it can create a short circuit. The short circuit can trigger circuit damage, overheating, fire, or an explosion.

[14] Please note that the RAMP risk model treats all D2 drivers as a single input, rather than modeling each of the individual sub-drivers separately.
[15] *See* Cal. Penal Code § 653.1. (Foil Balloon Law).

c. D2c – Other

The Other sub-category includes overhead conductor failures that are driven by malicious mischief or other actions by the public. This includes gunshot damage to conductors and contact from various objects such as drones.

d. D2d – Vegetation

The vegetation sub-category includes overhead conductor failures driven by contact with vegetation. Vegetation may grow into the primary lines when homeowners plant climbing vines to hide a power pole, or when a branch or tree breaks and falls into SCE's overhead conductor. Airborne vegetation, particularly palm fronds, can also come in contact with SCE's overhead conductor, resulting in damage.

e. D2e – Vehicle

The vehicle sub-category includes overhead conductor failures driven by motorized vehicles. This can occur when a passenger car, moving van, or garbage truck collides with our electrical equipment. The failure can result from overhead lines "slapping" together due to the impact of the collision, or from a pole being knocked over or broken from the impact.

f. D2f – Weather

The weather sub-category includes contact with overhead lines as a result of weather conditions, including wind and lightning. During windy conditions, debris is blown into the lines. This results in outcomes ranging from momentary outages to downed conductor. This driver is identified by SCE personnel based on evidence available at the time of the event, such as debris in the lines, pitting of the conductor, or burned matter in proximity to the outage during declared storm events.[16]

3. D3 – SCE Work / Operation

The SCE Work / Operation driver includes activities where SCE or its contractors were responsible for a wire-down. This includes improperly operating equipment during construction, repair, switching, or other activity. The distinction between this driver and the risks assessed in the Worker Safety chapter is that the events in this chapter include consequences associated with damage to SCE infrastructure, but not the consequences associated with any injuries to SCE workers or contractors that may occur. A summary of the annual frequency of this driver category

[16] A storm event is defined as an SCE distribution circuit outage(s) resulting from wind, rain, lightning, heat, or fire.

is provided in Table II-3 below. This table provides frequencies both as a percentage of this driver category (i.e., D3) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-3 – D3 (SCE Work / Operation) Frequencies			
Driver Name	**Annual Frequency**	**Percentage (Category)**	**Percentage (All Triggering Events)**
D3 SCE Work/Operation	**7**	**100%**	**Less than 1%**

4. D4 – Unknown

In some circumstances, the cause of a wire-down event is not identifiable when SCE personnel arrive at the site. This can occur for a variety of reasons. Examples include emergency personnel securing the area prior to SCE's arrival, or the offending object being blown or thrown from the location. It is also possible that there is no apparent cause for the failure, and rather than entering a "best guess," the cause is simply categorized as unknown. A summary of the annual frequency of this driver category is provided in Table II-4 below. This table provides frequencies both as a percentage of this driver category (i.e., D4) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-4 – D4 (Unknown) Frequencies			
Driver Name	**Annual Frequency**	**Percentage (Category)**	**Percentage (All Triggering Events)**
D4 Unknown	**168**	**100%**	**14%**

5. D5 - Downstream Equipment

A Downstream Equipment-caused failure is the result of failure of other equipment installed on or connected to the circuit. Simply stated, if there are two pieces of equipment installed on a circuit, the piece of equipment farther from the substation is "downstream" of the piece of equipment closer to the substation. When the downstream equipment fails, high levels of fault current travel a path from the substation through the distribution circuit to the point of fault. These high levels of fault current can damage upstream equipment or conductor along the path, increasing both the immediate and the future probability of equipment failing.

SCE has included D5 in the bowtie shown above because, in recent years, SCE has experienced specific instances of upstream wire-down events associated with downstream faults. These faults can sometimes be very difficult to identify separately, and are implicitly included in D1, D2, and D4 previously described. Although we included Driver D5 in the bowtie for visibility, Driver D5 was modeled with a zero event per year frequency to avoid duplicate representation of the associated risk. A summary of the annual frequency of this driver category is provided in Table II-5 below. This table provides frequencies both as a percentage of this driver category (i.e., D5) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-5 – D5 (Downstream Equipment) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D5 Downstream Equipment	**modeled as zero annual frequency (implicitly included in other equipment failure drivers)**		

6. D6 - Third Party Contact with Intact Lines

D6 includes events where an individual makes contact with energized intact overhead conductor. For example, this driver includes events where a tree trimmer touches an energized conductor with a pruning tool. This contact occurs when there has been no failure of overhead equipment.

The data for Third Party Contact with Intact Lines frequency is based on SCE internal records regarding injuries or fatalities involving overhead equipment. The events which were identified as contact with intact conductor were included in the count for this driver. SCE identified an average of approximately five events per year from 2008 through 2016. A summary of the annual frequency of this driver category is provided in Table II-6 below. This table provides frequencies both as a percentage of this driver category (i.e., D6) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-6 – D6 (Third Party Contact) Frequency

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D6 Third Party Contact	**5**	**100%**	**Less than 1%**

C. Triggering Event

SCE has identified two triggering events for the risk of Contact with Energized Equipment.

1. **Wire-Down** – This results in conductor falling to the ground, or becoming disconnected from the system in a manner that would allow the public to come in contact with it. This triggering event is shown in the first bowtie

in Figure II-1. Based on SCE's Wire-Down database, this triggering event has an average frequency of 1,154 events per year.

2. **Contact with intact overhead conductor** – This event occurs when an individual, or third party, makes contact with SCE's overhead conductor while the conductor is operating and situated as designed. Based on SCE internal records, this triggering event has an average frequency of five events per year.

D. Outcomes & Consequences

SCE identified three outcomes that represent the basic conditions existing when overhead conductor fails in service and falls to the ground, or when the public makes contact with intact overhead conductor. These outcomes, and their associated likelihood of occurrence, are shown in Figure II-3.

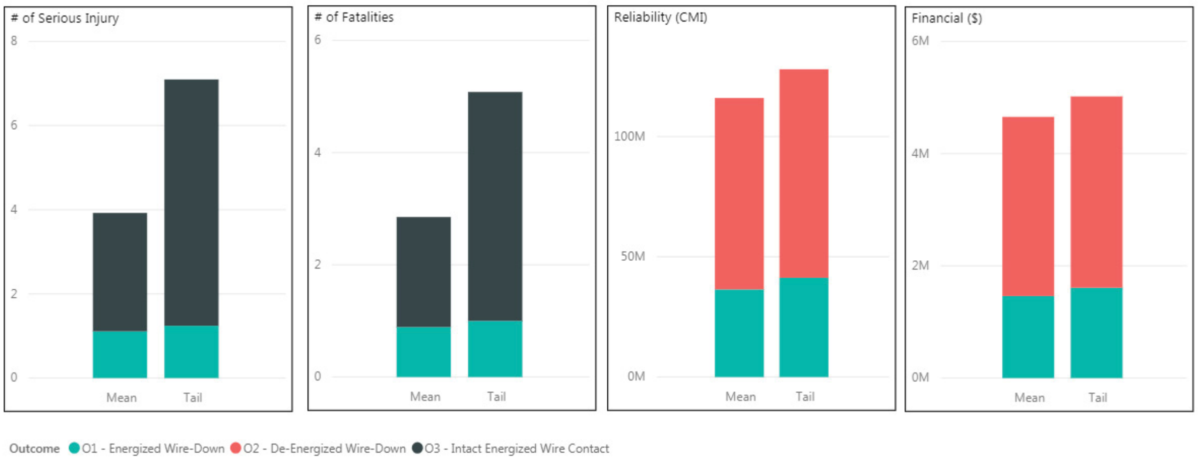
Figure II-3 – 2018 Outcome Likelihood[17]

Name	%	Percent
O1 - Energized Wire-Down	31.3 %	
O2 - De-Energized Wire-Down	68.3 %	
O3 - Intact Energized Wire Contact	0.4 %	

Further, Figure II-4 illustrates the composition of the modelled baseline risk in terms of each consequence. As shown, the primary safety impact of this risk results from the occurrence of O3 (Intact Energized Wire Contact). Notably, O1 (Energized Wire-Down), also results in safety impacts, and also contributes to reliability and financial impacts. The sections that follow detail the inputs used to derive these results.

[17] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)*.

Figure II-4 – Modelled Baseline Risk Composition by Consequence (NU)



1. O1 – Energized Wire-Down

This outcome occurs when a wire-down event has taken place, protective devices have not detected the wire-down condition, and manual intervention is required to interrupt the energized wire-down event. SCE's distribution system is designed and built with protection to stop the flow of electricity under fault conditions, to lockout under conditions of permanent faults or equipment damage, and to reclose under conditions of temporary faults which do not cause infrastructure damage. This protection is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

However, under certain conditions, wire-down events can be difficult to detect by protective devices. For example, this can occur when a wire-down event takes place on high-resistance surfaces such as asphalt, concrete, or very sandy or rocky soils. These conditions are referred to as high impedance fault conditions and can result in fault current magnitudes lower than that what can readily be detected. High impedance fault conditions with wire-downs may not be automatically cleared by protective devices. These conditions may need to be detected through other means such as customer calls, 911 calls, or circuit patrol activities. These conditions also may need to be interrupted by manual intervention of system operators. A summary of the consequences modeled for O1 (Energized Wire-Down) is shown in Table II-7.

***Table II-7 – Outcome 1 (Energized Wire-Down): Consequence Details*[18]**

Outcome 1		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Incidents involving SCE overhead conductor that resulted in serious injuries, from 2008 – 2016.	Incidents involving SCE overhead conductor that resulted in fatality, from 2008 – 2016.	Actual wire-down outage events as analyzed within SCE ODRM Database.	Average cost of equipment repair resulting from wire-down events.
Model Outputs *(Annual Average)*	NU - Mean	1.1	0.9	36,434,141	$1,461,503
	NU - Tail Avg	1.2	1.0	41,273,501	$1,609,341

2. O2 – De-Energized Wire-Down

O2 considers wire-down events where protective devices have detected the wire-down condition and automatically de-energized the wire-down event. As described previously, SCE's distribution system is built with protection designed to stop the flow of electricity under fault conditions, to lockout under conditions of permanent faults or equipment damage, and to reclose under conditions of temporary faults that do not cause infrastructure damage. This protection is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

As a result of the protective device operation, safety impacts are not typically associated with this outcome.[19] Therefore, SCE has not modeled any safety consequences in this outcome. A summary of the consequences modeled for O2 (De-Energized Wire-Down) is shown in Table II-8.

[18] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

[19] Some de-energized wire-down events could be described as "briefly-energized" events. This would be the case where wire is on the ground but only in an energized state during the response time of circuit protective devices. These protective devices typically clear faults in fractions of a second, so the relative risks of "briefly-energized" wire-down events are expected to be low. SCE intended to include a separate "briefly-energized" outcome for this risk analysis, but found that inadequate data exists to identify the number of times that de-energized wire-down events also have a "briefly-energized" characteristic.

Table II-8 – Outcome 2 (De-Energized Wire-Down): Consequence Details[20]

Outcome 2		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	N/A	N/A	Actual wire-down outage events as analyzed within SCE ODRM Database.	Average cost of equipment repair resulting from wire-down events.
Model Outputs *(Annual Average)*	NU - Mean	N/A	N/A	79,598,077	$3,192,980
	NU - Tail Avg	N/A	N/A	86,711,104	$3,409,468

3. O3 – Intact Energized Wire Contact

This outcome occurs when human contact with intact overhead conductor results in serious injury or fatality, and/or and damage to SCE's electrical system. This can occur when overhead conductor is contacted by someone working in close proximity to the line, such as a tree trimmer, making contact. Reliability and Financial consequences have been excluded from modeling. A summary of the consequences modeled for Outcome O3 (Intact Energized Wire Contact) is shown in Table II-9.

[20] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

Table II-9 – Outcome 3 (Intact Energized Wire Contact): Consequence Details[21,22]

<table>
<tr><th colspan="2" rowspan="2">Outcome 3</th><th colspan="4">Consequences</th></tr>
<tr><th>Serious Injury</th><th>Fatality</th><th>Reliability</th><th>Financial</th></tr>
<tr><td>Model Inputs</td><td>Data/sources used to inform model inputs</td><td>Incidents involving SCE overhead conductor that resulted in serious injuries, from 2008 – 2016.</td><td>Incidents involving SCE overhead conductor that resulted in fatality, from 2008 – 2016.</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="2">Model Outputs (Annual Average)</td><td>NU - Mean</td><td>2.8</td><td>2.0</td><td>N/A</td><td>N/A</td></tr>
<tr><td>NU - Tail Avg</td><td>5.9</td><td>4.1</td><td>N/A</td><td>N/A</td></tr>
</table>

[21] As SCE's ODRM does not adequately capture reliability impacts associated with this outcome, SCE does not model reliability for this outcome as part of this RAMP analysis. SCE expects reliability impacts to be small.

[22] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

III. Compliance & Controls

SCE has programs and processes in place that serve to control the risk today. Four of these controls are compliance activities, and accordingly not modeled in this risk analysis. In addition to these compliance activities, three additional controls are modeled in this risk analysis. These compliance activities and controls are shown in Table III-1.

***Table III-1 – Inventory of Compliance and Controls*[23,24]**

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP) Replacements	Not Modeled	Not Modeled	Not Modeled	$ 273.9	$ 30.9
CM2	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$ -	$ 84.3
CM3	Overhead Detailed Inspection, Apparatus Inspections, and Preventive Maintenance	Not Modeled	Not Modeled	Not Modeled	$ -	$ 36.0
CM4	Intrusive Pole Inspections and Pole Loading Assessments	Not Modeled	Not Modeled	Not Modeled	$ -	$ 6.0
C1	Overhead Conductor Program (OCP)	D1a-b, D2a-d,f	-	-	$ 138.7	$ -
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	D1a-b, D2a-d,f	O1	S-I, S-F	$ -	$ -
C2	Public Outreach	-	O1, O3	S-I, S-F	$ -	$ 5.1

Consequence Abbreviation: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP)

SCE's Distribution Deteriorated Pole Remediation Program[25] captures the costs to replace or stub[26] distribution poles which have failed an intrusive pole inspection. The Distribution Pole Loading Program (PLP)[27] captures costs to assess all poles within SCE's service territory and

[23] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)* and WP Ch. 5, pp. 5.12 – 5.22 *(Mitigation Effectiveness Workpaper)*.

[24] Note that for simplicity, SCE shows all recorded costs for OCP in C1 (and not also in C1a). While SCE has not historically used covered conductor in the OCP program, C1a will further the objectives of OCP (just using a different technology).

[25] *See* A.16-09-001, Exhibit SCE-02, Vol. 9, pp. 30-44.

[26] Stub – steel stubbing which reinforces the base of the pole (please see A.16-09-001, Exhibit SCE-02, Vol. 9, p. 34).

[27] *See* A.16-09-001, Exhibit SCE-02, Vol. 9, pp. 10-29.

replace those which fail the applied wind-loading measurement. The costs for both programs are recovered through SCE's Pole Loading and Deteriorated Pole Balancing Account (PLDPBA).

These two programs proactively identify poles that represent an increased probability of pole failure. Through these programs, SCE takes action to replace such poles with new assets that meet pole design standards and criteria. Thus, this compliance control reduces the frequency of pole-related drivers of wire-down events.

B. CM2 – Vegetation Management

Vegetation Management including pruning and removing trees that are in proximity to transmission and distribution high-voltage lines. Vegetation Management also encompasses weed abatement around select overhead structures that may pose a hazard to power lines. These activities are mandated by regulation. This compliance-related work is distinct from the incremental Expanded Vegetation Management mitigation discussed in the Wildfire Chapter. [28]

SCE manages vegetation in accordance with several regulations, including General Orders (GO) 95 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. These regulations require SCE to manage vegetation near its wires. SCE engages a contractor to trim and remove trees and weeds, and handle other activities, to comply with these requirements.

All of the trees in inventory are inspected annually. During these inspections, any trees or vegetation that need to be remediated to maintain the required distances from high-voltage lines are then scheduled to be pruned or removed. In addition, hazard trees, such as overhangs in high fire areas, and damaged or diseased trees are also identified for pruning or removal. Sometimes SCE must trim trees more frequently to continue to meet the Commission's requirements tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards. SCE is exploring an Expanded Vegetation Management program for high fire risk areas, as described in detail in the Wildfire Chapter.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle infestation or resulting from California's Drought Order. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying, or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent

[28] This compliance control is also represented in the Wildfire chapter as CM1. As such, this compliance control serves to affect the risk of both Contact with Energized Equipment and Wildfire.

encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve.

C. CM3 – Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance

SCE's Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance are activities included under SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of GO 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety and maintains system reliability; and (3) delivers overall greater safety value for each dollar spent by allowing SCE to focus its limited resources on higher priority risks. These activities address all distribution overhead assets in the SCE system.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and its potential for impact on safety and reliability, considering various factors such as facility or equipment loading, location, accessibility, and climate. DIMP enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's direction under GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify and rate conditions observed considering the factors discussed previously. Highest priority items requiring immediate action are assigned Priority 1. Priority 2 items do not require immediate action, but require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired or temporarily repaired and reclassified as a lower priority item. Priority 3 items are lower priority items that involve little or no safety or reliability risk. SCE responds to Priority 3 conditions by taking action at or before the next detailed inspection, which may include re-inspection, reassessment, or repair. These maintenance priorities are also utilized by Troublemen when responding to trouble calls and emergency situations. A summary of the DIMP maintenance priority levels is provided in Table III-2.

Table III-2 – Summary of Maintenance Priority Levels

Category	Safety/Reliability Issue Identified	Condition Details	Action
Priority 1	Yes	Immediate action required	Same day/immediate action
Priority 2	Yes	Immediate action not required	Action within 0-24 months (non High Fire Areas) Action within 0-12 months (High Fire Areas)
Priority 3	No	Specific GO 95/128 issue identified	Action at or before next detailed inspection
none	No	No GO 95/128 issue identified	Monitor condition during course of inspection cycles

These activities proactively identify conditions of existing assets that require mitigation to prevent failure. This compliance control performs such mitigations and reduces the frequency of equipment-related drivers of wire-down events.

D. CM4 – Intrusive Pole Inspections and Pole Loading Assessments

These programs involve inspecting or assessing existing distribution poles to execute the activities described in the Distribution Deteriorated Pole Remediation Program and PLP described above. As an enabling activity for compliance control CM1 above, this control helps reduce the frequency of pole-related drivers of wire-down events.

1. Intrusive Pole Inspections

SCE established the distribution pole inspections program to comply with GO 165, which became effective in 1997. GO 165 requires intrusive inspections for all poles at least 15 years old to be completed within 10 years of program inception. Thereafter, it requires all poles to be intrusively inspected by the time they are 25-years old and then re-inspected at least once every 20 years. SCE completed its first cycle of intrusive inspections in 2007.

GO 165 defines intrusive inspections as "involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading." "Intrusive" inspections involve drilling into the pole's interior to identify and measure the extent of internal decay, which is typically undetectable with external observation alone. SCE's inspection standards describe six types of inspections satisfying this definition which apply different combinations of digging, boring, and sounding depending on the type of pole and its setting.

Intrusive inspectors may also perform visual inspection on poles that are in the inspection grid but that are younger than 15 years old, or that have already had an intrusive inspection within the last 10 years, to look for signs of obvious external damage such as damage from vehicles or woodpeckers.

2. Pole Loading Assessments

Pole loading assessments are performed to determine a pole's safety factor. Pole loading assessments require a field assessment and a desktop analysis to calculate each pole's safety factor. Inputs include the physical attributes of the pole, its attachments, and local weather conditions. The field assessment measures or validates the pole's attributes (such as species and type) and the size and equipment it supports.

E. C1 – Overhead Conductor Program (OCP)

SCE's OCP includes both reconductoring and installation/replacement of Branch Line Fuses.[29] OCP is an existing control that SCE began performing in 2015. In SCE's 2018 GRC[30] the Overhead Conductor Program (OCP) was proposed as a new program to implement these mitigations together and address the public safety risk associated with wire-down events.

Central to OCP strategy is an understanding of short circuit duty (SCD). Generally, SCD indicates the relative strength of a system, typically measured by the fault current (in amps) that the system can supply at any location within the system. For older overhead wire installations, existing levels of SCD can result in increased risk of conductor damage during fault conditions, although it is not currently possible to determine the extent of conductor damage on in-service overhead conductor from previous faults.

The OCP addresses this problem by reconductoring smaller-gauge wire to larger-gauge wire that reduces the risk of conductor damage during fault conditions, and installing new protective devices such as branch line fuses where appropriate. The OCP also addresses other deteriorated or corroded equipment such as crossarms, poles, and connection hardware.

Consistent with existing OCP scoping practice, C1 is modeled as including the use of bare overhead conductor and representing 100% of the OCP expenditures for years 2018 through 2020. Because SCE also anticipates future use of covered conductor in non-High Fire Risk Areas (HFRA), C1 is modeled as representing only 90% of the OCP expenditures for years 2021 through 2023. The remaining 10% of the OCP expenditures for years 2021 through 2023 is included in C1a "Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor" as described below. At this time, SCE does not know the exact percentages of bare versus covered

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[29] Branch Line Fuses are protective devices that are designed to clear faults on the system.
[30] *See* A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

conductor for future OCP projects in non-HFRA. The 90% and 10% values for years 2021-2023 are assumed percentages for modeling purposes.

1. Drivers Impacted

The OCP impacts the triggering event frequency associated with Drivers D1 (Equipment Cause), and D2 (Equipment /Facility Contact).[31]

The OCP will reduce the frequency of wire-down events associated with D1 by reducing the frequency of faults. This is because the OCP replaces small, spliced, or damaged conductor with larger, more resilient conductor. The OCP will reduce the frequency of wire-down events associated with Driver D2 not by reducing the frequency of faults, but by reducing the number of faults that lead to wire-down events. Faults listed in D2 are external events that will continue to occur regardless of the OCP. However, the upgrades we perform in OCP will create a more resilient system that will be less susceptible to damage as a result of such faults.

2. Outcomes and Consequences Impacted

The OCP will not impact outcomes or consequences in the risk model.

F. C1a – Overhead Conductor Program (OCP) Using Targeted Covered Conductor

This control assumes that going forward, a small portion of the OCP will be built using covered overhead conductor on a targeted basis.

Covered conductor is overhead conductor enclosed in a high-density polyethylene covering, and is intended to prevent faults caused by contact from tree and other vegetation, contact with metallic balloons, and other types of contact. Use of covered conductor would help preventing certain types of faults, and therefore would reduce wire-down events and intact conductor failures. Covered conductor's partial insulation also provides some degree of protection against safety incidents associated with humans contacting overhead lines.

C1a assumes that SCE will implement a change in the OCP scoping tenets to identify targeted locations appropriate to be built using covered conductor instead of bare conductor. "Targeted locations" refers to locations with higher expectation of faults on bare conductor due to contact with foreign objects such as balloons, vegetation, and animals. SCE has not yet defined these exact scoping tenets, so SCE assumes that these tenets would begin influencing scope in 2021. Until we have more definitive information around these scoping tenets, SCE assumes that C1a would represent 10% of the OCP expenditures in years 2021 through 2023.

[31] Specifically, C1 affects the following sub-drivers: D1a (Connector/Splice/ Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

This 10% assumption is specific to non-HFRA and is mutually exclusive from what is proposed in the Wildfire Chapter.

1. Drivers Impacted

The OCP using Targeted Covered Conductor impacts the same drivers addressed by the OCP, namely: D1 – Equipment Cause, and D2 – Equipment / Facility Contact.[32] However, the OCP using Targeted Covered Conductor assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the OCP using Targeted Covered Conductor assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b and D2d respectively).

2. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this control was modeled as reducing the safety consequences associated with Outcome O1 (Energized Wire-Down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor when an event involves contact with intact overhead conductor (O3). However, as shown in Figure II-3, O3 has a significantly smaller outcome percentage than either O1 or O2. Therefore, as a simplifying assumption and for purposes of this initial RAMP report, SCE did not model any impact on the safety consequences associated with Outcome O3.

G. C2 – Public Outreach

This control includes two activities: (1) Public Safety Outreach, and (2) At-Risk Worker Safety Outreach.

Public Safety Outreach focuses on educating and informing the public on actions to take and avoid when encountering a downed electrical wire. Examples of these outreach efforts include: billboards, television and radio announcements, signage on SCE vehicles, community outreach, information distributed at community events. SCE personnel also work with elementary schools to teach children proper safety around electrical lines. This interaction with young students encourages them to share the information with their families, providing greater reach for the message of safety around energized lines.

[32] Specifically, C1a affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

The At-Risk Worker Safety Outreach provides mailers, flyers and other outreach to third-party contractors, agricultural customers, first responders, and others to inform of the dangers of working around energized equipment, especially overhead conductor. Effectiveness of these efforts are reviewed periodically through analysis of retention rates, recall, open/read rates, and other measures of public awareness.

1. Drivers Impacted

Public Outreach would be expected to reduce the frequency of public contact with intact conductor. Given the differences between the two bowties (see Figure II-1) and the RAMP model structure, SCE chose to represent Public Outreach as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes and Consequences Impacted

SCE models Public Outreach as reducing the safety consequences associated with Outcome O1 (Energized Wire-Down) in the top bowtie. This is based on the assumption that energized wire-down would be less likely to result in serious injury or fatality consequences through proactive messaging, education, and awareness for how to work around, respond to, and avoid contact with energized conductor.

SCE models Public Outreach as also reducing the safety consequences of Outcome O3 (Intact Energized Wire Contact) in the bottom bowtie. This was intended to mimic the equivalent risk reduction that would expected from a reduction in frequency of third party contact with intact lines.

IV. Mitigations

In addition to compliance and control activities mentioned above, SCE has identified potential new and innovative ways to mitigate this risk, to further reduce the frequency and/or impact of the risk event. All of these activities are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[33]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	D1a-b, D2a-d,f	O1	S-I, S-F		X	
M2	Comprehensive Branch Line Fusing	D1b, D2a,c,d,f	-	-		X	X
M3	Targeted Underground Conversion	D1,D2,D3,D4	-	-			X
M4	Infrared Inspections	D1a	-	-	X	X	X
M5	Wildfire Covered Conductor Program	D1a-b, D2a-d,f	O1	S-I, S-F	X	X	X

Consequence Abbreviation: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period. Mitigations are modeled in this report..

A. M1 - OCP Using Covered Conductor

1. Description

This mitigation is specific to SCE's non-HFRA and is an alternative to the combination of C1 (OCP) and C1a (OCP utilizing targeted covered conductor). As previously described, C1 represents 100% of the planned OCP expenditures in 2018-2020 and 90% of the planned OCP expenditures in 2021-2023 using bare conductor, and C1a represents the remaining 10% of the OCP expenditures in 2021-2023 using covered conductor. In this mitigation alternative, M1 assumes that 100% of the planned OCP expenditures in years 2018-2023 would entirely use covered conductor instead of bare conductor.

2. Drivers Impacted

M1 impacts the same drivers addressed by the OCP (C1), namely D1 (Equipment Caused) and D2 (Equipment / Facility Contact).[34] However, the OCP using Covered Conductor

[33] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)* and WP Ch. 5, pp. 5.12 – 5.22 *(Mitigation Effectiveness Workpaper).*

[34] Specifically, M1 affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the OCP using Covered Conductor assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b, and D2d respectively).[35]

3. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this mitigation was modeled as reducing the safety consequences associated with outcome O1 (energized wire-down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor in an event involving contact with intact overhead conductor (outcome O3). However, since O3 is such a small percentage of all of the modeled outcomes, SCE concluded that this effect would be negligible in the overall risk analysis. Therefore, as a simplifying assumption, SCE did not model any impact on the safety consequences associated with outcome O3.

B. M2 - Comprehensive Branch Line Fusing

1. Description

Comprehensive Branch Line Fusing is a short-term program that would target all unfused branch, or tap, lines in SCE's non-HFRA. Branch Line Fuses are protective devices that are designed to clear faults on the system limiting the number of customers impacted by the fault. With the addition of new Branch Line Fuses, faults can clear faster, and the energy associated with faults will be reduced as a result. This reduced energy results in less damage to overhead wire and decreased probability of conductor failure and wire-down.

This is a conceptual mitigation, and at this time SCE does not know exactly how many Branch Line Fuses would be installed throughout the system under such a program. For modeling purposes, SCE assumed that approximately 15,000 new Branch Line Fuses would be installed in the non-HFRA of the SCE system through 2023 as part of this mitigation. For a discussion of fusing mitigations within HFRA, please see the Wildfire Chapter.

[35] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)*.

2. Drivers Impacted

Comprehensive Branch Line Fusing impacts the triggering event frequency associated with drivers D1 (Equipment Cause), and D2 (Equipment / Facility Contact).[36]

Comprehensive Branch Line Fusing would reduce fault energy associated with system faults, and thereby reduce the frequency of wire-down events caused by fault-related drivers. The concept of fault energy can be described as the electric system's natural reaction to fault conditions. Dominant factors for fault energy are the time duration and the magnitude of electrical current during a fault. Branch Line Fusing decreases the time duration of faults, and therefore decreases the fault energy. This helps reduce the probability of equipment damage and wire-down due to faults.

3. Outcomes and Consequences Impacted

Comprehensive Branch Line Fusing will not impact outcomes or consequences in the risk model.

C. M3 – Targeted Underground Conversion

1. Description

This mitigation is specific to SCE's non-HFRA and is an alternative to C1a (OCP utilizing targeted covered conductor). Targeted Underground Conversion would involve the conversion of portions of existing overhead circuits or lines to underground circuits or lines. While C1a assumed that 10% of the OCP expenditures would use covered conductor, M3 assumes that 10% of the OCP expenditures would be used for targeted underground conversion.

An overhead to underground conversion involves removing all aboveground equipment, such as poles, conductor, transformers, switches, etc., and then installing underground conduit, cable, vaults, manholes, transformers, switches, etc. Undergrounding electric facilities can also be challenging and may require multiple designs based on specific geographic factors. This amount of work and challenges make undergrounding a relatively high cost mitigation.

In the scope of this risk analysis as previously described, targeted underground conversion would address more overhead risks than covered conductor.[37] However, targeted

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[36] Specifically, M2 affects the following sub-drivers: D1b (Other), D2a (Animal), D2c (Other), D2d (Vegetation), and D2f (Weather).

[37] The scope of this risk analysis was defined in terms of overhead assets only. Covered conductor is an overhead asset; underground conversion eliminates overhead assets and replaces them with underground assets. The inherent risks associated with underground assets were not included in this analysis.

underground conversion would also be significantly more expensive than covered conductor. SCE modeled M3 as a mitigation alternative to C1a to evaluate whether the additional benefits of underground conversion would be large enough to justify the additional costs. For comparison purposes, M3 would addressing approximately 4.6 miles per year at the same annual cost that C1a would use to address approximately 27 circuit miles per year.

SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C.[38] In cities where undergrounding is required, SCE will install all new construction in compliance with the city's requirements. This would be a new mitigation for SCE because there are currently no programs which specifically target converting overhead to underground lines to address contact with energized equipment risks.

2. Drivers Impacted

Underground conversion was modeled as addressing all overhead drivers in this risk statement. This is based on a key underlying assumption – that the drivers considered in this chapter are by definition overhead drivers only. New risks would be introduced into the system with underground conversion. For example, people who are digging near underground electrical assets may expose themselves to "dig-in" risks of contact with energized underground cable. The new risks that would be introduced with underground conversion were not modeled in this analysis.

3. Outcomes and Consequences Impacted

Targeted Underground Conversion will not impact outcomes or consequences in the risk model.

D. M4 - Infrared Inspections

1. Description

Infrared (IR) Inspections for overhead distribution lines identify "Hot Spots" on distribution system equipment. Examples of equipment that will be included in these inspections are splices, connectors, switches, and transformers. Hot Spots are areas with temperature differences between either two phases, or two pieces of metal on one phase. Hot Spots are reliable predictors of future component failures that, if unaddressed, might lead to equipment failures. These Hot Spots are not visible to the naked eye and can only be detected by a trained thermographer using an IR camera.

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[38] *See* Rule 20 Replacement of Overhead with Underground Electric Facilities *available at* https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

This technology can be used proactively, in routine inspections, and assessments of facilities after a failure occurs to identify other potential conditions that may exist to further aid in preventing repeated circuit interruptions.

When infrared inspections identify problems that need to be mitigated, these problems would be addressed through SCE's Preventive Maintenance program (as previously described in CM3 above).

2. Drivers Impacted

Infrared inspections would only address Sub-Driver D1a (Connector / Splice / Wire). Infrared inspections are designed to be effective at identifying connectors, splices, wire, and other equipment that show signs of thermal fatigue. Infrared inspections are generally not effective at identifying other types of equipment failures or contact-related faults.

3. Outcomes and Consequences Impacted

Infrared Inspections will not impact outcomes or consequences in the risk model.

E. M5 – Wildfire Covered Conductor Program (WCCP)

1. Description

This mitigation represents the circuit miles in SCE's HFRA that SCE will target for reconductoring with covered conductor as a wildfire risk mitigation. WCCP identifies scope in three main categories: (1) spans with vintage small conductor at risk of damage during fault conditions, (2) spans with elevated risks of vegetation-related CFO faults, and (3) spans with elevated risks of non-vegetation-related CFO faults.

For purposes of the analysis described in this Chapter, SCE is only modeling this mitigation's impact on risks associated with Contact with Energized Equipment. The impact on risks associated with wildfire and WCCP details are described in the Wildfire Chapter.

2. Drivers Impacted

The WCCP (M5) impacts the same drivers addressed by the OCP (C1), namely: D1 (Equipment Cause), and D2 (Equipment/Facility Contact).[39] However, the WCCP assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the WCCP assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b, and D2d respectively).

[39] Specifically, C1a affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

3. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this mitigation was modeled as reducing the safety consequences associated with Outcome O1 (energized wire-down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor in an event involving Outcome O3 (Intact Energized Wire Contact). However, since O3 is such a small percentage of all of the modeled outcomes, SCE concluded that this effect would be negligible in the overall risk analysis. Therefore, as a simplifying assumption, SCE did not model any impact on the safety consequences associated with Outcome O3.

F. Advanced Wire-Down Detection

4. Description

In addition to the controls and mitigations listed above, SCE is working to develop advanced techniques to detect and clear high impedance faults, thereby reducing the probability that wire-down events will remain energized. Because the consequences of Outcome O1 (Energized Wire-Down) are much larger than the consequences of Outcome O2 (De-Energized Wire-Down), risk associated with contact with overhead conductor would be reduced with improvements in detecting wire-down. In the risk statement above, such mitigations would decrease the relative percentage of O1 and increase the relative percentage of O2.

The first technique under consideration is using meter data to detect wire-down events. This effort would apply an automated, rule-based detection algorithm to interval voltage data from SCE's meters to identify and alarm for observed low-voltage events in near real-time that could be indicative of wire-down events. A semi-automated version of this system, which automatically collects data but does not automatically take action based on that data, has been implemented by SCE as an initial demonstration project in 2018. Lessons learned from this demonstration project are being analyzed for future full-scale deployment.

The second technique under consideration is using high impedance fault detection modules within feeder protective relays. Protective relay manufacturers have been working to develop modules within feeder relays that have advanced algorithms to recognize the voltage or current signatures of high impedance faults, such as those that can occur with a wire-down feeder event. SCE previously installed relays with such modules on selected distribution feeders in 2016. At the time, these relays were configured to alarm – but not trip – for fault events that the relay algorithms determined to be possible wire-down events. Since 2016, numerous "nuisance alarms" (i.e., alarms without any corresponding wire-down event) have been identified. SCE has been working with relay manufacturers and other utilities to address this problem for future implementation.

The third technique under consideration is using Spread Spectrum Time-Domain Reflectometry (SSTDR) to detect wire-down events. This is a detection system that injects a high-frequency signal on the distribution circuit at a known starting point, and measures the returning signal reflections. These reflections are compared to a known "healthy" circuit profile and the location of anomalies – potentially indicative of high impedance faults – are reported by the system. SCE has very recently completed SSTDR prototype testing. We currently anticipate initiating an SSTDR field pilot in early 2019.

These mitigations were not modeled as part of this RAMP report, because the underlying techniques are not sufficiently mature at this time.

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Section III and has developed a Proposed Plan, as shown in Table V-1.

Table V-1 – Proposed Plan (2018-2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (OCP)	2018	2023	$ 715	$ -	3.22	0.0045	3.37	0.0047
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	2021	2023	$ 34	$ -	0.10	0.0029	0.10	0.0030
C2	Public Outreach	2018	2023	$ -	$ 33	0.42	0.0130	0.46	0.0140
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.04	0.3627	1.09	0.3797
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.55	0.0005
			Total - Proposed Plan	**$1,910**	**$36**	**5.32**	**0.0027**	**5.57**	**0.0029**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

The Proposed Plan includes the existing OCP at specified levels over the RAMP period. In this plan, the majority of OCP projects will be constructed with bare overhead conductor (C1), and a minority of projects will use covered conductor (C1a).

The Proposed Plan also includes Public Outreach (C2). This effort will focus on educating and informing the general public on what actions to take and to avoid when encountering a downed electrical wire. Our efforts here will also aim to inform at-risk workers such as third-party contractors, agricultural customers, and first responders regarding the dangers of working around energized equipment and downed wires. Additionally, the Proposed Plan includes infrared inspections of overhead equipment and connectors (M4) to identify problems and mitigate them before they result in faults and wire-down events.

The Proposed Plan also includes a specific mitigation identified in the Wildfire chapter (M5). This mitigation involves installing covered conductor within SCE's high fire risk area. While this mitigations is designed to address risks associated with wildfire, it is expected to provide *additional* risk reduction benefits related to contact with energized overhead conductor as well.

B. Execution feasibility

Executing the bare conductor OCP component (C1) is feasible as it relies on highly mature work processes, well-understood equipment types, and established work methods. SCE has a high degree of confidence in its ability to target, execute, and derive benefit from the OCP program when built with bare conductor.

Regarding the covered conductor OCP component (C1a), SCE anticipates that the lessons learned from deploying the Wildfire Covered Conductor Program in HFRA (M5) – including the associated construction and design standards, material specifications, work methods, and so on – will make targeted covered conductor installation as feasible to execute as bare conductor.

Executing public outreach (C2) is feasible, since it reflects continued execution of a control activity currently in place today.

The execution of the infrared inspections mitigation (M4) is feasible as this mitigation measure has already been successfully piloted and is being implemented today. For example, in years 2016 and 2017, SCE piloted the successful scan of approximately 11,200 overhead circuit miles in the service territory. In 2018, SCE has been working to scan all of the remaining overhead circuit miles not included in previous years. By year end 2018, SCE will have successfully demonstrated its ability to systematically scan the entirety of its overhead distribution system.

The execution feasibility of the Wildfire Covered Conductor Program (M5) is discussed in detail in the Wildfire chapter.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. However, to understand the underlying cost-effectiveness differences of the proposed plan relative to the alternative plans, the RSEs of individual controls and mitigations as shown in Table II-7 need to be examined.

1. Conductor (C1 and C1a)

The Proposed Plan involves the existing OCP with a majority of bare conductor (i.e., C1) and a targeted minority of covered conductor (i.e., C1a). This is fundamentally different than Alternative Plan #1, which assumes existing OCP with entirely covered conductor. This is also fundamentally different than Alternative Plan #2, which assumes a targeted minority of underground conversion (M3) instead of covered conductor.

Therefore, the alternative plans reflect two theoretical "enhancements" to the Proposed Plan: (1) In Alternative Plan #1, we deploy 100% instead of 10% of covered conductor expenditures; and (2) In Alternative Plan #2, we deploy 10% underground conversion instead of 10% covered conductor expenditures.

When we look at the collective RSEs of conductor-related controls and mitigations – i.e., C1 and C1a (Proposed Plan) versus M1 (Alternative Plan #1) versus C1 and M3 (Alternative Plan #2), the Proposed Plan reduces the most risk, addresses the most circuit miles, and has the most spend-efficient conductor mitigation combination all at the same time. These comparative details are shown in Table V-2 below.

Table V-2 – Comparison of Conductor-Related Mitigation Options

	Cost ($M)	MRR	RSE	Miles Addressed
C1 and C1a *(OCP + Targeted Covered Conductor)* *(Proposed Plan)*	749.5	3.32	4.430E-03	2,045 circuit miles
M1 *(OCP using Covered Conductor)* *(Alternative Plan #1)*	749.5	3.25	4.336E-03	1,749 circuit miles
C1 and M3 *(OCP + Underground Conversion)* *(Alternative Plan #2)*	790.1	3.31	4.189E-03	1,992 circuit miles

2. Public Outreach (C2) and Infrared Inspections (M4)

Public Outreach (C2) and Infrared Inspections (M4) are included in all three mitigation plans. Public Outreach is the one mitigation that directly addresses the human element of contact with overhead conductor, by helping to educate the public about the potential hazards of coming into contact with energized power lines. Infrared Inspections enable SCE to target degraded connectors, splices, and attachments nearing the end of their life. Both of these activities – M4 in particular – are relatively low-cost and high-RSE activities based on the modeling results.

3. Wildfire Covered Conductor Program (M5)

SCE has included the WCCP in the proposed and alternative plans for this chapter because they are in the Proposed Plan of the Wildfire chapter. As highlighted above, the WCCP is designed to address risks associated with wildfire, but it is also expected to provide additional risk reduction benefits related to contact with overhead conductor risks as well. Therefore, this mitigation is included in the Proposed Plan shown above.

Wildfire risk benefits of M5 were specifically excluded in this chapter, just as contact-with-overhead conductor risk benefits of M5 were excluded in the Wildfire chapter. This helps ensure that M5 benefits were not double-counted. However, SCE did include full M5 costs in the RSE calculations in both chapters, because SCE does not have a methodology for accurately dividing the cost of any program that provides benefits across multiple independent risk statements. In essence, RSE calculations for M5 assumed only *some* of the expected *benefits* (i.e., benefits specific to each chapter) but *all* of the expected *costs* (i.e., the full program cost in both chapters). The net effect of this is that calculated RSEs for the WCCP were understated in each of these two chapters.

D. Other Constraints

The Proposed Plan assumes that SCE will be able to identify OCP-candidate circuits that are most appropriate for covered-conductor targeting (C1a). SCE does not presently have scoping tenets that clearly define which non-high fire risk area circuits are most appropriate for covered conductor versus bare conductor when building OCP projects. SCE anticipates that the appropriate places for implementing covered conductor as part of OCP are locations with a combination of small-wire exposure and a clear history of repeated exposure to contact from object faults such as balloons, animals, and vegetation. SCE expects that the lessons learned from covered conductor in high fire risk areas (i.e., M5) will help inform the scoping tenets for targeted implementation of covered conductor in non-high fire risk areas (i.e., C1a).

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VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an Alternative Plan #1, as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018-2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C2	Public Outreach	2018	2023	$ -	$ 33	0.42	0.0129	0.46	0.0139
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	2018	2023	$ 750	$ -	3.25	0.0043	3.36	0.0045
M2	Comprehensive Branch Line Fusing	2018	2023	$ 83	$ -	0.29	0.0035	0.31	0.0037
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.09	0.3798	1.14	0.3973
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.55	0.0005
			Total - Alternative #1	**$1,994**	**$36**	**5.59**	**0.0028**	**5.81**	**0.0029**

A. Overview

There are two primary differences between Alternative Plan #1 and the Proposed Plan. First, Alternative Plan #1 assumes that all OCP projects will be constructed with covered conductor (M1) instead of a combination of bare conductor (C1) and targeted covered conductor (C1a). This alternative was selected to compare the risk mitigation benefits of an entirely-covered conductor standard for OCP against the primarily bare conductor standard for OCP that is currently in place today.

Second, Alternative Plan #1 implements Comprehensive Branch Line Fusing (M2), while the Proposed Plan does not. This was done to compare the differences between an accelerated Branch Line Fusing deployment strategy and the current Branch Line Fusing strategy achieved through the OCP. All other controls and mitigations are consistent between Alternative Plan #1 and the Proposed Plan.

B. Execution feasibility

Alternative Plan #1 is technically feasible to execute. We anticipate learning from the deployment of covered conductor in HFRA (M5) to help facilitate the deployment of M1. These lessons learned from deploying covered conductor in HFRA (M5), may involve the associated construction and design standards, material specifications, work methods, etc.

Alternative Plan #1 may not be feasible to implement from a process perspective. For purposes of this RAMP report, we model M1 as if it were deployed in 2018. However, we expect that lead times due to engineering, design, and material procurement would delay that deployment.

Regarding executing a comprehensive Branch Line Fusing program (M2), SCE has not previously implemented such a fuse installation program at this scale and pace. However, SCE has extensive experience installing BLFs at individual locations throughout its service territory. Executing such a program is assumed to be feasible as it would rely on highly mature work processes, well-understood equipment types, and established work methods.

For all other controls and mitigations, please see the execution feasibility discussion in the Proposed Plan section above.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. Below, we discuss the RSE differences between the Proposed Plan and Alternative Plan #1 in two areas: conductor and comprehensive branch line fusing.

1. Conductor (M1)

In terms of conductor-related mitigation options, Table V-2 above shows that Alternative Plan #1 reduces less risk, addresses less circuit miles, and is less spend-efficient than the Proposed Plan. These results indicate that fully deploying covered conductor as part of the OCP is not justified by risk analysis at this time.

2. Branch Line Fusing Mitigation (M2)

Alternative Plan #1 includes comprehensive Branch Line Fusing (M2) as a mitigation, whereas the Proposed Plan does not. The modeling results suggest that comprehensive Branch Line Fusing has a slightly lower RSE than the covered conductor mitigation modeled in M1.

SCE notes that short-term system-wide application of any mitigation – such as comprehensive Branch Line Fusing (M2) – will have a lower equivalent RSE than a more focused and targeted application on assets that represent the greatest risk at the present time. A short-term, comprehensive program would still be appropriate in situations where the residual risk after targeted benefit is not acceptable.

In this case, the modeling indicates that comprehensive Branch Line Fusing (M2), while efficient from a spending perspective, would reduce a relatively small amount of total risk. Specifically, the application of M2 would reduce the total baseline risk by approximately 1% in MARS units. While this mitigation is not in the Proposed Plan, SCE will continue to deploy branch line fuses within the OCP program, and will evaluate additional opportunities for targeted deployment.

D. Other Considerations

SCE is not aware of other issues associated with Alternative Plan #1.

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VII. Alternative Plan #2

SCE evaluated other options to address this risk, and developed an Alternative Plan as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018-2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	**Name**	**Start Date**	**End Date**	**Capital**	**O&M**	**MRR**	**RSE**	**MRR**	**RSE**
C1	Overhead Conductor Program (OCP)	2018	2023	$ 715	$ -	3.19	0.0045	3.34	0.0047
C2	Public Outreach	2018	2023	$ -	$ 33	0.43	0.0130	0.46	0.0140
M2	Comprehensive Branch Line Fusing	2018	2023	$ 83	$ -	0.29	0.0035	0.30	0.0036
M3	Targeted Underground Conversion	2021	2023	$ 75	$ -	0.12	0.0017	0.13	0.0017
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.03	0.3606	1.08	0.3771
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.54	0.0005
			Total - Alternative #2	**$2,034**	**$36**	**5.60**	**0.0027**	**5.86**	**0.0028**

A. Overview

There are two primary differences between Alternative Plan #2 and the Proposed Plan. Alternative Plan #2 assumes that the majority of OCP projects will be constructed with bare overhead conductor (C1), and a targeted minority of projects will use full underground conversion (M3) instead of targeted covered conductor. This alternative was selected to compare the differences between covered conductor and underground conversion for risk mitigation benefits.

Alternative Plan #2 also assumes the implementation of a comprehensive branch line fusing program (M2), while the Proposed Plan does not. This mitigation was selected to compare the differences between an accelerated fusing strategy and the current fusing strategy achieved through the OCP.

All other controls and mitigations are consistent between this alternative and the Proposed Mitigation Plan.

B. Execution feasibility

Alternative Plan #2 is feasible to execute for a variety of reasons. With respect to executing the targeted underground conversion OCP component (M3), SCE notes that the modeling of M3 has resulted in a relatively small number of circuit miles that would actually be converted to underground on an annual basis. SCE anticipates that the lessons learned from underground conversion projects under Rule 20 would make covered conductor installation feasible to execute. However, SCE also notes that M3 would be subject to additional delays associated with the greater complexities that can take place when constructing underground conversion projects.

For all other controls and mitigations included in this plan, please refer to the discussion above in the execution feasibility sections of the Proposed Plan and Alternative Plan #1.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. Below, we discuss the RSE differences between the Proposed Plan and Alternative Plan #2 in two areas: conductor and comprehensive branch line fusing.

1. Conductor (C1 and M3)

In terms of conductor-related mitigation options, Table V-2 above shows that Alternative Plan #2 reduces less risk, addresses less circuit miles, and is less spend-efficient than the Proposed Plan. These results indicate that underground conversion as part of the OCP is not justified by risk analysis at this time.

2. Branch Line Fusing Mitigation (M2)

For discussion of the comprehensive branch line fusing mitigation (M2), please see the discussion in Alternative Plan #1 above.

D. Other Considerations

SCE is not aware of other issues associated with Alternative Plan #2.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has learned some important lessons through this RAMP process in terms of interdependence assumptions in modeling the effectiveness of individual mitigations, degrees of confidence in modeling mitigation effectiveness, and similarity between scope and cost in mitigation portfolios.

1. Interdependence Assumptions in Mitigation Effectiveness Modeling

One of the challenges SCE faced in this RAMP chapter is that modeling mitigation effectiveness is much more challenging in a comprehensive mitigation portfolio than it is for individual mitigations. While this topic is especially relevant to this chapter, it also affects other RAMP chapters as well. Accordingly, we explain this lesson learned in greater detail in Chapter II – Risk Model Overview.

2. Degrees of Confidence in Mitigation Effectiveness Modeling

There can be a wide variety of degrees of confidence in modeling mitigation effectiveness. While the RAMP methodology does simulate risk uncertainty (through probabilistic analysis of consequence distributions), it does not, at present, have a way to describe underlying uncertainty in modeling mitigation effectiveness. While this topic is especially relevant to this chapter, it also affects other RAMP chapters as well. Accordingly, we explain this lessons learned in greater detail in Chapter II – Risk Model Overview.

3. Similarity between Scope and Cost in Mitigation Portfolios

Finally, SCE learned the importance of developing mitigation portfolios where there is a wide enough variation between scope and cost in the various mitigation portfolios. In this case, SCE used a cost-based approach to define portfolios. In other words, SCE held the OCP expenditures constant among all three portfolios (i.e., the dollars spent), and varied the amount of scope that could be constructed within that expenditures. This resulted in relatively small variations in benefits, and therefore very similar RSE results among the portfolios. To take just one example, the similarity between the 10% cost representation of C1a (covered conductor) in the Proposed Mitigation Plan and the 10% cost representation of M3 (targeted underground conversion) in Alternative Plan #2 made it very difficult to see variety in the modeling results.

In retrospect, greater clarity of the actual RSE differences would have been achieved had SCE modeled a wider range of scope and cost in the mitigation portfolios.

B. Data Collection & Availability

One of the biggest challenges that SCE faced in this RAMP modeling effort was understanding the distribution of outcomes between Energized Wire-Down (O1) and De-Energized Wire-Down (O2). In SCE's Wire-Down Database, approximately half of the wire-down events are listed as either "unknown" or "blank" with respect to whether the conductor was energized on the ground. SCE attributes this to the fact that the Wire-Down Database is populated by personnel who arrive on the scene sometime after the wire-down event takes place. Typically, there is limited information at their disposal to understand the precise sequence of events and determine definitively whether the wire on the ground was energized or not at the time of the event. This was a challenge for RAMP modeling purposes.

SCE modeled the distribution of outcomes O1 and O2 based on assuming that the unknowns represent a mix of both energized and de-energized wire-down events. Going forward, SCE anticipates that continued development of more advanced high impedance fault detection techniques will help bridge this gap and further refine the actual distribution of outcomes O1 and O2 in the system. For additional details, see the "Advanced Wire-Down Detection" discussion in the Mitigations section above.

C. Performance Metrics

SCE has identified three performance metrics that are attributable to this risk including:

- Number of CPUC-reportable safety incidents associated with overhead conductor.
- Number of wire-down events.
- Outage minutes due to wire-down events.

Additionally, SCE has identified useful metrics to track effectiveness in executing programs. These metrics involve tracking the number of deployed unit counts versus planned unit counts related to our overhead conductor, including:

- Circuit miles of OCP projects constructed.
- Number of Branch Line Fuses installed as part of OCP.
- Circuit miles of covered conductor installed.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Cyberattack

Chapter 6

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

In this chapter, we evaluate the risk to SCE, our electric system, and the customers and communities we serve if a cyberattack compromises SCE system controls. SCE identified and quantified the potential safety, reliability, and financial consequences resulting from this risk.

SCE's bowtie structure for this cyberattack risk has identified several options to mitigate the risk. We present a Proposed Plan that balances risk mitigation, execution feasibility, and cost efficiency. SCE's proposed portfolio of mitigations leverages the success of existing and ongoing cybersecurity programs, and adds enhanced capabilities that will help maintain our defenses amidst the growing and persistent threat of cyberattack.

Cybersecurity presents an ever-evolving challenge to SCE. The threat of cyberattacks is growing; attacks are continually becoming more frequent and more sophisticated. Our grid is evolving and incorporating communicating and operating technology that enable us to respond faster, operate our system more efficiently and reliably, and incorporate distributed energy resources at a greater level. But more reliance on advanced technology to operate and communicate necessarily increases risk of cyberattack, and greater potential consequences if a cyberattack is successful. State and federal government agencies are increasingly supporting cybersecurity. That support springs from the growth in cyberattack risks. SCE will need to increase its capabilities to address this.

B. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 - Chapter Scope	
In Scope	• Unauthorized access to SCE's system controls, including our Supervisory Control and Data Acquisition (SCADA) network, industrial control systems (ICS), and other systems that access and utilize Critical Energy/Electric Infrastructure Information (CEII).[1]
Out of Scope	• Risks associated with protecting non-grid related cybersecurity concerns, such as Personally Identifiable Information (PII), operations related to billing and payment, customer care, etc. These are out of scope because the probable and direct safety consequences range from zero to very little. However, if such non-grid related cybersecurity areas can be utilized as a pathway to our grid network, then we address these areas as appropriate in this chapter.[2] • Secondary, indirect safety risks associated with cyberattacks.[3]

C. Summary Results

Table I-2 summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.

[1] These are the systems that operate the electric system today, from central-station power plants, to our transmission and distribution power systems, and reaching through to the interconnection of utility-scale and localized, distributed energy resources.

[2] While not the focus of this RAMP chapter, SCE maintains robust data controls to protect the privacy of our five million customers, and secure the vendor data in our possession.

[3] For example, the potential secondary safety impacts that result if our control systems are comprised and the end result is a persistent blackout. SCE believes this is a viable and adversary-desired outcome that could potentially lead to significant safety and financial consequences. However, at this time, the modeling of such a scenario involves developing considerable assumptions and a virtual cascade of hypothetical events, and is out of scope for this immediate RAMP analysis.

Table I-2 – Summary Results – 2018-2023 Annual Averages

Inventory of Controls & Mitigations			Mitigation Plan	
ID	Name	Proposed	Alternative #1	Alternative #2
C1a	Perimeter Defense	x		
C1b	Perimeter Defense		x	
C1c	Perimeter Defense			x
C2a	Interior Defense	x		
C2b	Interior Defense		x	
C2c	Interior Defense			x
C3a	Data Protection	x		
C3b	Data Protection		x	
C3c	Data Protection			x
C4a	SCADA Cybersecurity	x		
C4b	SCADA Cybersecurity		x	
C4c	SCADA Cybersecurity			x
C5a	Grid Modernization Cybersecurity	x		
C5b	Grid Modernization Cybersecurity		x	
C5c	Grid Modernization Cybersecurity			x
M1	Accelerated Hardware Refresh			x
Mean (MARS)	*Cost Forecast ($ Million)*	$80	$77	$92
	Baseline Risk	1.78	1.78	1.78
	Risk Reduction (MRR)	0.72	0.37	0.99
	Remaining Risk	1.06	1.42	0.79
	Risk Spend Efficiency (RSE)	0.009	0.005	0.011
Tail Average (MARS)	*Cost Forecast ($ Million)*	$80	$77	$92
	Baseline Risk	11.02	11.02	11.02
	Risk Reduction (MRR)	4.56	2.29	6.34
	Remaining Risk	6.47	8.74	4.68
	Risk Spend Efficiency (RSE)	0.057	0.030	0.069

CM: Compliance (Not shown in this chart, but addressed in Section III; this is an activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this report, and as such, excludes these activities from this table.)

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does model controls in this report.)

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE does model mitigations in this report.)

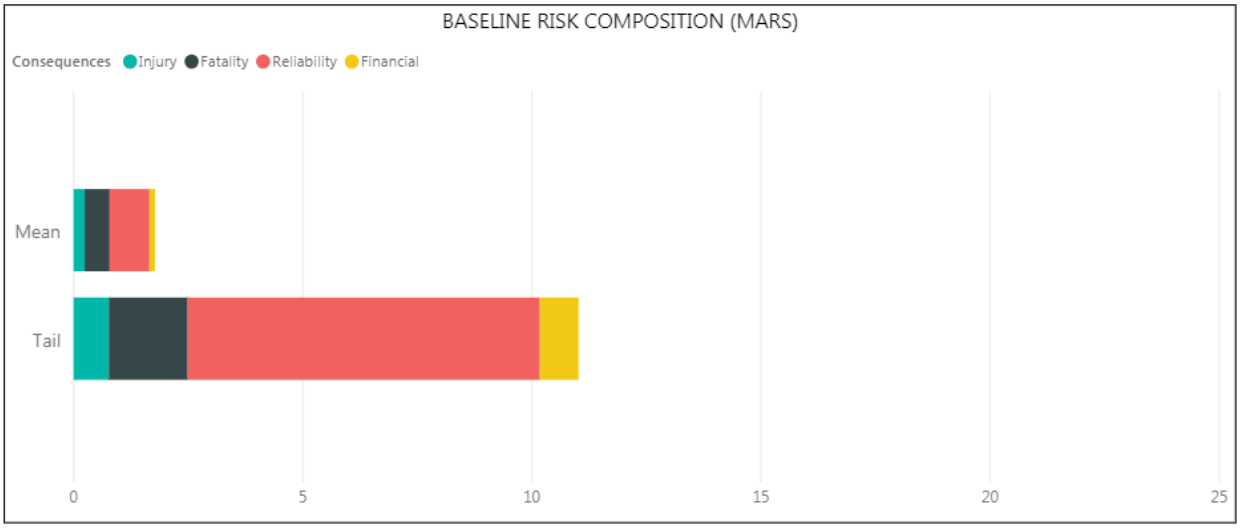
MARS: Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk consequences from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR: Mitigation Risk Reduction. This is the reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE: Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 maps the consequences inherent in the baseline risk. The majority of this risk is composed of reliability impacts.

Figure I-1 – Baseline Risk Composition (MARS)



MARS CONSEQUENCE

AggregationType	Injury	Fatality	Reliability	Financial	**Total**
Mean	0.24	0.55	0.87	0.12	**1.78**
Tail	0.77	1.72	7.69	0.84	**11.02**

Maximum MARS is 100

D. Sensitive, Confidential Information Must Be Protected

The RAMP process required that SCE perform detailed and confidential[4] internal evaluations of our computing and operating systems, cybersecurity tools, and areas of vulnerability. This was a very valuable process, and SCE appreciates the opportunity to critically evaluate our cybersecurity program as it continually evolves. The detailed analysis that we performed internally around cybersecurity has informed the discussion we present in this chapter. However, SCE must necessarily safeguard this critical information. SCE's cybersecurity efforts include protecting the electric grid, which has been designated by the Department of Homeland

[4] These evaluations required analyzing specific details concerning how various cyber defenses (such as software tools) perform in addressing different threats. Disclosing this information could potentially help an attacker gain crucial information about how SCE protects its systems, and where gaps might exist.

Security (DHS) as critical infrastructure.[5] Therefore, a secure process for disclosing detailed tactics, techniques, and procedures to stakeholders to this proceeding is needed to help ensure its protection.

To help the Commission access the information necessary to answer specific questions regarding the cybersecurity risks, mitigations, and cost forecasts, SCE can provide an in-person briefing to share additional detail not found in this Report.

[5] DHS identifies 16 critical infrastructure sectors whose assets, systems, and networks, whether physical or virtual, are considered so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof. The U.S. Energy Sector is defined as one of these Critical Infrastructure sectors. This information is *available at* https://www.dhs.gov/critical-infrastructure-sectors

II. Risk Assessment

A. Background

1. Increased Threat of Cyberattack

The energy sector is under continuous cyberattack.[6] The attack methods, strategies, and capabilities are constantly evolving as new types of attacks are discovered and carried out. Intrusion attempts against SCE continue to increase. Such attacks include computer viruses, worms, phishing, spyware, and advanced persistent threats. Any of these aggressive actions, if successful, could significantly damage SCE's information systems. A prominent security-related periodical has noted: "The modern enterprise network has become expansive, porous, and completely blurred due to the large number of Internet-facing applications that have been deployed and adopted. The number of potential entry points into the enterprise network has proliferated uncontrollably."[7]

Cybersecurity's importance to utilities has expanded as systems and data have become more integral to business operations, and as the electric infrastructure has become more essential to national commerce and communications capabilities. Cyberattacks are continually growing in number and sophistication, and the availability of cyber weapons[8] is on the rise as well. Therefore, maintaining a strong defense against cyberattack requires a continually evolving set of strategies.

2. Real-Life Examples of Costly Cyberattacks

Recent examples of cyberattacks are well-documented in the news media and the intelligence community. These include but are not limited to:

- The disruption of Ukraine's power grid by Russian cyber actors[9] in December 2015, causing over 225,000 customers to lose power.[10]
- The Federal Bureau of Investigation (FBI) and U.S. Department of Homeland Security (DHS) have identified that since at least March 2016, Russian government cyber actors targeted U.S. government entities and multiple U.S.

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[6] Please refer to SCE's Test Year 2018 General Rate Case, A.16-09-001, Exhibit SCE-04, Volume 2, Workpapers Book A, pp. 115-116.
[7] Refer to A.16-09-001, Exhibit SCE-04, Volume 2, Workpapers Book A, pp. 117-120.
[8] For example, BlackEnergy malware was initially used to steal banking credentials, but later re-designed to attack the Ukraine power utilities in 2015. BlackEnergy summary *available at* https://attack.mitre.org/wiki/Software/S0089
[9] Attacks were conducted from computers with IP addresses allocated to the Russian Federation.
[10] More information on the 2015 Ukraine cyberattack is *available at* https://www.wired.com/2016/01/everything-we-know-about-ukraines-power-plant-hack/

critical infrastructure sectors. This included the energy, nuclear, water, and aviation sectors.[11]

3. Cyberattackers Targeting Electric Utilities

The cybersecurity risks facing SCE's ICS/SCADA systems continue to grow in quantity and complexity. Since 2009, reporting organizations have experienced an average annual increase of 124% for ICS/SCADA cybersecurity incidents, based on figures published by the Department of Homeland Security Industrial Control Systems Computer Emergency Response Team (DHS ICS-CERT). As the number of these attacks increases, attackers are also leveraging more advanced tactics specifically designed to exploit ICS/SCADA systems. Electric utilities, including SCE, are heavily targeted by adversaries that use cyberattacks to degrade capabilities.

Attacks on SCADA and ICS are garnering national attention. For example, in 2017, Robert Lee from the Dragos Corporation released information and testified before Congress about cybersecurity attacks on industrial targets within the United States from foreign nation-states.[12] In the last three years, the attacks have become more technically proficient, demonstrating advances in adversarial skills and tactics against industrial corporations and entities. If a large-scale cyberattack against a U.S. electric utility occurs, it may spur new legislation and regulatory requirements over and above what is currently in place with NERC CIP regulations.

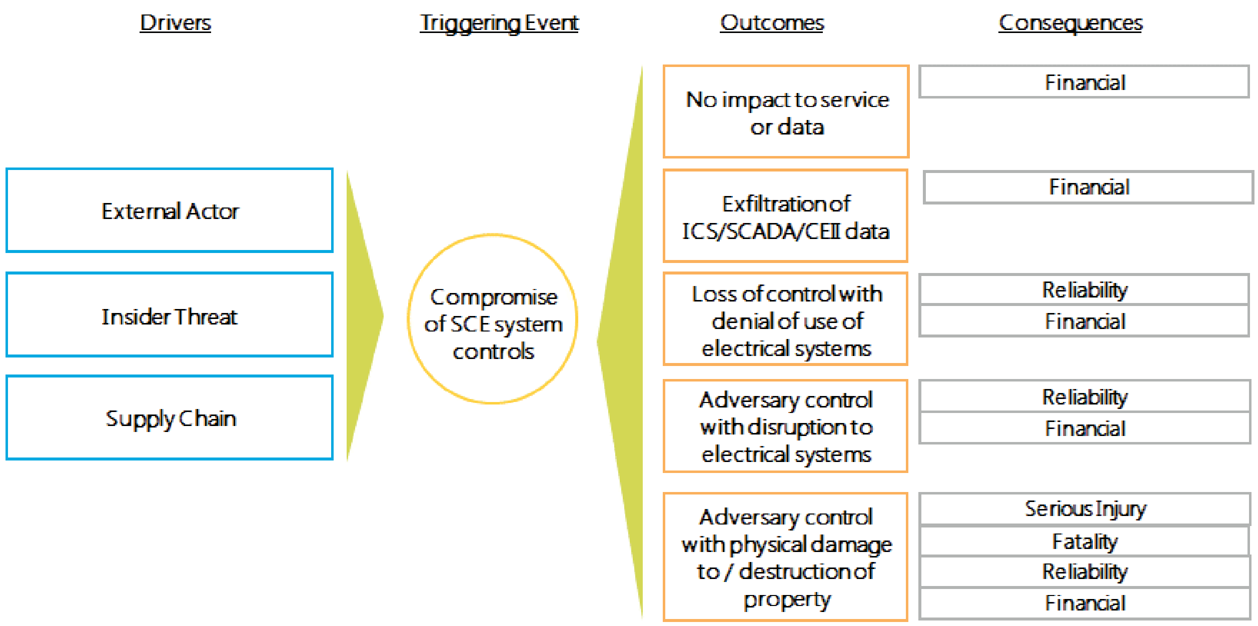
Just like utilities across the countries that are seeking to protect, detect, and respond to this growing threat, SCE has been prudently enhancing its cyber capabilities. We plan to maintain these defense capabilities over the RAMP period and beyond.

B. Risk Bowtie

To define and evaluate the risk of cyberattack within SCE's environment, SCE has constructed a cyberattack risk bowtie, as shown in Figure II-1 below. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

[11] United States Computer Emergency Readiness Team (US-CERT), *available at* https://www.us-cert.gov/ncas/alerts/TA18-074A.
[12] Robert Lee's testimony at the hearing is *available at* https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=5F40E0A2-B836-40EA-ACC6-9BF3B43A1B8F

Figure II-1 – Cyberattack Risk Bowtie



C. Drivers

SCE identified three primary drivers that lead to SCE control systems being compromised: External Actor, Supply Chain, and Insider Threat. These drivers are detailed below. Figure II-2 shows the projected 2018 frequency counts for each of these drivers.[13]

Figure II-2 – 2018 Driver Frequency

Name	Freq	Frequency
D1 - External Actor	6	
D2 - Insider Threat	1	
D3 - Supply Chain	0	

1. D1 – External Actor

An external actor is defined as any outside entity (a person, organization, nation-state, etc.) that attempts to maliciously bypass SCE's cybersecurity controls. Depending on the actor, potential motives for this action can include:

- Gaining access to SCE's grid network;
- Disrupting service or supporting business operations;

[13] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on these drivers.

- Exfiltrating sensitive SCE or customer data;
- Achieving financial gain or extortion;
- Creating competitive advantage; or
- Inducing sabotage, terror, or harm.

2. D2 – Insider Threat

An insider threat is defined as an actor within SCE, such as an employee or contractor, who knowingly bypasses SCE cybersecurity controls with malicious intent. Potential motives for insider threat attacks generally include:

- Gaining access to SCE's grid network;
- Causing loss of control of operating assets;
- Obtaining a competitive advantage;
- Intending to harm SCE due to adverse prior experiences with SCE; and
- Stealing proprietary or sensitive information that can be sold or brokered in underground marketplaces.

3. D3 – Supply Chain

Potential attacks on the supply chain represent an emerging threat for SCE, and more broadly the electric utility industry. An attack through SCE's supply chain, whether targeted or untargeted, could occur as follows:

- Compromising SCE-procured goods with embedded malware or other malicious code. Once such malware or code is on SCE's network, it can disrupt service, leak sensitive data, or harm system controls.
- Attacking a third-party organization in SCE's supply chain, including vendors and business partners. Once the attack occurs, it can be exploited to violate the trust relationships between SCE and its partners.

4. Developing Driver Data[14]

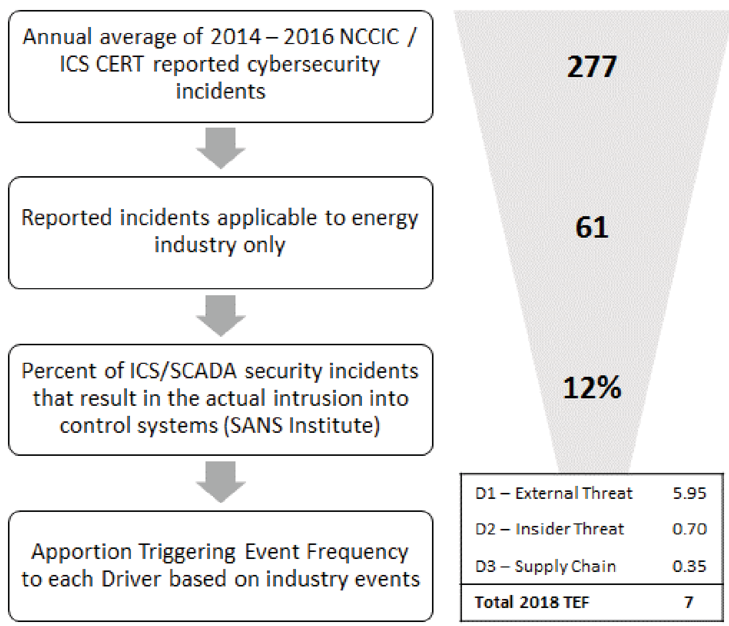
SCE identified the drivers that will continue to be the greatest threats to our operations. We evaluated these drivers using industry data. The availability of such industry data is necessarily limited. Similar to SCE, most utilities and companies that employ SCADA/ICS technologies are reluctant to disclose information or vulnerabilities, because such sharing this information may put their systems at greater risk of future attack. As such, where data was not

[14] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for more detail on the data and calculations used to develop driver data.

publicly available, we augment our analysis based on our relationships with several federal government defense agencies and industry experts.[15]

Figure II-3 summarizes how SCE determined triggering event frequency (TEF) and driver frequency for this RAMP analysis. A more detailed explanation follows the Figure.

Figure II-3 – Process Used to Develop 2018 TEF & Driver Data



SCE obtained the number of reported critical infrastructure incidents from the National Coordinating Center for Communications Integration Center (NCCIC) and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) Annual Review Reports.[16] These organizations operate under the direction of the Department of Homeland Security (DHS). SCE then filtered this data for incidents within the Energy Sector. This data showed that the average annual reported incidents across the country for 2014-2016 was 277; with 61 of those coming from the energy industry.

[15] Please refer to WP Ch. 6, pp. 6.5 – 6.6 *(Subject Matter Expert Qualifications)* for additional detail on these experts.

[16] The ICS-CERT annual reports can are *available at* https://ics-cert.us-cert.gov/Other-Reports

SCE then used data from these reports, as well as information substantiated through the SANS - Securing Industrial Control Systems 2017 Report,[17] to determine that approximately 12% of ICS/SCADA security incidents result in actual intrusion into control systems.

SCE then sourced these control system intrusions to each of the three drivers. SCE has found that in many cases, available industry reports[18] vary in interpreting the source of the cyberattack incidents. Therefore, SCE supplemented our review of these reports with the experience of an industry consulting firm, to estimate the incident source (by driver) for 2018.

Finally, SCE applied growth rates[19] to each driver to account for the increase in volume of cyberattacks that were experienced over the 2011-2016 period, and the growth we estimate would occur if our proposed cyber defenses were not fully deployed. Table II-1 shows the projected growth of each driver over the RAMP period.

Table II-1 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	**Total**
Cyber Attack							
Baseline	**7.00**	**7.86**	**8.82**	**9.93**	**11.19**	**12.62**	**57.42**
Driver							
D1 - External Actor	5.95	6.74	7.62	8.63	9.77	11.06	**49.77**
D2 - Insider Threat	0.70	0.70	0.70	0.70	0.70	0.70	**4.20**
D3 - Supply Chain	0.35	0.42	0.50	0.60	0.72	0.86	**3.45**

D. Triggering Event

In the context of this risk assessment, the triggering event is defined as a "Compromise of SCE system controls." This results when a technological control fails, causing the loss of control, operability, or visibility of a process in a manner that impacts SCE operations. System controls are defined as grid components that interact with protection, switching, and distribution systems either on the grid or in an internal network. These can be firewalls, endpoint security

[17] This report is *available at* https://www.sans.org/reading-room/whitepapers/analyst/securing-industrial-control-systems-2017-37860

[18] For example: Idaho National Laboratory. Cyber Threat and Vulnerability Analysis of the U.S. Electric Sector, *available at* https://www.energy.gov/sites/prod/files/2017/01/f34/Cyber%20Threat%20and%20Vulnerability%20Analysis%20of%20the%20U.S.%20Electric%20Sector.pdf

[19] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on these drivers growth rates.

software, network traffic inspection, Intelligent Electronic Device (IED), Remote Terminal Unit (RTU), Human Machine Interface (HMI), and similar technology.

E. Outcomes & Consequences

SCE identified a range of outcomes that would occur if our control systems were compromised. In developing these outcomes, we took into account evolving cyber threats and specific aspects of our grid infrastructure and operations. SCE estimated the expected likelihood of each outcome occurring, should the triggering event occur. This effort yielded the following outcome likelihoods as shown in Figure II-4:

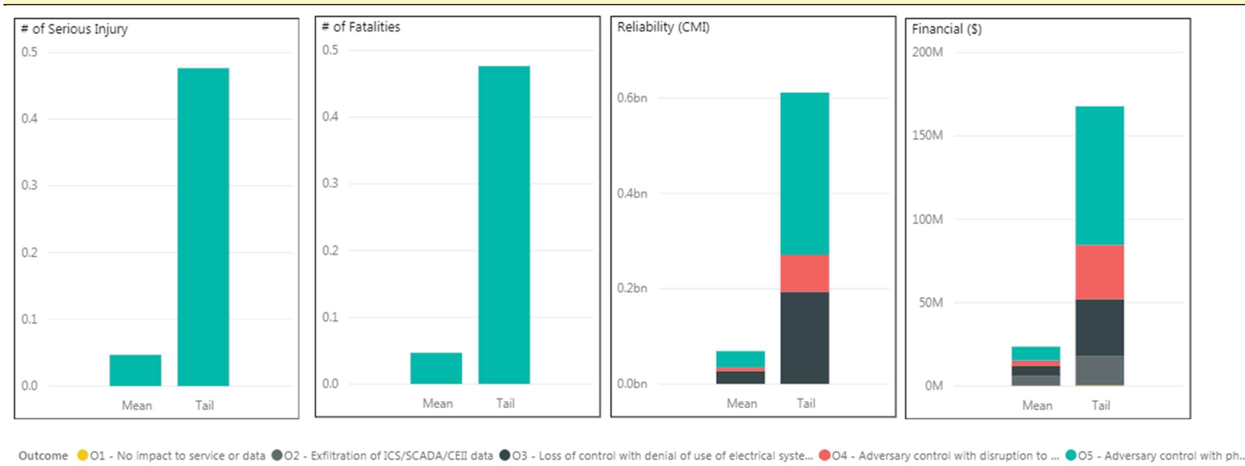
Figure II-4 – 2018 Outcome Likelihood

Outcome Percentage

Name	%	Percent
O1 - No impact to service or data	84.0 %	
O2 - Exfiltration of ICS/SCADA/CEII data	11.0 %	
O3 - Loss of control with denial of use of electrical systems	3.5 %	
O4 - Adversary control with disruption to electrical systems	1.0 %	
O5 - Adversary control with physical damage to /destruction of electrical system	0.5 %	

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence dimension. This shows that all of the safety consequences of this risk would be effectuated through O5 (Adversary control with physical damage to, or destruction of, the electrical system). In addition, the majority of the reliability and financial consequences originate from three outcomes: O3 (Loss of control with denial of use to electrical systems), O4 (Adversary control with disruption to electrical systems), and O5 (Adversary control with physical damage to, or destruction of, the electrical system). The sections that follow detail the inputs we used to arrive at these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (NU)



1. O1 – No impact to service or data

In this outcome, an attacker can breach our industrial control centers, yet do nothing. Anomalous activity, such as evidence of past intrusions or malware containment, does not directly affect SCE's ability to safely and reliably deliver power to its customers, although it can result in remediation costs. Remediation can involve external cybersecurity resources to determine if a more involved compromise occurred.

To take a real-life example, a small flood control dam[20] (Bowman Dam) in Port Chester, New York was targeted by Iranian adversaries, and its systems were exploited as part of a larger cyberattack against financial institutions. The compromised systems could have been used to cause flooding in the immediate surroundings. However, the sluice gate controls connected to the internal systems were deactivated at the time due to maintenance and repair. Therefore, there was no actual impact to safety or reliability. However, there were costs to remediate and patch the plant's IT systems.

Table II-2 shows the model input data and sources used, and the resulting annualized consequence impacts on a mean and tail-average basis. For example, based on the input data described in the table, the RAMP model provides annualized estimates of the actual consequences that would be incurred if this risk were left unmitigated. For O1, this translates to an annualized impact of approximately $212,000 in financial harm on a mean basis, or approximately $376,000 on a tail-average basis.

Table II-2 – Outcome 1 (No Impact to Service or Data): Consequence Details[21]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				SCE models this outcome by using an average cost per cybersecurity incident of $52,600. This divides the average annualized cost for cybercrime at utilities and energy sector companies ($17.2M as determined by Ponemon Institute & Accenture) by the number of projected incidents in 2017 (327, based on trend analysis from ICS-CERT reports).
Model Outputs	Mean				$211,518
	Tail-Average				$375,928

[20] *See* Joseph Berger, *A Dam, Small and Unsung, Is Caught Up in an Iranian hacking Case* (March 26, 2016) *available at* https://www.nytimes.com/2016/03/26/nyregion/rye-brook-dam-caught-in-computer-hacking-case.html

[21] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O1.

2. O2 – Exfiltration of ICS/SCADA/CEII data

In this outcome, an attacker obtains SCADA, ICS, or other CEII data from SCE's network. This can provide adversaries with advanced levels of knowledge on how our grid is designed and operated. This knowledge can be used to target specific operating units within the company and compromise their systems. When compromised, the target systems can be rendered inoperable. Then we must manually operate the systems (if it's even possible to do so) to maintain operability.

Table II-3 shows the model input data and sources used, and the resulting annualized consequence impacts on a mean and tail-average basis for this outcome. This translates to an annualized impact of approximately $5.8 million in financial harm on a mean basis, or approximately $17.8 million on a tail-average basis.

Table II-3 – Outcome 2 (Exfiltration of ICS/SCADA/CEII Data): Consequences Details[22]

Outcome 2		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*				According to a report by the Ponemon Institute and a related Data Risk Calculator from IBM, the cost for a data breach in the Energy Industry ranges from $3.4 million to $7.4 million depending on the number of compensating controls in-place for the specific energy utility. These costs include direct expenses such as hardware, software, and services remediation costs, hiring external data forensics and cybersecurity experts to determine the scope of breach and data compromised, and indirect expenses related to internal investigations and additional audit and assessment activity surrounding the breach.
Model Outputs	Mean				$5,796,828
	Tail-Average				$17,772,110

3. O3 – Loss of control with denial of use of electrical systems

Loss of electrical systems control due to denial of use has the potential to result in short-term effects, including:

- Disabling the connectivity between SCE transmission and distribution sites, requiring manned support for locations which are typically unmanned. This causes increased spending for overtime and less efficient manual transfers of connections.

[22] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O2.

- Disabling remote grid management functions. Then, our personnel must travel to the physical site locations to support restoring operations for affected components.

In an industrial environment, loss of control has a varied impact, which can range from lessened Overall Equipment Effectiveness (OEE) all the way up to complete process failure of generation, transmission, and distribution functions, and a resulting shutdown of operations.

Across the world, multiple cyberattacks in 2017 were attributed to malware which spread rapidly within companies and caused operational outages in transportation and manufacturing. This caused production failures by pharmaceutical company Merck[23] and transportation impacts for transportation company Maersk.[24] Denial of use attacks can potentially result in short-to-medium-term outages within SCE's territory.

Table II-4 – Outcome 3 (Loss of Control with Denial of Use to Electrical Systems): Consequences Details[25,26]

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			The 2015 Ukrenergo power distribution system cyberattack resulted in approximately 6 hours of electrical outage to 225,000 customers, or 81 million customer minutes of interruption.	SCE estimated the cost to recover and/or replace the IT hardware and software systems that would likely be affected after an attack of this magnitude.
Model Outputs	Mean			27,279,257	$6,091,732
	Tail-Average			194,493,969	$34,113,815

4. O4 – Adversary control with disruption to electrical systems

Adversary control that disrupts electrical systems occurs when an adversary successfully penetrates our systems and can execute controls in the same manner as SCE

[23] *See* Patrick Howell O'Neill *, Cyberscoop* article (October 27, 2017) *available at* https://www.cyberscoop.com/notpetya-ransomware-cost-merck-310-million/

[24] *See* Lee Mathews *NotPetya Ransomware Attack Cost Shipping Giant Maersk Over $200 Million* article (August 16, 2017), *available at* https://www.forbes.com/sites/leemathews/2017/08/16/notpetya-ransomware-attack-cost-shipping-giant-maersk-over-200-million/#4a518b794f9a

[25] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O3.

[26] There are obvious differences in the size and structure of SCE's and Ukrenergo's respective distribution systems. However, there are enough similarities between the two grids, in terms of equipment and devices used to control and operate the grid, that comparison is warranted. The Ukrenergo attackers compromised Remote Terminal Units (RTU) and digital relays to control the electrical system. SCE uses this same technology (from different vendors) in the grid network.

operators. This allows an attacker to control the flow of power, perform switching operations, and undertake other, similar actions. Such actions can prevent an electric utility from safely managing electric system operations, and can cause outages or periods of unstable power delivery to customers. When inputs, such as fuel or byproducts are involved, there is also the possibility of an unintended release of substances that could cause environmental consequences or harm to persons or property.

For example, in 2015 the Ukrenergo power company in Kiev, Ukraine was attacked by a nation-state adversary. This adversary utilized multiple cyberattack paths, including the network (spear phishing and BlackEnergy malware data collection), and telephone (Denial of Service aimed at the call center, thereby denying consumer data and impairing communications between facilities). The adversary was able to manipulate key functions of the SCADA and substation switching processes, causing power loss to approximately 225,000 customers.

Adversary control of our electric system could potentially result in short-to-medium-term outages within SCE's territory. SCE would also incur financial consequences associated with recovering and/or replacing the IT hardware and software systems that would likely be damaged after an attack of this magnitude. In addition, such an event would require a comprehensive forensic analysis, adversary eviction, and rapid mitigations to prevent similar incidents.

Table II-5 – Outcome 4 (Adversary Control with Disruption to Electrical Systems): Consequences Details[27]

Outcome 4		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			The 2015 Ukrenergo power distribution system cyberattack resulted in approximately 6 hours of electrical outage to 225,000 customers, or 81 million customer minutes of interruption.	SCE estimated the cost to recover and/or replace the IT hardware and software systems that would likely be affected after an attack of this magnitude.
Model Outputs	Mean			7,799,644	$3,303,492
	Tail-Average			77,776,571	$32,748,983

[27] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O4. Also note, the relative magnitude of consequences in Outcome 4 may be less than Outcome 3 due to the much lower likelihood of Outcome 4 (1.0%) occurring than Outcome 3 (3.5%).

5. **O5** – Adversary control with physical damage to, or destruction of, the electrical system

This outcome represents a reasonable worst-case scenario where an adversary successfully penetrates our cyber defenses, assumes control of our grid control system, and executes actions which damage or destroy portions of SCE's electric system or other property. Utilizing publicly available data, SCE could not find a reported instance of direct injury to a person or loss of life resulting from a cyber-related incident in the utility industry. However, SCE reasonably believes that such an attack is possible now or in the near future, and that adversarial entities are continually evaluating such possibilities.

As such, SCE evaluated scenarios where this outcome might occur on SCE's system. Due to prior vulnerabilities exposed by cyberattacks at hydroelectric facilities (Bowman Dam, for example), SCE evaluated the impact of a cyberattack on our hydroelectric generation system. SCE examined the potential impacts of a breach of our control systems which could potentially trigger the uncontrolled and rapid release of water and potentially lead to safety, reliability, and financial consequences. Beyond safety and reliability impacts, the potential costs resulting from this outcome would include capital spending to rebuild any damaged or destroyed hydroelectric equipment, as well as damage to other property located downstream of the event. This could include costs to rebuild roadways, bridges, and other facilities that could be impaired or destroyed by an uncontrolled release of water. In addition, SCE would have to repair and/or replace the SCADA/ICS infrastructure that was affected by the attack.

In addition, SCE evaluated the impacts of a potential coordinated cyberattack on multiple substations within our service territory. This scenario contemplates the financial and reliability impacts from an attack on three substations, similar to the attack contemplated within the Physical Security chapter.

Table II-6 – Outcome 5 (Adversary Control with Physical Damage to, or Destruction of, the Electrical System): Consequence Details[28]

Outcome 5		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE evaluated two potential cyber attack scenarios where an adversary obtains control of our grid assets and causes physical damage to, or destruction of, the electrical system. These scenarios include an attack on our hydroelectric system, as well as a coordinated attack on multiple substations.			
Model Outputs	Mean	0.05	0.05	34,250,455	$8,359,169
	Tail-Average	0.48	0.48	342,504,554	$83,591,685

[28] SCE's cybersecurity efforts are focused on protecting critical infrastructure. Therefore, a secure process for disclosing detailed tactics, techniques, and procedures is necessary to help ensure continued security and protection. As indicated above, if the Commission needs access to the information to answer specific questions regarding the cybersecurity risk, mitigations, and cost forecasts, SCE can provide an in-person briefing in a closed setting to provide more information.

III. Compliance & Controls

As cybersecurity threats significantly increase in volume and complexity year-over-year, SCE must continually adapt its defense strategies. SCE employs a defense-in-depth cybersecurity strategy. This strategy utilizes multiple layers of protection, and proactive vulnerability testing, to prevent unauthorized access and control of SCE's systems.

SCE organizes its cybersecurity defense into six program areas: Perimeter Defense, Interior Defense, Data Protection, SCADA Cybersecurity, Grid Modernization Cybersecurity, and North American Electric Reliability Corporation - Critical Infrastructure Protection (NERC CIP) Compliance. Each of these controls represents a risk reduction strategy to this cyberattack RAMP risk, and is described in more detail below.

Table III-1 summarizes the impact of each cybersecurity program mitigation on the drivers and outcomes identified in the cyberattack bowtie. This table presents a mapping of controls to those drivers and outcomes that are most heavily impacted by each mitigation. Each of these controls is composed of a number of projects and initiatives; however, due to the confidential nature of these efforts, we do not disclose or discuss each of these efforts individually.

Table III-1 – Inventory of Compliance & Controls[29]

Inventory of Controls		Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
ID	Name				Capital	O&M
CM1	NERC CIP Compliance	Not Modeled	Not Modeled	Not Modeled	$ 0.1	$ 12.8
C0	Common Cybersecurity Solutions	Not Modeled	Not Modeled	Not Modeled	$ 0.2	
C1	Perimeter Defense	D1, D2	All	All	$ 18.2	
C2	Interior Defense	D2, D3	All	All	$ 10.1	
C3	Data Protection	All	O2	F	$ 10.4	
C4	SCADA Cybersecurity	All	O3, O4, O5	All	$ 10.6	
C5	Grid Modernization Cybersecurity	All	O3, O4, O5	All	$ 15.0	

CM: Compliance (Activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this RAMP report.)
C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE risk-models control in the RAMP report.)
Consequence Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial - F

[29] Please note that in this table, SCE maps how each control impacts drivers, outcomes, and consequences. For purposes of modeling in the RAMP report, SCE only adjusts outcome probabilities over time. Also, SCE has historically tracked O&M at a portfolio level, and not by each control.

A. CM1 – NERC CIP Compliance

NERC CIP Compliance is an existing compliance control. This program continues the ongoing implementation of systems and processes that help SCE comply with the evolving cybersecurity-related NERC CIP requirements. These systems and processes will improve how we manage facility access, maintain asset change control, and control physical access.

B. C0 – Common Cybersecurity Solutions (CCS) for Generator Interconnections

This control was implemented from 2012 – 2017. Each device on the electric grid secured by CCS will have a unique key to enable secure communications with its control system. This approach mitigates the risk that an attacker can seize control of the electric grid from an individual device, such as a relay or capacitor bank controller. It also lets SCE rapidly identify and respond to a cybersecurity event.

The CCS project also enhances cybersecurity protections for critical generator interconnections. The applications on these interconnection paths require low latency[30] to transmit data to back-office systems. We must retain control of the communications, because these systems make automated control decisions on the electric grid. The CCS system is specially designed to provide cybersecurity protection over the communication paths, while maintaining the performance requirements to enable capabilities of low latency control systems.

C. C1 – Perimeter Defense

Perimeter Defense is the first line of defense against cyberattacks. It is the outer layer of protection for our defense-in-depth approach to cybersecurity. It represents the processes, procedures, hardware, and software to protect critical systems such as SAP, customer data, and ultimately our grid from unauthorized access. When properly configured, the perimeter defenses should only permit those activities required to conduct business. In a perimeter defense security model, the perimeter technology prevents, absorbs, or detects attacks, thereby reducing the risk to critical back-end systems. Cybersecurity perimeter defenses include technologies such as firewalls and intrusion detection systems.

In addition, the Perimeter Defense program will continue to refine existing intrusion protection measures and implement new ones (such as systems with deep-scanning capabilities and advanced data analytics capabilities). This will help us more ably detect nefarious activity.

[30] Low latency refers to systems that require having a very low time interval between when a message is sent and when it is received.

This project will integrate these new tools and controls into our existing Perimeter Defense layer to create common, unified monitoring that lets us rapidly respond to security events.

1. Drivers Impacted

Perimeter Defense reduces the frequency of all drivers by, among other things, intercepting attempted communications and attacks from external attackers. It also helps us determine whether external communications are intended to harm SCE, including whether the communication is an attempt to trick or coerce a user into clicking internet links or providing information.

2. Outcomes & Consequences Impacted

Perimeter Defense also reduces the impact to all outcomes by preventing attacks from reaching and impacting other internal defense capabilities. Perimeter Defense addresses the initial attack step that is taken in most adversary campaigns, which is to utilize phishing messages or other social engineering tactics to:

- Convince or coerce an internal user to open a malicious e-mail attachment;
- Click on a Uniform Resource Locator (URL) that links to malware; or
- Trick the user into providing sensitive information such as user credentials to the attacker, or to an attacker-controlled website.

Perimeter Defense identifies and either automatically prevents the communication or alerts the user.

3. Control Options Modeled for C1 (Perimeter Defense)

Perimeter Defense is a core control within our defense-in-depth cybersecurity strategy. As such, when evaluating alternatives to this control, SCE contemplated different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools associated with the deployment of this control over the RAMP period. These options are represented through C1a, C1b, and C1c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options, and uses those results to build our proposed and two alternative mitigation plans.

D. C2 – Interior Defense

Interior Defense is a set of protection controls that are needed to:

- Secure SCE's internal business systems from unauthorized users, devices, and software that are attempting to access SCE's business systems; and
- Utilize analytics to prevent attacks from happening before they start.

Interior Defense efforts also help identify and block security breaches from personnel who already have authorized access to the systems. Users of SCE's business systems can propagate and/or launch malware[31] knowingly or unknowingly. Without the Interior Defense controls, SCE could not identify or react to an infected computer or malicious breach attempting to infect others on the network. By quickly identifying suspicious activity, SCE can take earlier action to minimize any potential damage from the attack.

The Interior Defense mitigation lets us monitor SCE's internal business network, in real-time and with advanced and integrated capabilities. This makes it difficult for unauthorized users to access our systems, and also protects against authorized users knowingly or unknowingly propagating cybersecurity attacks. This mitigation also make it harder for rogue devices or software to access SCE systems and confidential data or to cause business disruption. The mitigation will also address Advanced Persistent Threats (APT)[32] by using advanced data collection and analysis technologies that can quickly detect potential questionable activity.

To accomplish all of this, the Interior Defense mitigation program will:

- Extend SCE's Identity and Access Management system to newer generation security technology;
- Enhance and expand SCE's data collection capabilities to retrieve (and, as needed, collect) disparate pieces of data to form a clear picture of threats and attacks;
- Implement technology capabilities so that SCE can analyze collected information for security threats in a more automated and effective manner; and
- Initiate automated alerts when questionable activity is detected. This will let us stay ahead of possible threats and help prevent attacks from happening.

1. Drivers Impacted

Interior Defenses are designed to reduce D2 (Insider Threat), as well as any external threat D1 (External Actor) or D3 (Supply Chain) threat that successfully bypasses the Perimeter Defenses. A threat that originates on or accesses the SCE internal network will be neutralized by Interior Defense at the endpoint (workstation, laptop, or server). When an attack occurs to a system that is directly connected to the SCE internal network via physical interface, we counter the attack through access controls that disallow unauthorized systems.

[31] Malware is software that is intended to damage or disable computers and computer systems.

[32] Advanced Persistent Threats (APT) mean a network attack where an unauthorized person gains access to a network and remains undetected on the network for a long period of time. Typically, an APT attack is launched to steal data rather than to damage the network or organization.

2. Outcomes & Consequences Impacted

Interior Defense affects all outcomes. All attack paths require that Interior Defenses be bypassed regardless if the attacker is attempting physical or network access. Interior Defense prevents malware and malicious software from spreading once they are inside SCE.

3. Control Options Modeled for C2 (Interior Defense)

Interior Defense is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C2a, C2b, and C2c, which are variants of the Interior Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

E. C3 – Data Protection

The Data Protection program safeguards the computing environment housing SCE's core information. Among other things, this program will protect confidential SCE information that resides on all computing devices from unauthorized use, distribution, reproduction, alteration, or destruction.

The Data Protection program will leverage specialized technology to better protect and encrypt data fields within files, enhance access controls to protect sensitive business information, and secure business information stored at external sites that host SCE business systems. In addition, this mitigation program will implement enhanced controls for granular data protection by deploying Data Loss, Categorization, and Identification tools. These controls will:

- Automate data classification by tying together the different systems that contain data and the ability to classify them;
- Monitor and alert unauthorized access to business information by leveraging the monitoring and data analysis environment with new toolsets;
- Manage business information that is saved on personal devices;
- Manage and restrict the copying of business information to portable devices.

1. Drivers Impacted

All Drivers are impacted by the functions provided by this mitigation. The use of data classification and role-based access controls prevents unauthorized users and attackers from accessing sensitive SCE information.

2. Outcomes & Consequences Impacted

Outcome 2 (Exfiltration of ICS/SCADA/CEII data) is primarily affected by Data Protection, which restricts access to specifically-classified SCE data to a limited group of users. This blocks an attacker that is trying to locate valuable information about SCE's operations or customers in order to sell or release that information.

3. Control Options Modeled for C3 (Data Protection)

Data Protection is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C3a, C3b, and C3c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

F. C4 – SCADA Cybersecurity

This project provides enhanced security measures by implementing risk-reduction methods specifically tailored for SCE's SCADA systems. SCE's SCADA systems remotely control and monitor the electric grid.

SCADA Cybersecurity protects legacy and future industrial control systems that are currently connected via routable networks. We need better visibility, detection, and protection controls to secure these environments from evolving threats. This control does the following:

- Builds a secure network to protect the administrative interfaces of critical tools;
- Develops device access controls to secure how operators interact with control systems;
- Develops user access controls to secure role-based access to least-required privileges.[33] This is a more secure profile for user access;
- Implements next generation malware protections to identify malware;
- Deploys vulnerability management tools to search for and identify known vulnerabilities;
- Provides data encryption services;
- Develops system monitoring services;
- Implements threat intelligence integration tools that can automatically take in intelligence to monitor and analyze potential and actual threats; and

[33] The Principle of Least Privilege is the idea that no more than the very minimum number of people should have access to information and resources as necessary for legitimate purposes.

- Procures government-sponsored secure technology to defend against advanced attacks.

1. Drivers Impacted

All three Drivers are impacted by this mitigation. SCADA protection makes it far more difficult for attackers to enter the electric grid network without proper credentials. External actors and the supply chain must pass through controls that are similar to Perimeter Defense, but applied at the edge of the grid network. Insider Threat actors will also be challenged by this mitigation.

2. Outcomes & Consequences Impacted

This mitigation affects outcomes O3 (Loss of control with denial of use of electrical systems), O4 (Adversary control with disruption to electrical systems) and O5 (Adversary control with physical damage to / destruction of electrical system). SCADA protection assesses the network at periodic intervals to help make sure that new vulnerabilities are not present. In addition, there are network visibility points that can be used to monitor, and provide alerts on, various conditions that may indicate abnormal operations or the presence of an attacker. Like Data Protection and Internal Defense, there are role-based access control measures to prevent unauthorized SCE users from modifying the grid environment.

3. Control Options Modeled for C4 (SCADA Cybersecurity)

SCADA Cybersecurity is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C4a, C4b, and C4c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

G. C5 – Grid Modernization Cybersecurity

Grid Modernization Cybersecurity will protect our distribution systems by detecting, isolating, fixing or removing, and restoring compromised systems and devices to normal as quickly and efficiently as possible.

Modernizing the electric grid will lead to new capabilities to support the evolving use of the distribution system. This will require many new applications that extend grid networks into a two-way relationship with customers and third parties. The distributed intelligence from grid modernization presents new cybersecurity challenges. Addressing these cybersecurity challenges requires a combination of infrastructure, applications, and threat intelligence initiatives.

Infrastructure service layers are needed to extend strong cybersecurity controls to the edges of the grid network. New grid applications must be designed with cybersecurity controls throughout their lifecycle by integrating strong access controls, secure communications, and secure programming code. Integrating cybersecurity operations with external threat intelligence-sharing organizations will help us more effectively respond to incidents and improve our investigation capabilities.

Also, cybersecurity must be integrated into each component of grid modernization. Grid Modernization Cybersecurity will defend against known cybersecurity threats by implementing controls and protections, including:

Secure Administration Environments: Cybersecurity adversaries primarily target privileged credentials, such as system administrators and super users.[34] Losing control of these accounts can result in catastrophic system failures and prolonged service outages. The most common attacks on these accounts are privilege escalation attacks or malicious insiders. Designing secure administration environments helps prevent and deter these threats.

Device Access Controls: A fundamental cybersecurity control involves profiling, authenticating, and monitoring devices connected to the network. Forcing an attacker to launch an attack from a compromised SCE-controlled device is far easier to defend against than a device that the attacker itself has designed. Additionally, IP-connected devices that are located outside of physically secure buildings (such as cameras or control systems in the spaces where electrical components are stored and deployed) can be impersonated and their connections used to launch an attack. This mitigation will address these threats.

User Access Controls: Among other things, this effort will protect against improper control of grid system operations.

Advanced Malware Protections: Current grid system networks primarily employ a blacklisting strategy (signature-based virus scanning) to protect against malware. Blacklisting strategies are only able to detect *known* malware. As shown in both the Stuxnet[35] and

[34] Super users have special privileges that allow them to make changes to access and configurations within and across systems.

[35] Stuxnet is malware designed to target the Siemens Programmable Logic Controllers (PLCs) connected to Iranian uranium enrichment centrifuges that degraded the quality of the output while damaging the centrifuges. *See* David Kushner, *The Real Story of Stuxnet* (February 26, 2013), *available at* https://spectrum.ieee.org/telecom/security/the-real-story-of-stuxnet.

BlackEnergy attacks on critical infrastructure (discussed above), an attacker will very likely customize malware to avoid being detected by blacklisting systems. Since grid systems are more rarely reprogrammed or updated than business networks, grid computer systems are ideal for taking a whitelisting[36] approach. Application whitelisting authorizes a specific set of applications and processes to run on a given system while preventing all other applications or code from executing. This effort will comprehensively implement this approach across grid system networks wherever feasible.

Vulnerability Management: Since the beginning of software development, mistakes have been made in code or security control oversights that render a system vulnerable to a known attack. These attacks can be logged in a publicly available repository that contains computer and software vulnerability information. A vulnerability management system (VMS) is critical to tracking known vulnerabilities and facilitating remediation.

1. Drivers Impacted

All drivers are impacted by this mitigation, since it applies multiple layers of protection at the edge of the access to our network, as well as internally within the SCE grid environment. The mitigation prevents unauthenticated users and unauthorized SCE personnel from accessing the network. The mitigation also allows us to monitor different network connection and transportation types (such as fiber and radio frequency) for misuse.

2. Outcomes & Consequences Impacted

Components of this mitigation have impacts on outcomes O3 (Loss of control with denial of use of electrical systems), O4 (Adversary control with disruption to electrical systems) and, O5 (Adversary control with physical damage to / destruction of electrical system). User Access Controls prevent an attacker from using default credentials to access the grid environment. Advanced Malware Protection prevents attackers' programs from running on grid assets. And Device Access Controls restrict the pathways that an attacker can use in attempting to move through the grid network towards more critical components. (This is what the attackers did in the NotPetya malware attack and the 2015 Ukraine electrical outage attack.)

3. Control Options Modeled for C5 (Grid Modernization Cybersecurity)

Grid Modernization Cybersecurity is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented

[36] Whitelisting involves controls within software that permit known valid applications and code to run while prohibiting unknown or untrusted applications and code from running.

through C5a, C5b, and C5c, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

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IV. Mitigations

In the normal course of business, and as part of developing this RAMP report, SCE continually identifies more effective ways to mitigate this risk. Many of these new approaches are specific projects or tools that are incorporated into each program discussed in Section III above. While SCE continually evaluates and incorporates new and innovative projects and tools into each control program, we believe we cannot publicly disclose the details of these efforts.[37]

As part of the RAMP process, SCE did identify and evaluate a potential new mitigation opportunity that in the future could help address a growing cybersecurity risk. Please see Table IV-1 below.

Table IV-1 – Inventory of Mitigation[38]

Inventory of Mitigations		Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
ID	Name				Proposed	Alt. #1	Alt. #2
M1	Accelerated Hardware Refresh	All	All	All			x

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE risk-models mitigations in this RAMP report.)

A. M1 – Accelerated Hardware Refresh

With the discovery and release of the design flaws in Intel and AMD processors named Meltdown and Spectre[39] there is a high probability that attackers will be developing software[40] to target these vulnerabilities. The vulnerabilities are present in an extremely large section of computing hardware. Currently, neither Intel nor AMD has issued processors for sale that are immune to this new class of vulnerability. As such, processor design vulnerabilities will likely

[37] SCE's cybersecurity's efforts are focused on protecting critical infrastructure. Therefore, a secure process for disclosing detailed tactics, techniques, and procedures is necessary to help ensure its protection. As discussed above, SCE can provide an in-person briefing in a closed setting upon request.

[38] Please note that in this table, SCE maps how the mitigation impacts drivers, outcomes, and consequences. For purposes of modeling this mitigation in RAMP, SCE only adjusts outcome probabilities over time.

[39] *See* Peter Bright, Meltdown and Specter: Here's what Intel, Apple, Microsoft, others are doing about it (January 5, 2018), *available at* https://arstechnica.com/gadgets/2018/01/meltdown-and-spectre-heres-what-intel-apple-microsoft-others-are-doing-about-it/

[40] *See* David Fisher and William G. Sanchez, *Detecting Attacks that Exploit Meltdown and Spectre with Performance Counters*,(March 13, 2018) *available a*t https://blog.trendmicro.com/trendlabs-security-intelligence/detecting-attacks-that-exploit-meltdown-and-spectre-with-performance-counters/

become known as "forever day" vulnerabilities[41] that may never be remediated in existing hardware with a longer-than-average refresh cycle period, such as industrial control systems (ICS) and related components within the grid environment.

To plan for such an event, this mitigation would accelerate the technical hardware refresh from the existing four-year cycle to a one- to two-year cycle, prioritized by business area. This would allow SCE to replace the vulnerable hardware with systems that are hardened and protected against the specific Meltdown and Spectre vulnerabilities, as well as the new class of processor design flaws.

1. Drivers Impacted

This mitigation will directly impact the viability of all three drivers in the cyberattack risk bowtie.

2. Outcomes & Consequences Impacted

This mitigation can serve to stop cyberattacks from advancing from Outcome 1 (No impact to service or data) to Outcome 5 (Adversary control with physical damage to / destruction of electrical system). As such, M1 will affect all outcomes and associated consequences.

[41] Due to the increased longevity of industrial equipment and control systems compared to the general-purpose computing platforms of IT, vulnerabilities are not easily fixed by manufacturer and vendor software patches or by releasing a new version of the technology. The threat will persist much longer in the Industrial Control System (ICS) networks. A critical vulnerability may never get patched or remediated in an ICS environment, and therefore may forever be at risk of being exploited. *See* Dan Goodin, *Rise of " forever day" bugs in industrial systems threatens critical infrastructure* (April, 9, 2012), *available at* https://arstechnica.com/information-technology/2012/04/rise-of-ics-forever-day-vulnerabiliities-threaten-critical-infrastructure/

V. Proposed Plan

Cybersecurity is inherently difficult to quantify. The risks and threats that we face as a utility in one of the largest metropolitan cities[42] in the world are vast and diverse. Trying to forecast the probability of successful breaches of our systems controls involves making a series of educated assumptions based on what we know about our existing defenses, the demographics and capabilities of our attackers, and the growth and complexity of the attacks we will face in the future. In addition, the risk of cyberattack has the potential to change significantly due to global politics and the associated actions of nation states. Cybersecurity threats are not limited to our service territory, but instead can originate from virtually anywhere across the world. Cybersecurity challenges can also be triggered or motivated by social unrest, political differences and upheavals, and religious and cultural factors.

Measuring the effectiveness of controls and mitigations becomes equally difficult when we don't have a base level of historical data and experience to draw from. Fortunately, SCE has not experienced a significant breach of our control systems yet.

Through the development of this RAMP report, SCE was able to take initial steps forward in quantifying the cyberattack risk to SCE, as well as the effectiveness of our controls and mitigations. This is truly a first-generation model, but one that SCE believes provides a strong foundation upon which to improve in the future.

SCE analyzed, from a historical perspective, the relative effectiveness of our cybersecurity controls and mitigations in addressing SCADA/ICS attacks that have occurred around the world over the past few years.[43] SCE used this analysis to inform the mitigation evaluation and risk spend efficiency calculations.

SCE has evaluated each control and mitigation discussed in Sections III and IV and has developed a Proposed Plan for addressing this risk, as shown in Table V-1 below.

[42] Los Angeles, as a service area, comprises a high density of customers to geographic areas, headquarters a great deal of the media/entertainment industry, and has a high profile in the news. Thus, a cyberattack in Los Angeles will be a much more reported-upon event and will provide the attackers with relatively higher visibility.

[43] Please refer to WP Ch. 6, pp. 6.7 – 6.9 *(Outcome-Based Risk Reduction Model Overview)* for further detail on this cyberattack outcome-based risk assessment.

Table V-1 – Proposed Plan (2018 - 2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Perimeter Defense	2018	2023	$80.8	$34.9	1.51	0.013	9.13	0.079
C2a	Interior Defense	2018	2023	$47.9	$23.7	0.91	0.013	5.83	0.082
C3a	Data Protection	2018	2023	$30.7	$16.7	0.02	0.000	0.03	0.001
C4a	SCADA Cybersecurity	2018	2023	$19.8	$19.9	0.46	0.012	3.04	0.077
C5a	Grid Modernization Cybersecurity	2018	2023	$169.2	$33.8	1.41	0.007	9.28	0.046
			Total - Proposed Plan	**$348.4**	**$129.0**	**4.31**	**0.009**	**27.32**	**0.057**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

SCE evaluated our internal defenses against cyberattack capabilities and threats. This evaluation indicated that SCE has implemented adequate cyber defense strategies for the threats that exist today. However, through developing this RAMP report, we have identified increased exposure and risk in the future. As such, in the Proposed Plan, SCE continues to deploy and enhance its defense-in-depth cybersecurity approach by maturing and expanding existing cybersecurity practices. In addition, SCE supplements this work with enhanced capabilities, tools, and resources to address the growth of cyberattack risks at a reasonable level of spend.

The Proposed Plan carries forward the scope of work from our existing activities, and adds additional training, penetration testing, and vulnerability assessments. Training is essential in helping ensure that SCE personnel are up-to-date on the latest technology and techniques used to protect and operate the grid network. Vulnerability assessments performed by independent and trusted third parties evaluate how SCE manages risks associated with vulnerabilities in the network environments. These assessments can also serve as checkpoints for ongoing projects. Use of penetration testing allows SCE to see:

- What an adversary would identify as key assets for compromise;
- What attack paths and techniques apparently would succeed within the SCE environment; and
- How practically effective the security mitigations are in preventing, mitigating, or detecting an attack.

B. Execution feasibility

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities and the technical limitations of our internal computing and operational systems. The Proposed Plan is feasible and prudent to execute.

C. Affordability

The Proposed Plan strikes a reasonable balance between cost and risk reduction. This plan is only slightly more expensive (<5%) than the Alternative Plan #1, but delivers nearly twice the amount of risk reduction. In addition, the RSE of this plan is approximately 40% greater than the Alternative Plan #1.

The Proposed Plan does not deliver as much risk reduction, nor at the level of RSE, as Alternative Plan #2 does. However, Alternative Plan #2 requires much greater costs to deliver these benefits.

SCE contemplated whether to pursue Alternative Plan #2, but chose not to for the following reasons: (1) SCE must balance the need to invest in cybersecurity on the one hand, versus the need to spend to address other risks and meet other important objectives on the other hand; (2) at this time, our evaluation indicates that the Proposed Plan represents a reasonable level of commitment and spend over the RAMP period; and (3) SCE does not believe that deploying M1-Accelerated Hardware Refresh (a notable feature of Alternative Plan #2) is an operationally practical, technologically mature, or fiscally prudent choice at this time. This is discussed further in Section VII, where we examine Alternative Plan #2 in more detail.

D. Other Considerations

Advances in the sophistication of cyberattack threats and the deployment of new attack methods may render the Proposed Plan ineffective. SCE must predict where the threat will go in the future. If we have not predicted this correctly, the mitigations laid out in the Proposed Plan may not be sufficient. In addition, global politics, social unrest, and war can potentially lead to increased numbers of, and greater sophistication of, attacks by nation-states on our electric system. As discussed previously, SCE builds, maintains, and operates critical energy infrastructure that could be more susceptible to attack should the global environment change.

VI. Alternative Plan #1

SCE evaluated other options to address the cyberattack risk and developed an alternative mitigation plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 - 2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Perimeter Defense	2018	2023	$80.8	$37.8	0.68	0.006	3.97	0.033
C2b	Interior Defense	2018	2023	$47.9	$22.7	0.59	0.008	3.79	0.054
C3b	Data Protection	2018	2023	$30.7	$15.4	0.01	0.000	0.01	0.000
C4b	SCADA Cybersecurity	2018	2023	$19.8	$9.2	0.17	0.006	1.12	0.039
C5b	Grid Modernization Cybersecurity	2018	2023	$169.2	$26.4	0.74	0.004	4.82	0.025
	Total - Alternative Plan #1			**$348.4**	**$111.5**	**2.19**	**0.005**	**13.72**	**0.030**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

Similar to the Proposed Plan, the Alternative Plan #1 continues to deploy SCE's defense-in-depth cybersecurity approach. This plan then adds modest incremental resources (fewer than the Proposed Plan) to increase certain cybersecurity capabilities to address a growing cyber threat.

B. Execution Feasibility

The Alternative Plan #1 represents a reduced scope of work for each mitigation program relative to the Proposed Plan. Since SCE believes the Proposed Plan can be executed, this plan should likewise be feasible to execute.

C. Affordability

This Alternative Plan #1 represents the least-cost option. While this is the least-cost option, the risk spend efficiency for this plan is the lowest out of the three mitigation plans identified. Alternative Plan #1 provides the lowest amount of funding for cybersecurity testing and will limit strategic upgrades to newer technologies.

If we eliminate or reduce vulnerability assessments and penetration tests, we will decrease the security capabilities of our IT networks. We will not be able to independently evaluate and proactively remediate technical vulnerabilities that can be exploited by an attacker to compromise SCE assets.

D. Other Considerations

As discussed in the Proposed Plan, if we have not adequately predicted the growing threat, the mitigations laid out in this plan may not be sufficient.

VII. Alternative Plan #2

SCE evaluated other options to address this risk and developed another alternative mitigation plan as shown in Table VII-1.

Table VII-1 - Alternative Plan #2 (2018 - 2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1c	Perimeter Defense	2018	2023	$80.8	$50.0	1.61	0.012	9.88	0.075
C2c	Interior Defense	2018	2023	$47.9	$30.0	1.67	0.021	10.76	0.138
C3c	Data Protection	2018	2023	$30.7	$20.9	0.02	0.000	0.03	0.001
C4c	SCADA Cybersecurity	2018	2023	$19.8	$11.5	0.43	0.014	2.82	0.090
C5c	Grid Modernization Cybersecurity	2018	2023	$169.2	$32.4	1.76	0.009	11.70	0.058
M1	Accelerated Hardware Refresh	2018	2023	$58.1	$0.0	0.44	0.008	2.84	0.049
	Total - Alternative Plan #2			**$406.5**	**$144.8**	**5.92**	**0.011**	**38.03**	**0.069**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

Alternative Plan #2 represents the most aggressive approach to expanding our cybersecurity defenses. This plan expands investing in our defense-in-depth controls (C1 – C5), and encompasses investing in a new mitigation, M1 (Accelerated Hardware Refresh). This new mitigation will address hardware-level vulnerabilities that exist in Intel and AMD processors made in the last 20 years.[44] In developing this plan, SCE considered global events, political situations, technological advancements, the rapid incorporation of technology into and across our business, and the persistent advancement of threats against our business.

B. Execution feasibility

While possible, this plan would require a significant operational effort to execute in short order. SCE would have to identify, evaluate, procure, and train a larger number of cybersecurity experts in a shorter period of time than in the Proposed Plan. This may prove difficult in a cybersecurity market that is already facing resource shortages. In addition, the number of additional, valuable tools that would need to be procured through this plan would require time and coordination to test, install, and deliver across the enterprise.

[44] The Pentium Pro (released in 1995) was the first Intel processor to use speculative execution, which is the basis for the Meltdown and Spectre related vulnerabilities. AMD processors are built with the same capabilities. *See* Joel Hruska, *What is Speculative Execution* (January 10, 2018) *available at* https://www.extremetech.com/computing/261792-what-is-speculative-execution.

Finally, this mitigation plan includes mitigation M1 (Accelerated Hardware Refresh), which would reduce the period of time between laptop and personal computer refreshes within SCE. That period is roughly four years today, and would drop to roughly two years going forward. While the benefits of this mitigation could be significant, the operational implications of executing this mitigation could be equally as significant. Although the vulnerabilities of some models of processor hardware have been successfully identified, the capability of widespread attack has not been demonstrated.

SCE carefully considered the operational factors, personnel disruption, and financial considerations of this plan. We determined that in light of the risk factors and the relatively early stage of maturity of M1 (Accelerated Hardware Refresh) technologies, this may not be the prudent time to execute. In looking at the expected risk for a widespread event that could take advantage of discovered and potential undisclosed vulnerabilities, we believe that the additional spend is not currently justified. SCE will continue to monitor the status of the supply chain threat to determine if the risk increases. If the vulnerability impact increases, then SCE will reconsider this analysis and this mitigation option.

C. Affordability

This is the highest-cost plan that we considered. This plan also provides the greatest scope of work to increase our cyber defenses, and is forecast to reduce the most risk. The risk spend efficiency of this plan is comparable to the Proposed Plan, and higher than Alternative Plan #1. Due to the maturity of the technologies required to deploy this Alternative Plan #2, SCE could not justify the additional expenditures at this time.

D. Other Considerations

As discussed in the Proposed Plan, if we have not predicted the growing threat accurately enough, the mitigations laid out in Alternative Plan #2 may not represent the correct fit.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Modeling the risk of cyberattacks and the effectiveness of cybersecurity controls and mitigations was a challenge.

In examining asset-based risks, we can evaluate actual failure rates and equipment conditions, and leverage decades worth of utility data and information related to the performance on an asset. In contrast, cybersecurity does not have a similar breadth of data that we can draw upon when analyzing the risks. Additionally, unlike most asset-based risks, cyberattacks are ever-evolving; what we know today may not be applicable to where the threat goes tomorrow, a year from now, or five years from now. As a result, SCE had to leverage industry data wherever possible, develop prudent assumptions, and consult with industry experts to validate our approach to this risk evaluation.

SCE recognizes that not capturing indirect, or secondary impacts from risk events can underestimate the potential magnitude of a risk. This is especially true for the cyberattack risk. If a cyberattack were to successfully compromise the grid and cause a widespread and extended blackout, there are very real safety and financial consequences that would result. These impacts are not captured in this chapter. We look forward to evaluating this issue further, to determine if there is a way to reasonably and credibly incorporate these indirect impacts into future risk analyses.

B. Data Collection & Availability

Most organizations, especially those in the utility and energy sector, are reluctant to share sensitive data on their cybersecurity operations and defenses. SCE faced two data challenges in this RAMP filing. First, most of the data that we do have relating to our control systems cannot be shared publicly. Doing so would expose our critical systems to attack. As such, the data that we can share as part of this RAMP filing related specifically to SCE is limited. Second, to our knowledge, most utility and energy companies follow the same data sensitivity protocols as we do. It can be very difficult to find relevant industry data, when most companies do not report and expose their vulnerabilities publicly.

C. Performance Metrics

SCE has a corporate goal around protecting critical infrastructure and customer data. SCE also collects internal cybersecurity metrics to measure the effectiveness of our cybersecurity efforts and the threats that we are seeing against our company. Some examples are metrics related to our enterprise phishing exercises, patching, and number of penetration attempts on the network.

In addition, there are several emerging metrics such as utilizing the Department of Energy Electric Sector Cybersecurity Capability and Maturity Model (C2M2). This model helps organizations evaluate, prioritize, and improve cyber capabilities. SCE uses a third party security vendor to conduct our C2M2 to compare results year over year.

SCE also leverages BitSight security ratings, which are similar to consumer credit scores, to address cyber risk on supply chain vendors. We also benchmark at a high level with other utilities to compare performance and spend. We will continue to use these metrics to inform our cybersecurity plans and strengthen our defense-in-depth capabilities to protect SCE from cyberthreats.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Employee, Contractor, and Public Safety

Chapter 7

Rosemead CA
November 15, 2018

Contents

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I. Executive Summary

A. Overview

In this chapter SCE discusses actions we take to protect our employees and contractors ("workers"), and members of the public from safety risks that can result when a worker performs one of the following acts:

- Incorrectly executing work due to knowingly or unknowingly violating a procedure, policy, or rule;
- Failing to identify, correct, and/or account for hazardous conditions or work practices;
- Incorrectly operating a vehicle;
- Following incorrect processes or system designs;
- Not being fit for duty;
- Lacking necessary skills or qualifications.

The chapter analyzes incidents that occur in the field, in office environments, and in vehicles. The chapter distinguishes between field incidents that involve electrical assets (e.g. working with energized components) and those that do not involve electrical assets (e.g. falling from a ladder).

This chapter describes two compliance activities:[1]

- Safety Compliance (CM1 & CM2): These activities represent a substantial portion of SCE's safety efforts, addressing areas such as worker protection from falls, working in confined spaces, and safe work around electrical hazards. Work in these areas involves establishing company standards and programs, developing and implementing work practices, and developing and delivering training.

In addition to the compliance activities, this chapter describes two controls:[2]

- Safety Controls (C1): This includes programs related to recognition and injury assistance.

[1] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[2] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

- Contractor Safety Program (C2): This includes a range of activities related to establishing qualification requirements for contractors, continually evaluating contractor safety performance, and making field-based assessments and observations.

Finally, this chapter describes seven mitigations, including:[3]

- Safety Culture Transformation (M1a & M1b): SCE's strategic approach to improve the safety of our workers and the public; presented with two variations based on the type of training and the incorporation of electronic tablets.
- Industrial Ergonomics (M2): Program for ergonomics for industrial or field activities.
- Office Ergonomics (M3a & M3b): Enhancements to existing office ergonomics programs; presented with two variations of tools.
- Driver Safety (M4a & M4b): Driver assessment and training; presented with two variations based on the population targeted for the training.

SCE has developed three risk mitigation plans for consideration:

- The Proposed Plan builds on existing safety programs, while adding new efforts such as the Safety Culture Transformation Program and ergonomics programs.
- Alternative Plan #1 offers an expanded version of the Safety Culture Transformation Program in the Proposed Plan, while adding additional activities related to ergonomics and driver safety.
- Alternative Plan #2 strikes a middle ground between the Proposed Plan and Alternative Plan #1. Alternative Plan #2 offers the core programs proposed in the Proposed Plan, and adds a more limited version of the driver safety program featured in Alternative Plan #1.

[3] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

B. Scope

The scope of this Chapter is defined in Table I-1.

Table I-1 - Chapter Scope

In Scope	• Acts performed by an SCE employee and/or contractor ("SCE worker") that lead to an adverse outcome for SCE workers or the public.
Out of Scope	• Vehicle incidents due to human error by a member of the public. • Criminal and/or malicious acts performed by SCE workers that harm the worker, other workers and/or the public.[4] • Public safety incidents occurring as a result of the public's unauthorized interactions with SCE's electric and/or non-electric assets. • Incidents that occur solely as a result of failed electrical and non-electrical assets and equipment.[5] • Acts that do not result in an adverse outcome. SCE does not track or maintain records of such acts, and cannot reasonably forecast the number of acts that SCE workers perform that do not result in an adverse outcome.[6]

[4] We evaluate workplace violence and insider threats in Chapter 6 - Cyber Attack and Chapter 9 - Physical Security.

[5] We examine the safety consequences associated with SCE assets failing in these chapters: Chapter 4 – Building Safety, Chapter 5 – Contact with Energized Equipment, Chapter 8 – Hydro Asset Safety, Chapter 10 – Wildfire, and Chapter 11 – Underground Equipment Failure.

[6] SCE monitors close calls—incidents in which an adverse outcome did not occur, but could have—and implements learnings from such incidents as appropriate.

C. Summary Results

Table I-2 summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		**Mitigation Plan**		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Safety Controls	X	X	X
C2	Contractor Safety Program	X	X	X
M1a	Safety Culture Transformation – Core Program	X		X
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards		X	
M2	Industrial Ergonomics	X	X	X
M3a	Office Ergonomics – Core Program	X	X	X
M3b	Office Ergonomics – Additional Software		X	
M4a	Driver Safety Training – Full Training Population		X	
M4b	Driver Safety Training – Limited Training Population			X
Mean (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	6.98	6.98	6.98
	Risk Reduction (MRR)	0.53	0.59	0.54
	Residual Risk	6.45	6.39	6.44
	Risk Spend Efficiency (RSE)	0.040	0.039	0.040
Tail Average (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	10.01	10.01	10.01
	Risk Reduction (MRR)	0.41	0.47	0.43
	Residual Risk	9.60	9.54	9.58
	Risk Spend Efficiency (RSE)	0.031	0.031	0.032

Figures represent 2018 - 2023 annual averages.

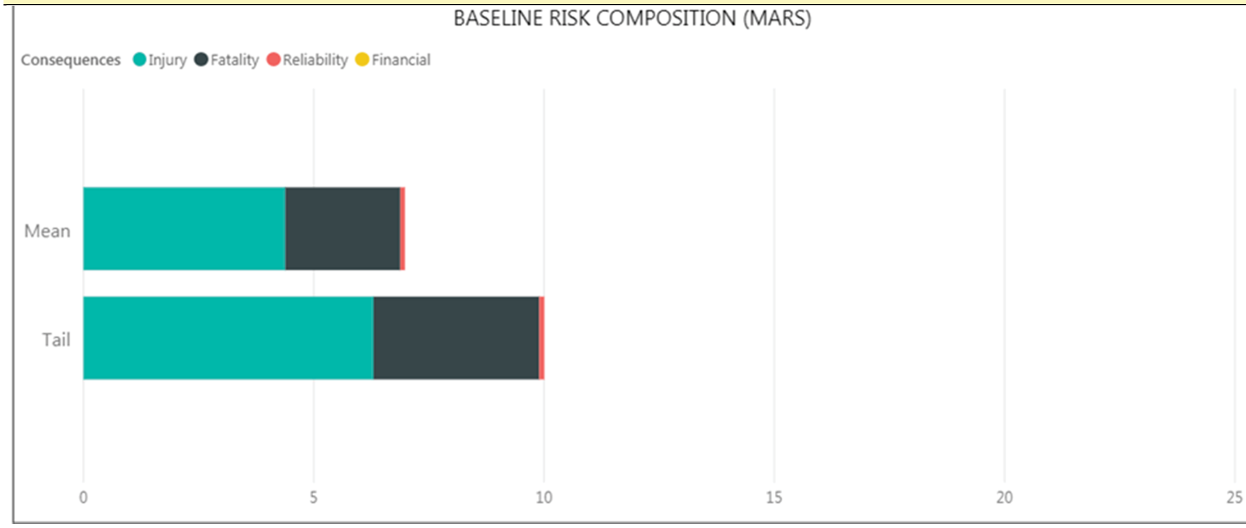
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 summarizes the baseline risk including compliance controls, prior to application of controls and mitigations, and depicts the composition of the consequences. The majority of this risk is related to safety consequences, with marginal impact to reliability.

Figure I-1 - Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

The safety of our customers, the general public, and our workers is of utmost importance to SCE. The work that we perform to maintain our electric system is diverse, and includes activities such as:

- Installing and replacing transmission and distribution utility poles, towers, and electrical conductors;
- Managing vegetation on or around overhead equipment;
- Maintaining electrical assets at over 800 substations;
- Maintaining administrative and operational facilities that support grid operations;
- Using vehicles to transport workers, tools, and equipment to work sites; and,
- Performing office-related work activities.

We perform these potentially hazardous tasks in order to provide safe, reliable, affordable, and clean electricity to our customers across a 50,000 square mile service territory.

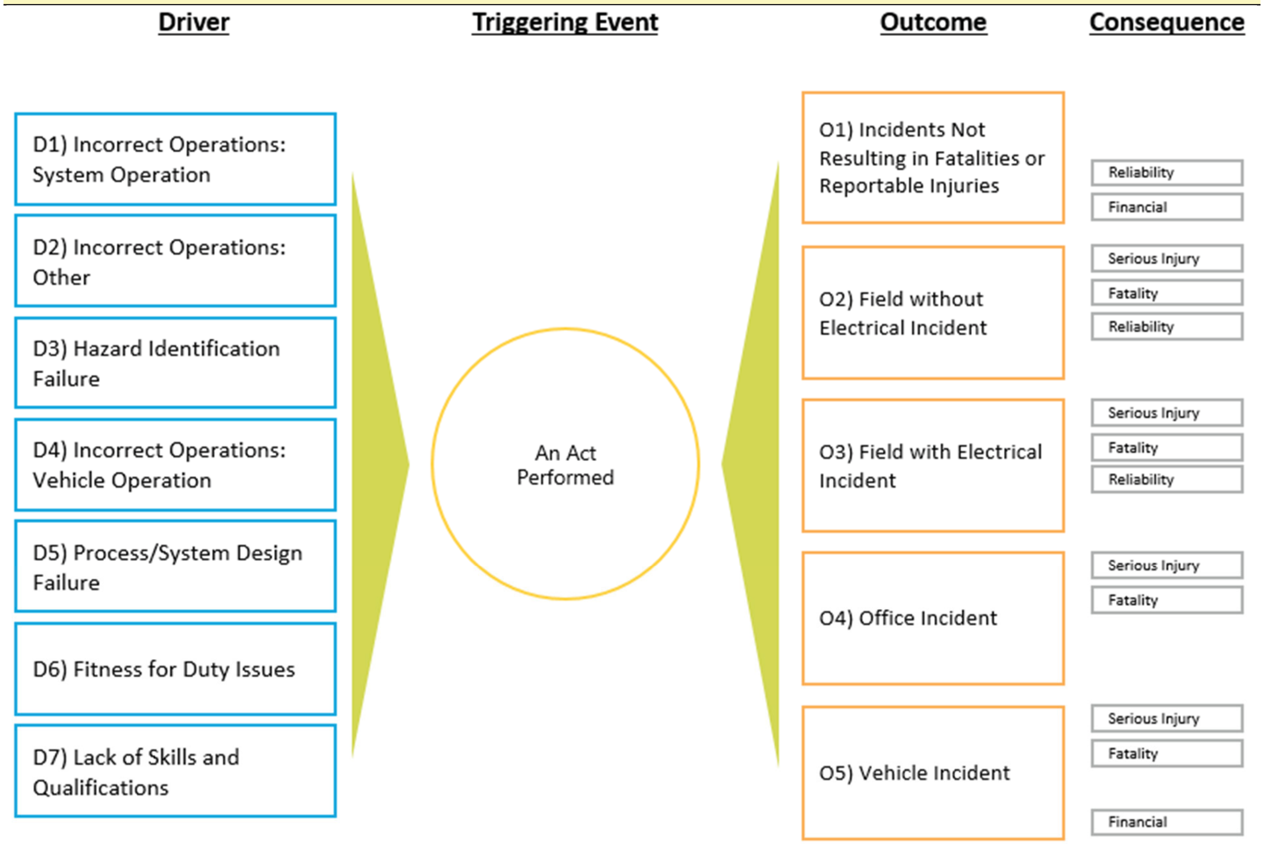
The number of SCE employees and contractors is a key factor in the exposure that this risk presents. In 2017, SCE's workforce consisted of approximately 21,000 workers (counting both employees and contractors).[7] Approximately half are classified as field workers. SCE defines field workers as SCE employees or SCE-authorized contractors who perform more than 50% of their job responsibilities outside of the office environment, including working on or operating SCE's electrical system. SCE defines office workers as SCE employees or SCE-authorized contractors who perform more than 50% of their job responsibilities inside an office environment. Historically speaking, the majority of incidents that result in serious injuries or fatalities occur in the field.

SCE constructed a risk bowtie, as shown in Figure II-1, to evaluate this risk. Each component of the bowtie represents a critical data point in evaluating this risk.[8]

[7] The number of workers used is based upon actual SCE employee count, plus an estimated count of contract workers. That estimated count is derived from the number of contractor work hours recorded in 2017 (i.e., 2,000 contractor work hours was translated to represent 1 worker). It is difficult to capture total exposure to the public. Exposure is broader than our customer base, and includes any person within SCE's service territory with whom SCE workers come in contact.

[8] Please refer to WP Ch. 7, pp. 7.1 – 7.4 (*Baseline Risk Assessment*).

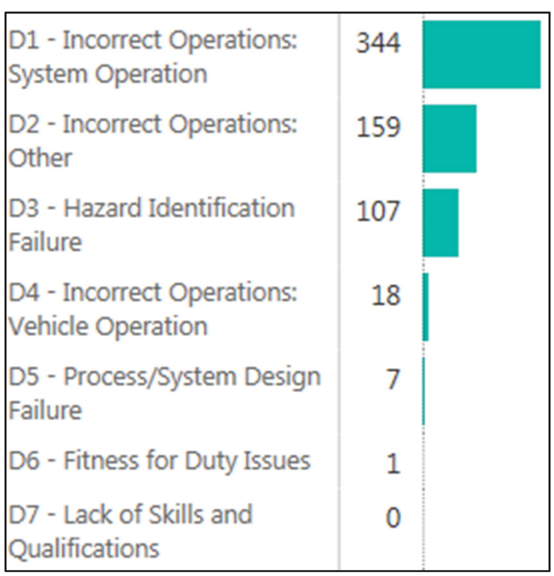
Figure II-1 – Employee, Contractor and Public Safety Risk Bowtie



B. Drivers

SCE identified seven primary drivers. These drivers and their annual frequencies are shown in Figure II-2.

Figure II-2 – 2018 Projected Driver Frequency



1. D1 – Incorrect Operations: System Operation

D1 represents acts performed due to a worker incorrectly executing field work that relates to operating the electrical system. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule. Examples include improper operation of switches on electrical equipment, or inappropriately energizing or de-energizing a transformer or other electrical equipment. These types of actions can cause an incident such as an arc flash, which could result in a serious injury.

SCE estimated an annual frequency of 344 for this driver based on analyzing historical outage occurrences that were associated with worker actions over the 2014-2017 time period.[9]

2. D2 – Incorrect Operations: Other

D2 represents acts performed due to a worker incorrectly executing work that does not pertain to electrical systems or vehicle operations. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule. Examples include incorrectly operating tools and equipment, lifting or carrying materials in a way that is ergonomically unsound, or falling from heights due to improper use of fall protection equipment.

SCE estimated an annual frequency of 159 for this driver based on analyzing historical employee and contractor incident and injury data over the 2014-2017 time period.

3. D3 – Hazard Identification Failure

D3 represents acts performed due to a worker failing to identify, correct, and/or account for hazardous conditions in the work environment or work practices. For example, hazardous conditions can include inadvertently positioning oneself in harm's way (e.g., standing beneath a suspended load).

SCE estimated an annual frequency of 107 for this driver based on analyzing historical employee and contractor OSHA data over the 2014-2017 time period.

4. D4 – Incorrect Operations: Vehicle Operation

D4 represents acts performed due to a worker's incorrect operation of a vehicle. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule.

SCE estimated an annual frequency of 18 for this driver based on analyzing historical employee and contractor incident and injury data over the 2014-2017 time period.

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[9] After every unplanned outage on the SCE distribution system, SCE staff reviews and verifies information on the number of customers affected by the outage, the duration of the outage, the cause of the outage, and the location of the outage. In addition, SCE staff reviews all outages with durations of twenty-four hours or more.

5. D5 – Process/System Design Failure

D5 represents acts performed due to a worker following incorrect processes or system designs. As work environments change and new technologies are used in the workplace, existing processes or system designs may no longer promote the safest work practices.

SCE estimated an annual frequency of 7 for this driver based on analyzing incident cause evaluation data over the 2014-2017 time period.

6. D6 – Fitness for Duty Issues

D6 represents acts performed while a worker is not fit for duty. Workers are expected to come to work fit for duty, meaning they cannot be under the influence of legal or illegal drugs, alcohol, or have physical or mental conditions that prevent them from accomplishing their job functions safely.

SCE estimated an annual frequency of 1 for this driver based on analyzing human resources data and incident cause evaluation data over the 2014-2017 time period. The relatively low frequency here is a reflection that the worker not being fit for duty must actually result in a qualifying triggering event.

7. D7 – Lack of Skills and Qualifications

D7 represents acts performed due to a worker's lack of necessary skills or qualifications. Skills and qualifications include physical and mental aptitude and knowledge gained through training.

SCE estimated an annual frequency of 0.5 for this driver based on analyzing incident cause evaluation data over the 2014-2017 time period. Again, the relatively low frequency is a reflection that the driver must actually result in a triggering event.

C. Triggering Event

The triggering event is defined as an act performed by an SCE worker that leads to an adverse outcome for an SCE employee, contractor, or a member of the public.

The triggering event frequency is composed of the estimated annual frequencies of D1 – D7. As shown in Figure II-3, SCE forecasts a flat growth rate for the drivers and triggering event frequency over the RAMP period. This forecast is based upon SCE's historical safety performance coupled with the observation that current controls on their own have already achieved their anticipated results in reducing incidents. Absent implementing planned mitigations, we would expect comparable safety performance in the foreseeable future.

Figure II-3 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	Total
Employee, Contractor and Public Safety							
Baseline	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**
Driver							
D1 - Incorrect Operations: System Operation	344.17	344.17	344.17	344.17	344.17	344.17	**2,065.03**
D2 - Incorrect Operations: Other	159.32	159.32	159.32	159.32	159.32	159.32	**955.95**
D3 - Hazard Identification Failure	106.56	106.56	106.56	106.56	106.56	106.56	**639.38**
D4 - Incorrect Operations: Vehicle Operation	18.49	18.49	18.49	18.49	18.49	18.49	**110.93**
D5 - Process/System Design Failure	7.38	7.38	7.38	7.38	7.38	7.38	**44.29**
D6 - Fitness for Duty Issues	0.99	0.99	0.99	0.99	0.99	0.99	**5.95**
D7 - Lack of Skills and Qualifications	0.49	0.49	0.49	0.49	0.49	0.49	**2.96**
Total	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**

D. Outcomes

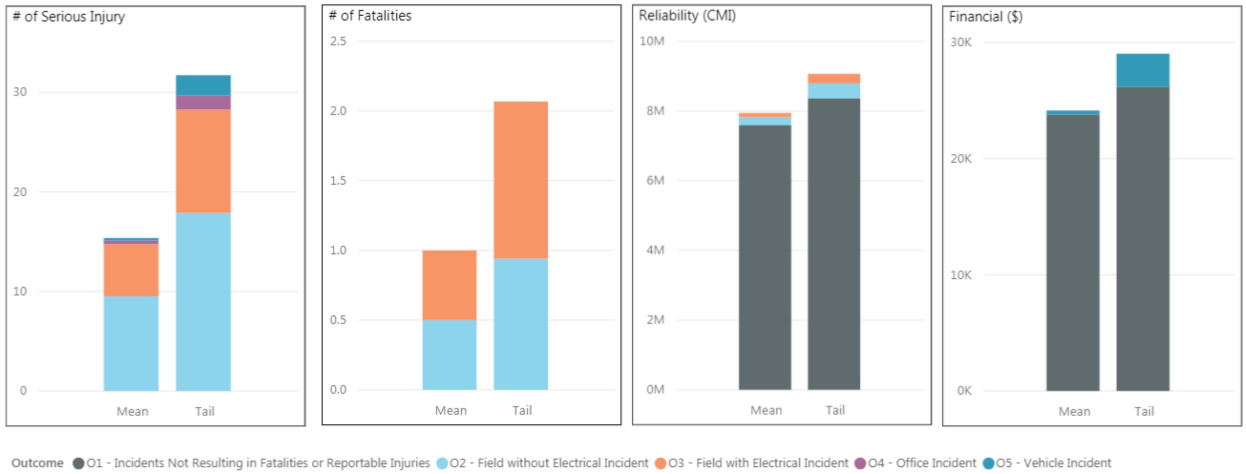
SCE has identified five outcomes, which are described in greater detail below. Figure II-4 indicates the relative likelihood of each outcome should the triggering event occur.

Figure II-4 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Incidents Not Resulting in Fatalities or Reportable Injuries	97.5 %	
O2 - Field without Electrical Incident	1.6 %	
O3 - Field with Electrical Incident	0.8 %	
O4 - Office Incident	0.1 %	
O5 - Vehicle Incident	0.0 %	

Figure II-5 illustrates the composition of the modeled baseline risk in terms of each consequence. The majority of serious injuries and fatalities occur through O2 (Field without Electrical Incident) and O3 (Field with Electrical Incident). In addition, the vast majority of the reliability and financial impacts for this risk occur through O1 (Incidents Not Resulting in Fatalities or Reportable Injuries). The sections that follow detail the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)



As noted in Chapter I (RAMP Overview), SCE evaluated several potential criteria that could define the serious injury threshold for purposes of this RAMP Report. SCE selected the serious injury definition from the Edison Electric Institute (EEI). While SCE is moving toward the EEI standard for classifying and analyzing internal injury data, the historical data available for this chapter did not always use the EEI criteria in classifying serious and non-serious injuries. For example, SCE's historical safety data from contractors is typically based on classifying an injury as serious if the injury must be reported to the California Division of Occupational Safety and Health (also known as Cal/OSHA).

As explained below, in most cases this chapter used historical data on Cal/OSHA reportable injuries as a proxy for estimating serious injuries on a forward-looking basis under the RAMP framework.

1. O1 – Incidents Not Resulting in Fatalities or Reportable Injuries

This outcome captures incidents in which an injury may have occurred, but the injury did not meet the threshold for reporting to Cal/OSHA. For example, if an incident in the field, in the office, or in a vehicle did not result in a Cal/OSHA reportable injury or fatality, it is included in this outcome. However, if an incident resulted in a Cal/OSHA reportable injury, it would be included in one of the other outcomes (O2 – O5).

This outcome does not include incidents in which a fatality occurred (these incidents would be included in one of the outcomes described below).

Because this outcome excludes fatalities and incidents with injuries that were serious enough to be reported to Cal/OHSA, it is only modeled in terms of the reliability and financial consequences. However, we wish to emphasize that SCE's safety approach is oriented toward reducing all injuries, not just the relatively rare incidents that result in serious injuries.

Potential consequences from O1 are summarized on an annualized basis in Table II-1. Reliability impacts are associated with service interruptions caused by worker error during field incidents. Financial costs are associated with damage due to vehicle incidents. For O1, the estimate of annual impacts is 7.6M customer minutes of interruption (CMI) and $24K of financial harm on a mean basis; and 8.4M CMI and $26K of financial harm on a tail-average basis.

Table II-1 – Outcome 1 (Incidents Not Resulting in Fatalities or Reportable Injuries): Consequence Details

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	Available data was limited to property damage related to vehicle incidents in scope for this outcome for years 2014-2016.
Model Outputs	NU - Mean			7.6M (CMI)	$24K
	NU - Tail Avg			8.4M (CMI)	$26K

NU = Natural Unit

2. O2 – Field without Electrical Incident

This outcome includes incidents involving field workers that do not directly involve SCE electrical assets. Examples include, but are not limited to, an employee fracturing his/her ribs after falling from a ladder, or an employee suffering from heat exhaustion.

Potential consequences from O2 are summarized on an annualized basis in Table II-2. Serious injuries and fatalities are associated with the harm that was caused by the incident. Reliability impacts are associated with service interruptions caused by worker error. For O2, the estimate of annual impacts is 9.51 serious injuries, 0.50 fatalities, and 231K customer minutes of interruption (CMI) on a mean basis; and 17.87 serious injuries, 0.94 fatalities, and 435K customer minutes of interruption (CMI) on a tail-average basis.

Table II-2 – Outcome 2 (Field without Electrical Incident): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.	Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	
Model Outputs	NU - Mean	9.51	0.50	231K (CMI)	
	NU - Tail Avg	17.87	0.94	435K (CMI)	

3. O3 – Field with Electrical Incident

This outcome includes incidents involving field workers and SCE electrical assets. Examples include arc flash burns from opening a 12 kV line disconnect in the wrong position, or making contact with energized components while working in an underground structure.

Potential consequences from O3 are summarized on an annualized basis in Table II-3. Serious injuries and fatalities are associated with the harm that was caused by the incident. Reliability impacts are associated with service interruptions caused by worker error. For O3, the estimate of annual impacts is 5.25 serious injuries, 0.50 fatalities, and 121K customer minutes of interruption (CMI) on a mean basis; and 10.39 serious injuries, 1.13 fatalities, and 275K customer minutes of interruption (CMI) on a tail-average basis.

Table II-3 – Outcome 3 (Field with Electrical Incident): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.	Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	
Model Outputs	NU - Mean	5.25	0.50	121K (CMI)	
	NU - Tail Avg	10.39	1.13	275K (CMI)	

4. O4 – Office Incident

This outcome includes incidents involving office workers. Examples include a worker slipping and falling while walking and fracturing a bone, or another worker dislocating a joint while walking.

Potential consequences from O4 are summarized on an annualized basis in Table II-4. Serious injuries and fatalities are associated with the harm that was caused by the incident.

For O4, the estimate of annual impacts is 0.36 serious injuries and nearly 0 fatalities on a mean basis; and 1.41 serious injuries and nearly 0 fatalities on a tail-average basis.

Table II-4 – Outcome 4 (Office Incident): Consequence Details

Outcome 4		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Injuries tracked by SCE that met the EEI definition for years 2014-2017. This criteria was used due to a lack of Cal/OSHA reported incidents during 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.		
Model Outputs	NU - Mean	0.36	0.00		
	NU - Tail Avg	1.41	0.00		

5. O5 – Vehicle Incident

This outcome includes vehicle incidents associated with SCE workers. Examples include a worker striking a streetlight while driving an SCE vehicle, or rear-ending another vehicle. This outcome excludes incidents that occurred outside of the course and/or scope of employment.

Potential consequences from O5 (Vehicle Incident) are summarized on an annualized basis in Table II-5. Serious injuries and fatalities are associated with the harm that was caused by the incident. Financial costs are associated with property damage. For O5, the estimate of annual impacts is 0.25 serious injuries, nearly 0 fatalities, and $0.3K of financial harm on a mean basis; and 2.04 serious injuries, nearly 0 fatalities, and $2.8K of financial harm on a tail-average basis.

Table II-5 – Outcome 5 (Vehicle Incident): Consequence Details

Outcome 5		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.		Property damage related to vehicle incidents for years 2014-2016.
Model Outputs	NU - Mean	0.25	0.00		$0.3K
	NU - Tail Avg	2.04	0.00		$2.8K

III. Compliance & Controls

Table III-1 maps controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.

***Table III-1 – Inventory of Compliance & Controls*[10]**

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Safety Compliance – Standards, Programs & Policies	Not Modeled	Not Modeled	Not Modeled	$0	$11.20
CM2	Safety Compliance – Technical Training	Not Modeled	Not Modeled	Not Modeled	$0	$57.50
C1	Safety Controls	All	-	-	$0	$0.30
C2	Contractor Safety Program	All	-	-	$0	$0.16

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Safety Compliance – Standards, Programs & Policies

Title 8 of the California Code of Regulations and Title 29 of the Code of Federal Regulations require that employers maintain safety standards, programs, and policies for the welfare of their employees. Consequently, SCE maintains a number of safety standards, programs and policies. Some examples are listed below:[11]

- Bloodborne Pathogens Exposure Control Standard
- Chemical Management
- Confined Space Program
- Fall Protection Standard
- Hazardous Energy Control
- Hearing Conservation Program
- Heat Illness Prevention Program
- Hot Work Program[12]
- Injury and Illness Prevention Program
- Respiratory Protection Program

[10] Please refer to WP Ch. 7, pp. 7.5 – 7.18 (*RAMP Mitigation Reduction Workpaper*).
[11] Please refer to WP Ch. 7, pp. 7.20 – 7.21 (*Safety Standards, Programs, and Policies*).
[12] Hot work activities include soldering, welding, pipe-cutting, heat-treating, grinding, thawing pipes, hot riveting, torch-applied roofing and any other application involving heat, sparks or flames.

- Safety Incident Management Standard

These requirements and processes are designed to mitigate risk to workers when followed. On a routine basis, SCE reviews its standards, programs and policies to help ensure they are accurate, effective and up-to-date.

B. CM2 – Safety Compliance – Technical Training

This compliance activity focuses primarily on providing training to employees working in the field. Similar to CM1 (Safety Compliance – Standards, Programs & Policies), SCE is required to perform these activities according to Title 8 of the California Code of Regulations and Title 29 of the Code of Federal Regulations, as well as function-specific regulations according to Department of Transportation and Federal Aviation Administration.

Examples of these programs include: Distribution Apprentice Lineman Program, Transmission Groundman and Apprentice Lineman Programs, Distribution Groundman and Lineman Training Programs, Lineman & Electric-Crew Foreman Skills Refresher, Troubleman Skills and Knowledge Training, Transmission Skills, Apparatus Technician, Construction Field Forces (CFF) Electrician, CFF Battery Electrician, and Transmission Estimator.

C. C1 – Safety Controls

SCE maintains safety programs above and beyond federal and state regulations. These programs include the Safety Recognition Program, Injury Assistance Program, and Functional Movement Screening.

The Safety Recognition Program provides a forum to recognize our employees for their commitment to working safely. It enables formal and informal recognition by both managers and employees for various safety behaviors through online thank-you cards and awards.

SCE implemented the Injury Assistance Program (IAP) in August 2014. The IAP is an injury assistance hotline to provide access to trained medical professionals (nurses and/or physicians). These medical professionals can assess non-emergency medical situations over the telephone, and provide care advice. The IAP hotline guides the employee through self-care options (when appropriate), or directs the employee to the nearest available clinic within the SCE Medical Provider Network, and expedites paperwork for quicker appointments. This program is voluntary and can help prevent minor injuries from potentially becoming more serious.

SCE provides the Function Movement Screening (FMS) for T&D field employees. FMS uses a customized stretching and muscle-stabilizing sequence prescribed for each participating employee. FMS improves the physical performance of the employee, assisting them with the basic movement functions of their job. Quarterly assessments of participants provide individual results and facilitate sustainability of the exercise program.

1. Drivers Impacted

The Safety Recognition Program reduces all drivers, as it reinforces positive behaviors and safe work practices. Notably, FMS reduces driver frequency for D2 (Incorrect Operations: System Operations) and D3 (Hazard Identification Failure) by providing customized assessments for individuals to perform work safely with an improved understanding of their physical abilities.

2. Outcomes and Consequences Impacted

The primary focus of this control is to reduce the drivers of this risk. While there are benefits associated with reducing the severity of minor injuries (e.g. strains, sprains, soft-tissue injuries, etc.), we do not model those benefits in this RAMP as we are only capturing safety consequences related to serious injuries and fatalities.

D. C2 – Contractor Safety Program

This control focuses on the work SCE performs to improve the safety of our contractors. In 2017, SCE reached a Settlement Agreement[13] with the CPUC regarding several contractor safety practices.[14] As SCE is obligated to adhere to the Settlement, it represents a compliance obligation. Because this is SCE's primary program related to contractor safety, and because the Settlement was enacted recently, SCE determined that it was more appropriate to treat these activities as a control. This allows the contractor safety program to be included in the analytical modeling and to be measured in terms of its impact on drivers and/or outcomes.

Key aspects of the program are summarized in Table III-2.

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[13] D.17-06-028. Decision Adopting the Settlement Agreement re Investigation 15-11-006, Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Edison Company (U338E); Notice of Opportunity for Hearing; and Order to Show Cause Why the Commission Should not Impose Fines and Sanctions for the September 30, 2013 Incident at a Huntington Beach Underground Vault.

[14] SCE had been performing contractor safety activities in various capacities prior the Settlement Agreement.

Table III-2 – Key Elements of Contractor Safety Program	
Retention of a Third Party Administrator	Review and qualify contractors identified as performing higher-risk activities.
Expanded Criteria for Contractor and Subcontractor Qualification	Additional criteria for an entity to become qualified to contract with SCE, such as Occupational Safety and Health Administration (OSHA) citation history, fatality history, and significant public safety events.
Enhanced Field Safety Observations	SCE contractor liaisons conduct regular field safety observations.
Hazard Assessment and Environmental, Health, and Safety Plans	Identifying health and safety issues and verifying that contractors have strong hazard mitigation plans in place.
Quality Assurance Reviews	Detailed on-site assessments of selected high-risk contractors to validate the implementation of written contractual safety commitments.

In addition to the above elements, SCE is also engaging with contractor company leaders to leverage core tenets of safety culture transformation efforts occurring at SCE.

3. Drivers Impacted

All drivers are impacted by this mitigation. Improved processes and controls related to contractor qualification and performance are expected to reduce driver frequencies.

4. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this control.

IV. Mitigations

Beyond the compliance and control activities discussed above, SCE has identified potential new ways to further mitigate this risk. These activities are summarized in Table IV-1, and discussed in more detail below.

Table IV-1 – Inventory of Mitigations[15]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan			RAMP Implementation	
					Proposed	Alt. #1	Alt. #2	Start	End
M1a	Safety Culture Transformation – Core Program	All	-	-	x		x	2018	2021
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	All	-	-		x		2018	2023
M2	Industrial Ergonomics	D2, D3, D5, D7	-	-	x	x	x	2018	2023
M3a	Office Ergonomics – Core Program	D3, D5, D7	-	-	x	x	x	2018	2023
M3b	Office Ergonomics – Additional Software	D3, D5, D7	-	-		x		2018	2023
M4a	Driver Safety Training – Full Training Population	D3, D4, D7	O5	S-I		x		2018	2023
M4b	Driver Safety Training – Limited Training Population	D3, D4, D7	O5	S-I			x	2018	2023

Consequence abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations <u>are</u> modeled in this report, and are addressed in Section IV.

A. M1a – Safety Culture Transformation – Core Program

SCE implemented the Safety Culture Transformation program in 2018 after completing design and planning work in 2017. While this mitigation is currently scoped to implement through 2021, SCE plans to continually assess our progress, and will augment this approach as necessary to achieve the desired safety culture and associated injury reduction.

M1a (Safety Culture Transformation – Core Program) represents a strategic approach to improving the safety of our workers and the public. This mitigation provides changes needed to improve our safety performance through an improved safety culture. These efforts will focus primarily on SCE employees.

M1a is composed of six focus areas that are represented in Table IV-2 and described in more detail below.

[15] Please refer to WP Ch. 7, pp. 7.5 – 7.18 (*RAMP Mitigation Reduction Workpaper*).

Table IV-2 – Six Focus Areas of Safety Culture Transformation Program

#	Focus Area	Objective
1	Common Understanding of Safety Culture Change	Build a common understanding and vision for our future-state safety culture.
2	Leadership and Talent Management	Implement safety culture training and safety leadership assessments, and incorporate safety into the hiring process.
3	Safety Communications	Align and improve safety communications, processes, and messaging across the company.
4	Hazard Awareness and Risk Management	Provide and enhance tools to improve the ability of employees to identify hazards and make safe decisions for how to proceed.
5	Safety Data Strategy	Improve integrity and integration of safety-related data across the company to enable data-driven insights.
6	Safety Structure, Governance, and Programs	Build foundation for successful safety culture change through organizational structures, safety governance, and refinement of existing safety programs to align with our safety culture vision.

1. Common Understanding of Safety Culture Change

This focus area provides the organization with context for the importance of safety culture change and the means to achieve this change. These efforts began with communications with employees to share the results of our 2017 Safety Culture Assessment,[16] which identified areas for improvement and established a common understanding of where SCE stands today and needs to go in the future.

Next, SCE senior leadership defined the company's future state safety culture; this guides the tone of safety communications, the development of safety training, the enhancement of tools and processes to identify and mitigate risks, and the evolution of safety programs discussed in the following sections.

2. Leadership and Talent Management

The Leadership and Talent Management focus areas addresses three main activities: (a) Training, (b) Assessment for New Leaders & Hiring Practices.

a. Training

Under M1a (Safety Culture Transformation – Core Program), SCE employees will participate in a new safety culture training with three components called *Switch, Engage,*

[16] SCE's 2017 Safety Culture Assessment was conducted to understand the current state of SCE's safety culture and identify areas for reinforcement as well as opportunities for improvement.

and *Connect*. This training provides cognitive-based tools to enable participants to make safer choices by obtaining a deeper understanding of thought processes.

SCE has begun implementing these trainings with field employees, since high-hazard job classifications generally involve higher safety risk. Field employees will experience *Switch* through a two-day, in-person training class.

After attending *Switch,* field leaders will attend *Engage,* a two-day, in-person leadership workshop that provides practical tools for implementing *Switch* concepts, supporting a strong safety culture, and influencing safety behaviors. Three months later, these leaders will meet a third time for a one-day, in-person *Connect* training, which will focus on leading effective teams and creating an environment where safety is physically and psychologically valued.

In 2019, SCE will begin *Switch, Engage* and *Connect* training with the rest of the company. To manage costs and to accelerate adoption, SCE is utilizing a blended roll-out approach for enterprise implementation. This approach proposes initial computer-based training to cover basic *Switch* and *Engage* introductory concepts. The computer-based training will be followed by one-day, in-person classes with activities and discussion of the cognitive-based tools and techniques. *Connect* will be in-person.

b. Assessment for New Leaders & Hiring Practices

The words and actions of leaders can significantly influence the safety choices made by their teams. This component of M1a will roll out a leadership profile assessment to facilitate hiring new leaders who demonstrate the personal attributes necessary to create a safe, supportive, and inclusive work environment. This assessment will be implemented for new leaders, beginning with field functions, and then expanded to the entire enterprise.

This effort also aims to align talent pipeline processes, such as recruiting and selecting candidates, with core safety competencies and values. It implements a more targeted approach to finding and selecting job talent that will align with our evolving safety culture.

3. Safety Communications

Here, we aim to redesign the safety communications structure, processes, and messaging approach so that communications resonate with employees and promote individual ownership of safety.

SCE's 2017 Safety Culture Assessment noted that there is a lot of "noise" around safety. For example, the volume of safety awareness campaigns deployed at the enterprise, organizational, and grassroots levels has led to numerous safety messages. The variation in safety messaging has caused confusion and diluted the impact of safety communications.

We have developed a consistent, enterprise-wide safety communications strategy and voice using the "Own It" theme (i.e., encouraging employees to "own" their personal safety). SCE has, and will continue to, reduce and refine the number of safety-related communications and emails to focus on quality and consistency over quantity.

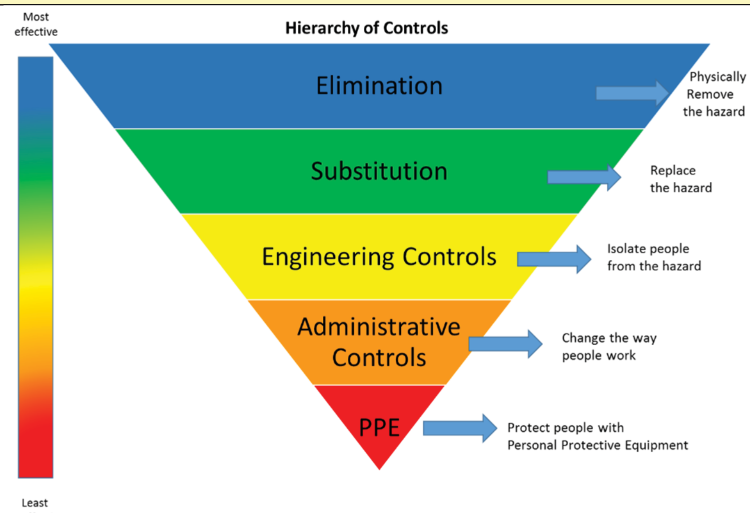
4. Hazard Awareness and Risk Management

This focus area will provide four tools (job hazard analysis, hierarchy of controls, error prevention tools, and tailboards) to improve the ability of employees to identify hazards in the workplace and make safe decisions on how to proceed.

A Job Hazard Analysis (JHA) is a tool used by field employees to identify the hazards associated with performing specific job tasks. It provides actions to reduce the risk of injury before any injury occurs. As part of M1a (Safety Culture Transformation – Core Program), JHAs were created for tasks with high incident or injury rates, as well as those that have potential to cause serious injury.

The Hierarchy of Controls (shown below in Figure IV-1) provides a systematic approach to manage hazards and make safe decisions. Implementing the hierarchy of controls when planning, designing, and performing work guides us in considering controls that range from more effective (removing the hazard) to, in relative terms, less effective (i.e. PPE, which can protect a worker in case of an incident, but does not prevent the incident from occurring in the first place).[17] Put simply, this hierarchy helps reduce the risk of serious injury or fatality by making sure that we utilize the most effective controls first and more frequently.

Figure IV-1 – Hierarchy of Controls



[17] SCE is not suggesting that it is unimportant for front-line workers to wear PPE, or that rules and practices concerning PPE should not be followed.

SCE is expanding the use of error prevention tools and the understanding of human performance principles for all field employees. Human performance principles are based on understanding people and human nature, then finding ways to reduce their chances of making a mistake.[18] This effort will standardize the definition of, and training on, error prevention tools; this should reduce the chance that an incident or injury occurs while employees perform their work.

SCE has utilized tailboards, or pre-job briefings, for many years through structured forms that outline the work to be performed, the processes to be followed, and the potential safety hazards. However, the 2017 Safety Culture Assessment found that SCE's current tailboard process generally leads to a presentation format rather than a group discussion. The revised tailboard will provide the environment necessary to engage in group dialogue, which includes every participant giving input. We believe that by facilitating discussion, we will see greater engagement and greater identification and mitigation of hazards.

5. Safety Data Strategy

SCE does not currently have an integrated and comprehensive safety data architecture. For example, one system captures incidents impacting system reliability, while another system tracks employee safety incidents. This component of M1a (Safety Culture Transformation – Core Program) will develop and implement a comprehensive safety data architecture,[19] an integrated incident management system, a methodology for incident cause evaluations to improve the scope and quality of captured data, and capabilities in areas such as predictive analysis. With mechanisms in place to better collect, analyze and report data, SCE will increase its ability to identify major contributing factors that lead to incidents and close calls.

6. Safety Structure, Governance and Programs

This component of M1a (Safety Culture Transformation – Core Program) focuses on building the foundation for successful safety culture change through organizational structures, safety governance, and refinement of existing safety programs to align with our safety culture vision.

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[18] Three-way communication is an error prevention tool that provides mutual understanding and an opportunity to correct before an action is taken. For example, Worker A says, "I will be disconnecting position 1." Worker B responds, "Understood, you'll be disconnecting position 1." Worker A confirms, "Disconnecting position 1."

[19] This data architecture will align or integrate safety-related data, allowing communication and integration between various data systems.

a. Structure & Governance

As discussed in Chapter III (Safety Culture and Compensation Policies Tied to Safety), SCE has centralized our safety organizations into a single "Edison Safety" organization to allow for better company-wide alignment in our approach to creating a safe workplace. This component of M1a (Safety Culture Transformation – Core Program) will also focus on creating better alignment and communication amongst SCE's safety governance bodies, including the Executive and Senior Safety Councils, and OU Safety Councils.

b. Programs

The safety programs addressed here include the Craft Driven Safety Program, Safety Observation Program, and Safety Recognition Program.

1) Craft Driven Safety Program

This program was created in 2012 to improve safe work practices and enhance overall safety among field workers. This was a joint effort between SCE and IBEW Local 47 that implemented a peer-based safety performance management process. M1a will seek to improve this program by amplifying the transparency of safety-related incidents and communication of lessons learned.

2) Safety Observation Program

SCE's Safety Observation Program enables both manager-to-employee and peer-to-peer safety observations. A safety observation is the action of an individual observing the work of another individual in order to identify recommendations related to safe work performance (either positive or constructive). For example, an employee might submit an observation to recognize a peer for performing safe lifting practices, or an employee might submit an observation indicating that work was stopped at a field site due to the presence of unexpected hazardous conditions.

The data collected from safety observations is now available to all employees in the form of a dashboard, and supervisors are encouraged to utilize trends to take actionable steps to prevent future incidents.[20]

3) Safety Recognition Program

This component builds on the Safety Recognition Program described in C1 (Safety Controls), by rewarding employees who have displayed a continual pattern of safe behaviors and demonstrated that they personally value safety.

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[20] For example, if a negative trend in hand injuries is identified, a leader can reinforce work practices that mitigate risk during tailboards and can focus observations on hand protection.

7. Drivers Impacted

M1a will impact all drivers.

- D1 (Incorrect Operations: System), D2 (Incorrect Operations: Other) and D4 (Incorrect Operations: Vehicle): These drivers will be reduced through cognitive-based skills obtained in *Switch* training, effective sharing of lessons learned, use of hazard awareness and error prevention tools, availability of trends and predictive analytics to drive decision-making, and consistent leader reinforcement of safety behaviors, values and attitudes.
- D3 (Hazard Identification Failure): This driver will be reduced through cognitive-based skills obtained in *Switch* training, use of hazard awareness and error prevention tools, effective sharing of lessons learned, and consistent leader reinforcement of safety behaviors, values and attitudes.
- D5 (Process/System Design Failure): This driver will be reduced through a more efficient and aligned safety organizational model, predictive analytics to drive proactive measures, and industrial ergonomics technology to make data-driven decisions and improvements.
- D6 (Fitness for Duty Issues): This driver will be reduced as personal safety ownership is adopted and safety behaviors evolve.
- D7 (Lack of Skills and Qualifications): This driver will be reduced through skills obtained in *Switch, Engage* and *Connect* trainings, identifying leadership skills through profile assessments, and identifying and hiring top talent aligned with our safety culture.

8. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation. While some aspects of this mitigation (e.g., emphasizing PPE rather than leveraging the hierarchy of controls) may influence outcomes, we did not model these potential benefits, as such indirect impacts are likely not material to this program's primary benefits.

B. M1b – Safety Culture Transformation – Expanded Training & Electronic Tailboards

This mitigation, which is included in Alternative Plan #1, implements the same scope of work as M1a (Safety Culture Transformation – Core Program), but delivers two-day, in-person safety training to all employees, and supplies electronic tablets to field supervisors enabling easy access to hazard awareness tools.

Providing two-day, in-person safety training to all employees, rather than blending e-learning and in-person training for non-T&D employees, allows more time for interactive discussion with facilitators and peers.

Purchasing electronic tablets for field supervisors builds on the tools and processes discussed in M1a. This technology could enhance adoption and availability of hazard awareness tools, as critical documentation such as procedures, manuals, and job hazard analyses will be instantly available through apps at any given time to supervisors and crews anywhere in our service territory.

Most SCE field supervisors currently have Toughbook laptops that they can use for basic functions. Tablets have the potential to supplement the Toughbook by providing additional functionality and information access through apps. While promising, at this time more evaluation is needed for SCE to determine the appropriate extent and scope of integrating tablets into field work activities.

1. Drivers Impacted

Because this implements the same general functionality as M1a, it will impact the same drivers as M1a.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

C. M2 – Industrial Ergonomics

This mitigation enhances existing industrial ergonomics programs. Historically, SCE's industrial ergonomics efforts have emphasized injury prevention exercises as a primary hazard control (such as the FMS mentioned in C1 (Safety Controls)), and relied on dedicated field safety specialists to provide ergonomic guidance and employee coaching.

SCE is transitioning to a broader approach for industrial ergonomics, called *Set Up. Perform. Recover.*, which emphasizes three universal phases of work, regardless of the specific work environment. Key aspects of this industrial ergonomics program include:

- Physical Demands Analysis Evaluation: a process for examining postures, body movements, force, and duration.
- Wearable Technology: utilizing technology-embedded clothing that gives feedback, through computer-based systems, on muscle engagement and potential for overexertion injuries when performing certain work tasks.

1. Drivers Impacted

The adoption of the *Set Up. Perform. Recover*. approach by employees will reduce the frequency of D2 (Incorrect Operations: Other) and D3 (Hazard Identification Failure) as they relate to industrial ergonomics practices. Through workshops and training, employee knowledge of ergonomic risk factors will improve and the frequency of D7 (Lack of Skills and Qualifications) will be reduced. Wearable technology will provide data to inform specific solutions that should reduce the frequency of D5 (Process/System Design Failure).

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

D. M3a – Office Ergonomics – Core Program

This mitigation enhances existing office ergonomics programs and builds on the *Set Up. Perform. Recover.* concept mentioned in M2 (Industrial Ergonomics). In the office environment, this approach focuses on employee behaviors when interacting with equipment.

Each new office workstation will include a sit-to-stand desk, giving employees the flexibility to change their set-up to fit their ergonomic needs.

1. Drivers Impacted

Self-assessments and ergonomic training will improve employee knowledge of ergonomic risk factors and increase skills around ergonomic hazard identification, which should mitigate strain and sprain risks. Thus, D3 (Hazard Identification Failure) and D7 (Lack of Skills and Qualification) frequencies will be reduced. Sit-to-stand desks will reduce the frequency of D5 (Process/System Design Failure) by enabling employees to adjust their own workstations to their ergonomic needs.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

E. M3b – Office Ergonomics – Additional Software

This mitigation, which is included in Alternative Plan #1, provides employees with predictive data on how well they manage computer interactions such as keystrokes, mouse clicks, and regular breaks. The data collected through the software will also benefit SCE's ergonomics program managers by identifying at-risk groups for early intervention and injury prevention, and enabling future program elements to be tailored for maximum effectiveness.

1. Drivers Impacted

Drivers D3 (Hazard Identification Failure), D5 (Process/System Design Failure), and D7 (Lack of Skills and Qualification) will be impacted by this mitigation. This software will complement the overall ergonomics program by providing individual data and trends, reducing the frequency of D3 and D7. At both the individual and aggregate levels, this data and these trends will enable proactive improvements in processes, communications and behaviors, reducing the frequency of D5.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

F. M4a – Driver Safety – Full Training Population

This mitigation, which is included in Alternative Plan #1, would implement a training program for the approximately 4,200 SCE workers who are Class A license holders[21] or who are assigned to SCE vehicles.

1. Drivers Impacted

Drivers D3 (Hazard Identification Failure), D4 (Incorrect Operations: Vehicle), and D7 (Lack of Skills and Qualification) are impacted by this mitigation, as the training is expected to improve driving skills, abilities, and hazard avoidance.

2. Outcomes and Consequences Impacted

Serious Injury consequence of O5 (Vehicle Incident) will be impacted by this mitigation, as the training focuses on driving and vehicle safety, which improves a driver's ability to respond safely should an incident occur.

G. M4b – Driver Safety – Limited Training Population

This mitigation is identical to M4a (Driver Safety – Full Training Population), except the training population would be limited to the approximately 3,900 Class A license holders, in order to better implement and evaluate the training prior to introducing it to a larger population.

1. Drivers Impacted

SCE expects this mitigation to have the same impact at M4a on an individual basis, but its cumulative impact to this risk will be slightly lower due to being applied to a smaller training population.

2. Outcomes and Consequences Impacted

SCE expects this mitigation to have the same impact at M4a on an individual basis, but its cumulative impact to this risk will be slightly lower due to being applied to a smaller training population.

[21] The Class A license is for commercial vehicles with a Gross Vehicle Weight Rating of more than 10,000 pounds.

V. Proposed Plan

SCE has developed a Proposed Plan to mitigate this risk, as shown in Figure V-1 below.

Figure V-1 – Proposed Plan (2018 – 2023 Total Costs and Risk Reduction)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.33	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.384	0.33	0.300
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.06	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.769	0.05	0.600
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.21	0.012	0.16	0.009
			Total - Proposed Plan	**$ 27.6**	**$ 51.8**	**3.18**	**0.040**	**2.48**	**0.031**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

This plan reduces safety risk by implementing programs that are designed to shift the safety attitudes and behaviors of the entire organization. In addition to continuing SCE's existing safety controls, this plan implements the safety culture transformation program and ergonomics programs for industrial and office roles.

B. Execution feasibility

SCE believes that the Proposed Plan is feasible. SCE has the ability to continue the existing efforts within this plan, and the new activities build on existing capabilities and can be informed by historical experience. For example, the training in the safety culture transformation mitigation (M1a) covers a new training subject, but we have experience in the associated work and logistics. As described above, SCE has implemented this training program in 2018, and so far has not experienced issues with execution.

C. Affordability

The Proposed Plan costs $10.9M less than Alternative Plan #1, and $1.7M less than Alternative Plan #2. The RSE of the Proposed Plan (0.040) is higher than Alternative Plan #1 (0.039) and is the same as Alternative Plan #2 (0.040) on a mean basis.

The combination of existing and enhanced activities in the Proposed Plan represents a balance of reducing safety risks at prudent cost.

D. Other Considerations

The pace of organizational and programmatic changes in the safety areas has created a sense of "change fatigue" among SCE workers. SCE developed the Proposed Plan with this in mind. The safety culture transformation effort is intended to address this fatigue by establishing a stable foundation for future safety efforts. However, SCE appreciates that the sentiment of “change fatigue” may affect the effectiveness of the training found in the Proposed Plan. SCE plans to monitor and adjust implementation accordingly.

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VI. Alternative Plan #1

SCE developed Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	2018	2023	$ 13.0	$ 41.4	2.26	0.042	1.78	0.033
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.765	0.05	0.601
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.011	0.16	0.009
M3b	Office Ergonomics – Additional Software	2018	2023	$ 0.8	$ 0.3	0.06	0.060	0.05	0.047
M4a	Driver Safety Training – Full Training Population	2018	2023	$ -	$ 1.7	0.09	0.051	0.13	0.078
			Total - Alternative Plan #1	**$ 28.4**	**$ 61.6**	**3.52**	**0.039**	**2.83**	**0.031**

MARS = Multi-Attribute Risk Score

MRR = Mitigated Risk Reduction

RSE = Risk Spend Efficiency

A. Overview

This plan is premised on the idea of maximizing safety programs, tools, and training. It differs from the Proposed Plan in three ways:

- Replaces the proposed culture transformation program (M1a) with an expanded version that utilizes additional in-person training and electronic tailboards (M1b).
- Supplements the office ergonomics program (M3a) by adding ergonomics software (M3b).
- Adds a new driver safety program (M4a) that would be targeted at drivers with Class A licenses as well as drivers who are assigned to SCE vehicles that do not require a Class A license.

B. Execution feasibility

Because this plan would use more in-person training, logistical considerations are the primary factor affecting feasibility. For example, we may need more meeting rooms, additional qualified external facilitators, and in certain instances may need to rent external space to host the in-person training.

C. Affordability

Alternative Plan #1 is the highest cost option with the lowest RSE. Although this plan maximizes the implementation of potential mitigations that SCE could implement at this time, it does not offer a compelling value proposition. The higher cost of the plan ($10.9M more than the Proposed Plan) does not come with a commensurate risk reduction. Consequently, the RSE of Alternative Plan #1 (0.039) is lower than the Proposed Plan (0.040).

Expanding the Safety Culture Transformation to use more in-person training and electronic tailboards creates additional costs without a commensurate boost in risk reduction. While the ergonomics software would provide value to our overall ergonomic program, we believe the most appropriate approach at this time is to leverage the new ergonomic processes, such as *Set Up. Perform. Recover*. Once a stronger safety culture is established, we can continue to build upon our ergonomics program by implementing the software program, and leverage associated processes and data. Likewise, while driver safety training holds promise, further evaluation is needed as to whether now is the right time to implement.

D. Other Considerations

Due to the increased scope and extent of training and safety programs in this plan, it may exacerbate the "change fatigue" issues described above.

VII. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan # 2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.05	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.767	0.05	0.602
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.012	0.16	0.009
M4b	Driver Safety Training – Limited Training Population	2018	2023	$ -	$ 1.7	0.07	0.041	0.11	0.068
			Total - Alternative Plan #2	**$ 27.6**	**$ 53.5**	**3.24**	**0.040**	**2.60**	**0.032**

MARS = Multi-Attribute Risk Score

MRR = Mitigated Risk Reduction

RSE = Risk Spend Efficiency

A. Overview

Alternative Plan #2 includes all controls and mitigations as the Proposed Plan. In addition, this plan includes M4b (Driver Safety Training – Limited Training Population), which is the version of the driver safety program that is limited to drivers with Class A licenses.

B. Execution feasibility

Alternative Plan #2 features the same feasibility considerations as the Proposed Plan, with the additional logistical requirements of the driver training program. The limited incremental work would not significantly impact SCE's ability to execute this plan.

C. Affordability

Alternative Plan #2 adds a relatively small incremental cost ($1.7M) due to the addition of M4b, but it provides a commensurate risk reduction, leading to the same RSE value (0.040).

D. Other Considerations

As described in above in the explanations of the Proposed Plan and Alternative Plan #1, SCE is sensitive to "change fatigue" and of overwhelming workers with too many safety initiatives. With that in mind, SCE is evaluating whether the driver safety program for Class A license holders can be implemented in the short term along with the activities in the Proposed Plan. SCE has not made this determination at the time. However, SCE will continue to evaluate driver safety mitigations for potential further inclusion in the 2021 GRC.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Developing this RAMP chapter highlighted several opportunities to improve the ways we track, measure, and mitigate this risk.

1. The structure of the risk bowtie did not neatly align with how we historically captured safety-related data.

SCE had to use judgment to correlate historical data to specific drivers. Fortunately, improving how we collect, track, and evaluate safety data is an element of the Safety Culture Transformation program. For example, this effort will improve our cause evaluation processes, which will provide detailed information regarding incident causal factors that can better inform elements of the risk bowtie. Additionally, we are improving our contractor incident and injury reporting, which will provide details regarding causal factors and appropriate corrective actions for these incidents.

2. Focusing on serious injuries, and not all injuries, does not fully capture the risk associated with this chapter, as well as the full benefits of controls and mitigations.

For this RAMP report, SCE chose to evaluate four consequences: Serious Injuries, Fatalities, Reliability, and Financial. This approach is challenging, because the vast majority of safety incidents result in injuries are not severe enough to count as serious injuries. SCE takes every safety incident seriously, whether it is minor or serious. In many cases, a non-serious incident could have been serious.

SCE intends to further explore ways to incorporate both serious and non-serious injuries in its subsequent risk analyses. This way, we can evaluate the full benefits of controls and mitigations on reducing serious and non-serious safety outcomes.

3. While the RAMP probabilistic risk model helped us evaluate the effectiveness of our various safety controls and mitigations from a quantitative perspective, SCE expects our ongoing and emerging data collection efforts to further refine these analyses.

Developing this chapter required us to take a quantitative approach to understanding each control or mitigation’s effect on drivers, outcomes, and consequences. This was challenging in many cases (e.g., quantifying the impact of cultural change). In these cases, SCE attempted to use safety industry trends, case studies at other companies, and expert judgment.[22]

B. Data Collection & Availability

While developing this RAMP chapter, SCE identified areas for improvement in the availability and tracking of safety-related data. Some of these areas include capturing more granular information on safety incidents that occur, especially those that do not result in serious injuries or fatalities, and in a form that is more conducive to data analysis. Obtaining data on the financial costs of safety incidents (other than costs linked directly to the injury such as medical and worker's compensation) was also challenging. Much of the data analysis performed for this chapter required manually transposing and interpreting data across several datasets. This consumed substantial time and resources.

By deploying the Safety Data Strategy discussed in M1a (Safety Culture Transformation – Core Program), and expanding the scope and frequency of safety cause evaluations, SCE expects to improve the collection and availability of safety data. We intend to use the data to enhance our predictive modeling efforts and better target our safety analyses and mitigation approaches.

C. Performance Metrics

Table VIII-1 lists metrics that SCE currently tracks related to safety. This table is not an exhaustive listing of all safety metrics within the company. However, it reflects some of the more important metrics used to evaluate the company's safety performance. These metrics align to the drivers, outcomes and consequences of the risk bowtie developed for this chapter. They are the types of metrics that the compliance, controls, and mitigations in the Proposed Plan are intended to address.

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[22] Please refer to WP Ch. 7, pp. 7.19 *(Subject Matter Expert Qualifications)*.

Table VIII-1 – Performance Metrics and Targets

Metric	Description
# of Employee Serious Injury	Count of SCE employee serious injuries, as defined by EEI and OSHA classifications
# of Employee Fatality	Count of employee fatalities
Days Away, Restrictions and Transfers (DART) Rate	Frequency measurement of workplace injuries and illnesses that result in time away from work, restricted job duties, or permanent transfers to new positions
Lost Workday Case Rate	Frequency measurement of workplace injuries and illnesses that result in time away from work
OSHA Recordable Injury Rate	Frequency measurement of work-related injuries and illnesses (including DART incidents) that result in 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
# of Contractor Serious Injury	Count of contractor serious injuries, as defined by EEI and OSHA classifications, that perform work for SCE
# of Contractor Fatality	Count of contractor fatalities
# of Close Calls	Count of incidents reported by SCE workers where no personal injury was sustained, but where given a slight shift in time or position, injury easily could have occurred
# of Safety Observations	Count of observations submitted by SCE workers related to safety behaviors or hazard identification and mitigation
# of Employees trained in cognitive behavior skills	Count of employees trained through SCE's safety culture transformation program
# of inappropriate actions for vehicular operations	Count of incidents where SCE workers are performing inappropriate actions while operating vehicles

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Hydro Asset Safety

Chapter 8

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE operates a portfolio of 81 hydro dams which support 33 hydroelectric plants that provide a combined 1,153 MW of generating capacity.[1] The dams are typically in remote mountainous areas and situated to capture the energy from high-elevation rain and snowmelt that flows downward. Most dams were constructed in the early 20th century, with the oldest dating to 1893 and the most recent dating to 1986. Approximately 8% of the electricity that SCE delivered to its customers in 2017 was generated by its hydro portfolio.[2] As discussed below, SCE already performs a number of compliance tasks and controls that cost-effectively mitigate the hydroelectric plant risks. Therefore, SCE's Proposed Plan recommends continuing these controls and does not contain incremental activities.

SCE approached its analysis of hydro dam risk by building on its existing Dam Safety Risk Assessment Program. SCE's Dam Safety Risk Assessment Program was initiated in 2008 and modeled after hydro dam risk management best practices established by the U.S. Bureau of Reclamation. The approach is based on identifying the potential ways a specific dam could fail, known as Potential Failure Modes (PFMs), then evaluating the likelihood of occurrence and the consequence of each PFM. SCE's hydro risk analysis presented in this RAMP chapter builds on this work.

SCE defined the risk event (i.e. the center of the bowtie) as the Uncontrolled Rapid Release of Water (URRW).[3] The scope is defined by dams with a hazard classification of "high-hazard" or greater as designated by the California Department of Water Resources Division of Safety of Dams (DSOD) and/or the Federal Energy Regulatory Commission (FERC).[4] For

[1] SCE also operates two dams on Catalina Island that support its potable water supply.
[2] Edison International and Southern California Edison 2017 Annual Report, p. 120, *available at* https://www.edison.com/content/dam/eix/documents/investors/corporate-governance/2017-eix-sce-annual-report.pdf
[3] Future RAMP filings may expand scope to include appurtenant structures such as tunnels, flumes, flowlines and penstocks.
[4] Hazard classification is based on potential downstream impacts to life and property should the dam fail when operating with a full reservoir, as defined in the Federal Guidelines for Inundation Mapping of Flood Risk Associated with Dam Incidents and Failures (FEMA P-946, July 2013). A classification of "High" is given for a dam where one or more fatalities would be expected. DSOD created an "Extremely High" category in 2017 to identify dams that are expected to cause considerable loss of human life or result in an inundation area with a population of 1,000 persons or more). Five of SCE's 28 high-hazard dams are classified as Extremely High-Hazard.

convenience, SCE will refer to these facilities as high-hazard dams. SCE believes that this is an appropriate scope for the analysis, as the facilities have been identified by the relevant federal and/or state regulators as having the greatest potential to cause loss of human life.

This chapter discusses three drivers that could potentially lead to URRW: seismic events, flooding, and failure under normal operations. Risk outcomes are described in terms of three categories: the facility is inoperable and there is no significant inundation; there is inundation of an unpopulated area; there is inundation of populated and unpopulated areas. The overall likelihood of a catastrophic failure of one of SCE's 28 high-hazard dams is estimated as one failure every 175 years.

This chapter describes four compliance activities:[5]

- Hydro Operations (CM1): This includes monitoring and controlling reservoir levels and flows, routine observation and data collection by trained personnel, and regular testing of critical systems.
- Hydro Maintenance (CM2): This includes repairing minor/localized deterioration and maintaining operability of critical systems.
- Dam Safety Program (CM3): This program utilizes qualified engineers, supported by internal and external Subject Matter Experts, to help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.
- External Inspections (CM4): Regular regulatory inspections are performed by the FERC and DSOD. Additionally, independent Consultant Safety Inspections are performed at five-year intervals for each dam in accordance with Chapter 18 of the Code of Federal Regulations (18 CFR) Part 12D.

In addition to the compliance activities, this chapter describes six controls:[6]

- Seismic Retrofits (C1): Reinforcing dams to withstand seismic loading and/or making improvements to maintain seismic restrictions on reservoir levels.
- Dam Surface Protection (C2): Protecting upstream dam surfaces with geomembrane liner systems.[7]

[5] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[6] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

[7] A geomembrane liner extends the life of a dam by reducing the degradation that can occur from water entering concrete pores and then freezing.

- Spillway Remediation and Improvement (C3): Repairing and improving structures used to safely pass water flows from flooding events.[8]
- Low-Level Outlet Remediation and Improvement (C4): Repairing and improving systems used to draw down dam reservoir levels in a controlled manner.
- Seepage Mitigation (C5): Repairing or enhancing the structure and/or drainage systems of earthen dams to inhibit the initiation and progression of internal erosion.
- Instrumentation / Communication Improvements (C6): Improving instrumentation and communication systems used to detect conditions that may indicate dam failure.

Finally, this chapter describes three potential mitigations:[9]

- Proactively removing high-hazard dams to proactively reduce risks (M1).
- Relocating campgrounds or campsites within potential inundation zones (M2).
- Purchasing private residences within potential inundation zones (M3).

SCE's has developed three risk mitigation plans for consideration:

- The Proposed Plan consists of continuing all current controls (C1 through C6).
- Alternative Plan #1 adds proactive removal of a small number of dams (M1) to the Proposed Plan.
- Alternative Plan #2 adds relocation of campgrounds and campsites (M2) and purchase of private residences (M3) to the Proposed Plan (but does not add M1).

This chapter also includes a technical appendix that pilots an analytical approach for a longer-term risk analysis. SCE selected Hydro Asset Safety as the pilot for this alternative approach due to the long-lived nature of many of its risk controls and mitigations. The technical appendix uses the same bowtie components, controls, and mitigations that were evaluated in the short-term analysis.

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[8] A spillway is a structure that is used to make controlled releases of water flows from a dam into a downstream area, typically the riverbed of the dammed river itself. Water normally flows over a spillway only during flood periods.

[9] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are addressed in Section IV of this chapter.

B. Scope

The scope of this Chapter is summarized in Table I-1.

Table I-1 – Chapter Scope

In Scope	• URRW due to failure of a high-hazard dam caused natural hazard (e.g., flood, earthquake), deterioration or incorrect operation
Out of Scope[10]	• URRW due to intentional malicious acts performed by an SCE Employee or Contractor • URRW due to an adversary gaining control of a high-hazard dam through physical access • URRW due to an adversary gaining control of a high-hazard dam through cyber access

C. Summary Results

Table I-2 summarizes the baseline risk analysis presented in his chapter, the controls and mitigations contemplated, and the portfolio results over the 2018 – 2023 period. Figure I-1 illustrates the composition of consequences within the baseline risk.

[10] The three scenarios that are classified as out of scope for this chapter are covered within the Employee, Contractor & Public Safety, Physical Security, and Cyber Attack chapters, respectively.

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Seismic Retrofit	x	x	x
C2	Dam Surface Protection	x	x	x
C3	Spillway Remediation and Improvement	x	x	x
C4	Low Level Outlet Improvement	x	x	x
C5	Seepage Mitigation	x	x	x
C6	Instrumentation and Communication Improvements	x	x	x
M1	Proactive Dam Removal		x	
M2	Relocation of Campgrounds			x
M3	Purchase of Private Residences			x
Mean (MARS)	*Cost Forecast ($ Million)*	$8	$33	$10
	Baseline Risk	0.77	0.77	0.77
	Risk Reduction (MRR)	0.18	0.21	0.19
	Remaining Risk	0.59	0.57	0.59
	Risk Spend Efficiency (RSE)	0.022	0.006	0.019
Tail Average (MARS)	*Cost Forecast ($ Million)*	$8	$33	$10
	Baseline Risk	2.47	2.47	2.47
	Risk Reduction (MRR)	0.58	0.65	0.60
	Remaining Risk	1.88	1.82	1.87
	Risk Spend Efficiency (RSE)	0.069	0.020	0.061

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

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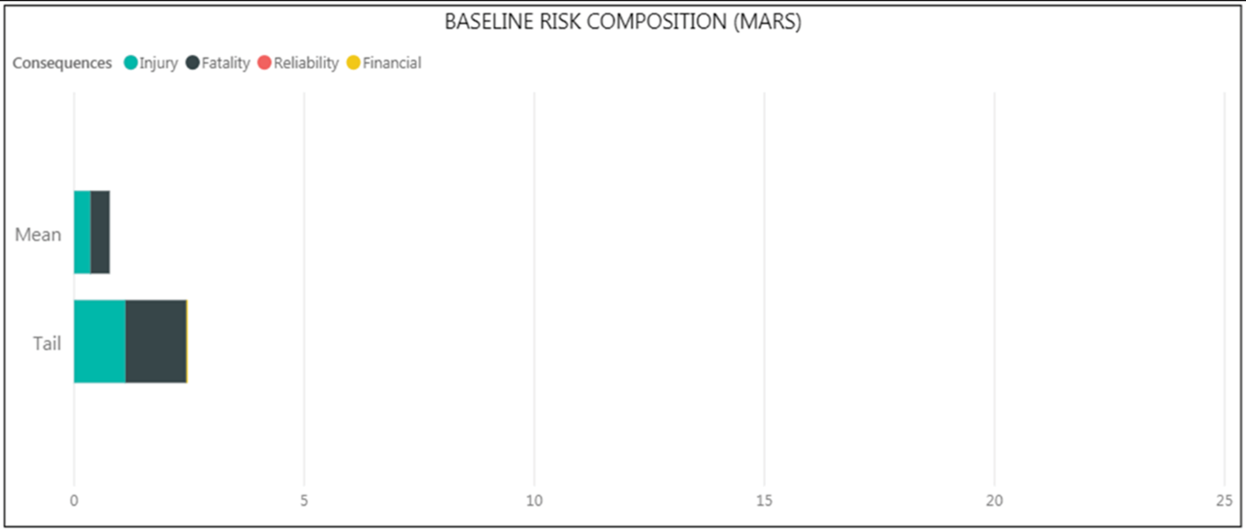
Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

Since 2008, SCE has maintained a Dam Safety Risk Assessment program, modeled after the "Risk Management – Best Practices and Risk Methodology," program established by the United States Bureau of Reclamation (USBR) in the mid-1990s.[11] The SCE Dam Safety Risk Assessment Program has been used to help understand, prioritize, and address potential dam safety issues across SCE's portfolio of dams.

The 28 high-hazard dams in scope for RAMP range in age from 32 to 112 years, with an average age of 90, and encompass a wide range of dam types, including:

- Earthfill – Balsam Meadow Dike, Bishop Intake 2 Dam, Lundy Lake Dam, Mammoth Pool Dam, Vermilion Valley Dam, Thompson Dam, and Wrigley Reservoir.
- Rockfill – Balsam Meadow Dam, Hillside Dam, Portal Forebay Dam, Rhinedollar Dam, Sabrina Lake Dam, Saddlebag Dam, and Tioga Lake Dam.
- Concrete Gravity – Big Creek Dam 7, Huntington Lake Dam 1, Huntington Lake Dam 2, Huntington Lake Dam 3, Kern River 1 Diversion, and Shaver Lake Dam.
- Concrete Arch – Big Creek Dam 4, Big Creek Dam 5, Big Creek Dam 6, Rush Meadows Dam, and Tioga Lake Auxiliary Dam.
- Concrete Multiple-Arch – Agnew Lake Dam, Florence Lake Dam, and Gem Lake Dam.

1. Federal Dam Safety Risk Management Practices

The USBR is responsible for overseeing the management of hundreds of high-hazard dams and dikes[12] that comprise a significant portion of the water resources in the western U.S. The USBR developed principles and methods for assessing and managing risk to prioritize investments in dams and make more effective use of their resources. The USBR framework has been updated, adopted and modified by the USBR and other federal dam owners, such as the U.S. Army Corps of Engineers (USACE). It forms the basis of the recently released Federal Emergency Management Agency (FEMA) Guidelines for Dam Safety Risk Management[13] and the

[11] The United States Bureau of Reclamation is a federal agency within the U.S. Department of the Interior. The Bureau of Reclamation oversees water resource management, specifically as it applies to the oversight and operation of the diversion, delivery, and storage projects that it has built throughout the western United States for irrigation, water supply, and attendant hydroelectric power generation.
[12] A long wall or embankment built to prevent flooding.
[13] "Federal Guidelines for Dam Safety Risk Management," Federal Emergency Management Agency, Report P-1025, January 2015.

FERC guidelines for Risk Informed Decision Making (RIDM),[14] which will be referred to as the Federal risk guidelines. Federal risk guidelines are based on two connected concepts:

- Tolerable Risk: A level of risk deemed acceptable by society in order that some particular benefit can be obtained, if that risk is being properly managed by the owner, and is reviewed and reduced as practicable; and,
- A risk has been appropriately reduced if it is As Low as Reasonably Practicable (ALARP).

The federal guidelines employ an f-N chart for evaluating risk at individual dams. The chart included in the FERC RIDM Guidelines is shown in Figure II-1. This chart plots the annual frequency of occurrence for a PFM (f) against the expected loss of life should the PFM occur (N). Four "zones" on the f-N chart are identified by the guidelines:

- Risks are unacceptable except in extraordinary circumstances. This zone is defined by the region where average annual life loss is greater than one fatality per 1,000 years, as indicated by reference line "A" in Figure II-1.
- Risks are generally tolerable, but ALARP considerations should be employed. This zone is defined by the region where average annual life loss is less than one fatality per 100,000 years, indicated by reference line "B" in Figure II-1.
- ALARP region – Risks are intolerable unless ALARP is satisfied. This zone is defined as the region between reference lines "A" and "B" in Figure II-1.
- Special considerations – Risks have extremely high consequences but low probability; a thorough review of the benefits and risk of the project is needed to determine tolerability. This zone is defined as the region bounded by expected fatalities greater than 1,000, but annual probability less than 1 in 1,000,000. This is indicated by reference line "C" in Figure II-1.

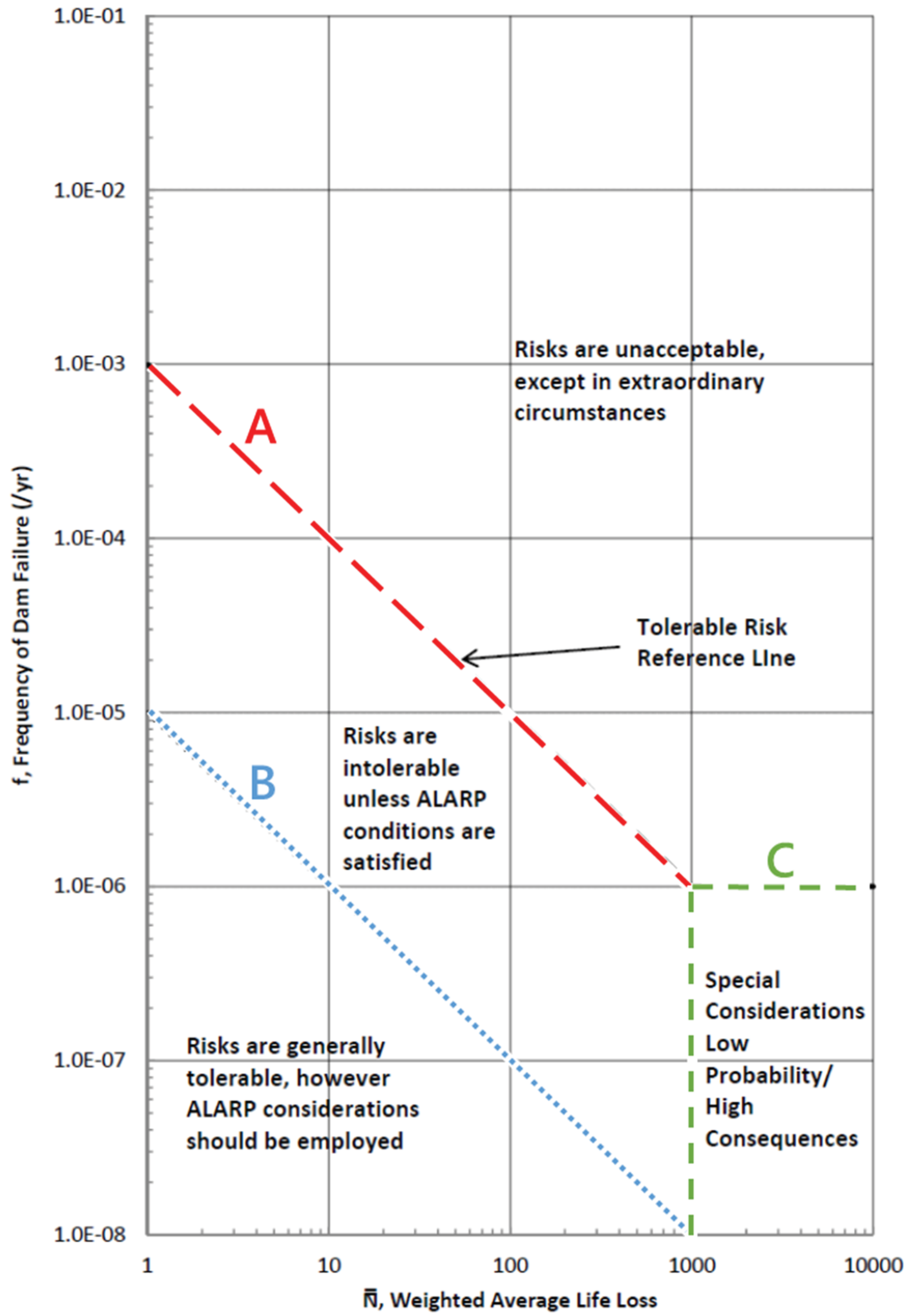
The FERC RIDM guidelines list the following criteria to evaluate if ALARP is satisfied:

- The cost-effectiveness of potential incremental risk reduction measures.
- The level of risk in relation to the tolerable risk reference lines.
- Disproportionality of the proposed investment relative to the benefits.
- Good Practice evidenced by compliance with FERC Engineering Guidelines or other industry-recognized standard or good practice.

[14] "Risk-Informed Decision Making (RIDM) Risk Guidelines for Dam Safety, Version 4.1," Federal Energy Regulatory Commission Division of Dam Safety and Inspections, March 2016.

- Societal concerns as revealed by consultation with the community and other stakeholders.
- Other factors, including duration of the risk, availability of risk reduction options, potential for creation of new risks, adequacy of the PFMA, consideration of standards, and benchmarking with other dam owners.

Figure II-1 – f-N Chart from FERC Risk-Informed Decision-Making Guidelines



Two types of risk analyses are used under FERC RIDM guidelines:

- Semi-Quantitative Risk Analyses (SQRA), where the likelihood and consequences for each PFM are classified into broad bins by teams of SMEs. The primary purpose of SQRA is to determine which PFMs are of most concern for a dam or portfolio of dams and require additional study and evaluation.
- Quantitative Risk Analyses (QRA), where additional field investigations, analyses and study are used to develop quantitative estimates of the probability of failure and the consequences of failure for the most critical PFM(s) of a dam or portfolio of dams. The primary purpose of QRA is to inform decision-making around dam safety investments, and typically involves analyzing both the risk under existing conditions and the risk under a set of proposed mitigations.

The FERC RIDM Guidelines, as well as those used by the USBR and USACE, emphasize that risk analyses are not intended to be used as the sole criteria for judging the safety of a dam. Rather, they are a component of a "Dam Safety Case" that presents the rationale for a proposed course of action to manage risk.

2. State Dam Safety Risk Management

The California DSOD does not have formal guidelines or criteria regarding dam safety risk. However, recent California law has directed DSOD to propose amendments to its dam safety inspection and re-evaluation protocols "to incorporate updated best practices, including risk management, to ensure public safety" by January 1, 2019.[15]

3. SCE Dam Safety Risk Management

SCE applies the principles outlined in the federal guidelines to managing risks identified for its dams. The defined inventory of dam risks is the set of PFMs developed through the FERC-required Potential Failure Modes Analysis (PFMA) process.[16] SCE has assigned likelihood and consequence categories to each of these PFMs through SQRA workshops involving SCE personnel, outside experts and regulators. The current categorization of dam risks resulting from these SQRAs is summarized in Figure II-2, which shows how the 230 PFMs are distributed across the likelihood and consequence categories. These results have been used by SCE to identify and prioritize dam safety projects, and serve as the foundation of the risk model presented in the chapter.

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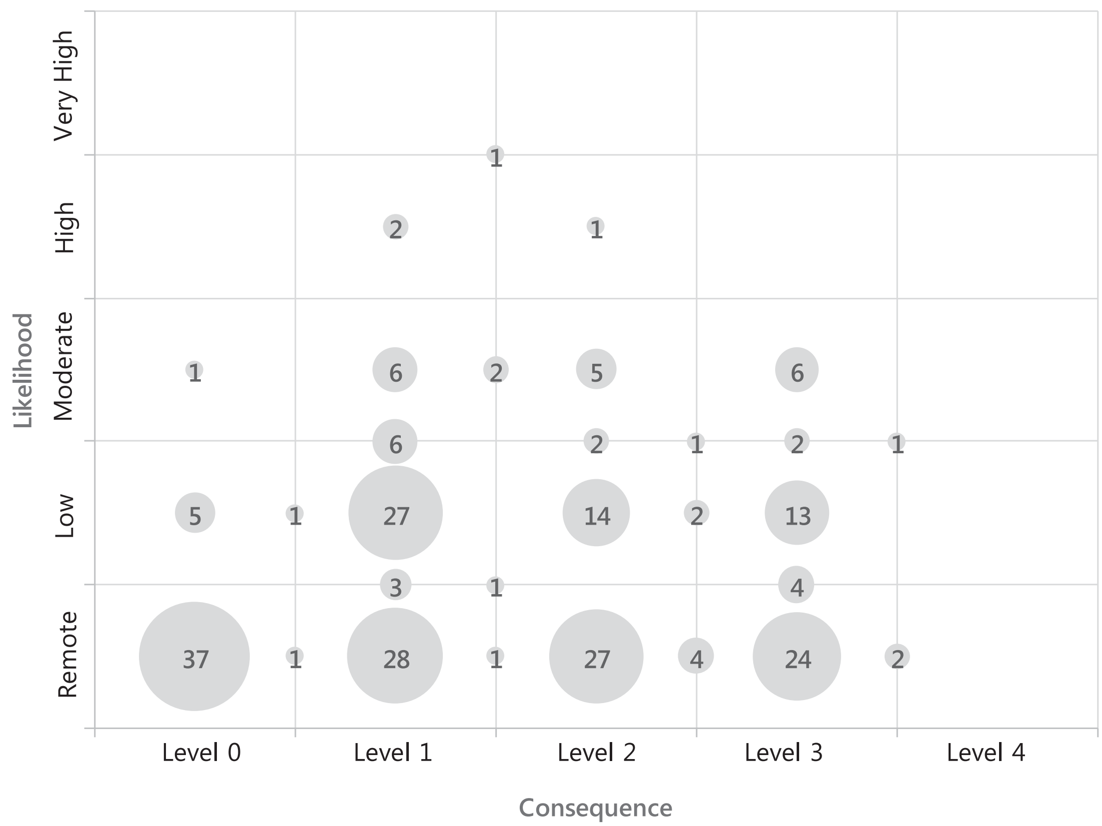
[15] "AB-1270 Dams and Reservoirs: Inspections and Reporting", February 26, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB1270

[16] Starting in 2002, FERC has required owners of high-hazard dams to perform PFMAs and update them every five years.

Figure II-2 – Risk Categorization of Potential Failure Modes for High-Hazard Dams

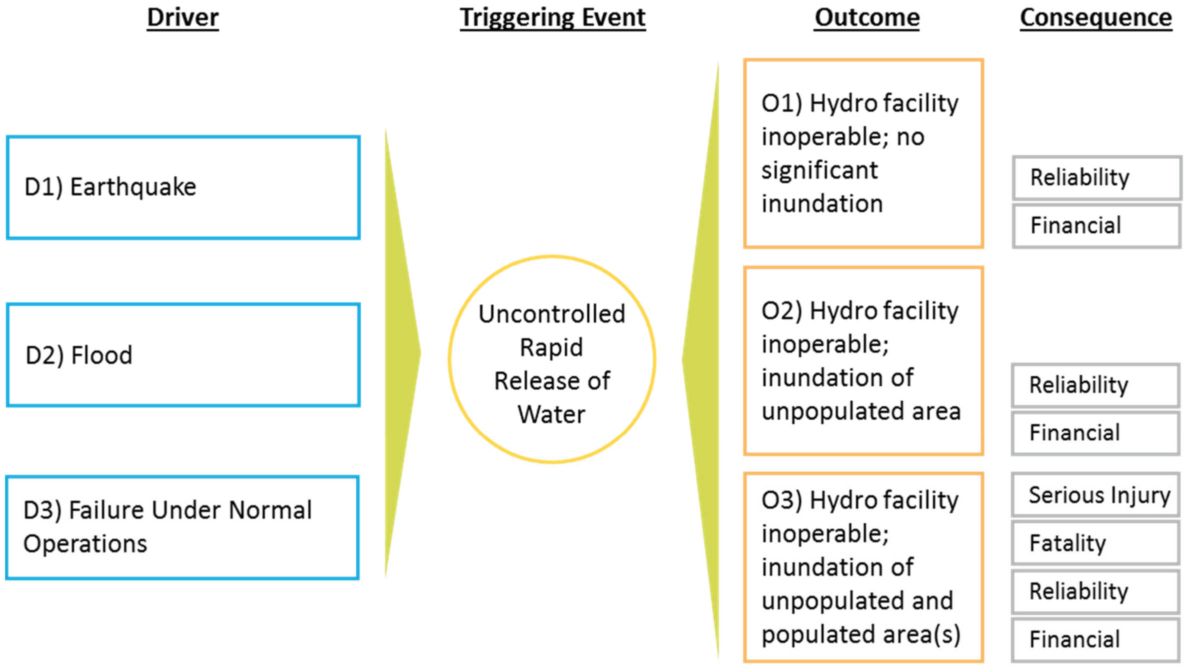


SCE has not previously performed QRA but is currently engaged in a pilot program under the FERC RIDM Guidelines (the second such project in the country) that will include a QRA for a single dam. This project is expected to conclude in 2019.

B. Risk Bowtie

SCE used the bowtie methodology, as shown in Figure II-3, to develop a quantitative risk model specific to SCE's high-hazard dams. This model uses a combination of SCE-specific data, industry data, and guidance from SCE dam safety experts, to gain a better understanding of the risk drivers and consequences for a dam failure. The bowtie presents the risk drivers, outcomes, and consequences; additional details can be found in the sections below.

Figure II-3 – Hydro Asset Safety Risk Bowtie



C. Driver Analysis

SCE has identified three drivers (Earthquake; Flood; Failure under Normal Operations) that could lead to the uncontrolled rapid release of water.

The risk model uses data based on the SCE Dam Safety Risk Register, which tracks the most current assessment of the likelihood and consequence of every identified PFM for each dam.[17] A total of 230 PFMs are associated with the 28 SCE dams evaluated for RAMP. Each PFM is mapped to one of the identified drivers (defined below); the estimated frequencies of all PFMs within a driver category are summed to produce the total driver frequency. Figure II-4 shows the projected 2018 frequency for each of these drivers.

[17] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

Figure II-4 – 2018 Projected Driver Frequency

Name	Freq	Frequency
D1 - Earthquake	0.0027	
D2 - Flood	0.0024	
D3 - Failure Under Normal Operations	0.0006	

1. D1 – Earthquake

Earthquakes must be taken into account for dams located in California. Several SCE dams, particularly those on the eastern slopes of the Sierra Nevada Mountains, are near known faults. For all dam sites, the possibility of activity on unidentified faults cannot be ruled out. The ground motions caused by earthquakes can negatively impact dams in a variety of ways:

- The material of embankment dams or their foundations may settle or slide such that the crest of the dam falls below the reservoir level. This allows water to spill over and erode the downstream material, leading to a complete breach. This nearly occurred at Lower Van Norman Dam when the 1971 San Fernando earthquake resulted in the loss of the upper 30 feet of the dam. The reservoir was only half-full at the time; had it been at full capacity, the resulting flood would likely have killed tens of thousands in the San Fernando Valley.
- Concrete dams may suffer significant cracking and loss of strength, compromising their ability to hold back the reservoir water. Movement of the rock foundations and abutments can also trigger a loss of support for the structure, leading to dam failure. While there are no recorded cases of concrete dams failing as a result of an earthquake, several have been damaged, such as Koyna Dam (1967) and Pacoima Dam (1971, 1994).

Assessing PFMs related to seismic events occurred in facilitated Risk Assessment Workshops that included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.[18] Risk Assessment Workshop participants considered all available information, including probabilistic seismic hazard evaluations for each dam site and seismic stability analyses.

A total of 61 PFMs, across the portfolio of high-hazard dams, were mapped to this driver. The combined annual probability[19] of occurrence of these PFMs is estimated at 0.26%,

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[18] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

[19] The likelihood of a given event's occurrence, which is expressed as a number between 1 and 0.

or 1 in 385 years. The seismic driver is attributable to 47% of the overall frequency of triggering events.

2. D2 – Flood

Flooding typically occurs because of heavy precipitation or snowmelt. Weather-related flooding events typically are easier to predict in the short term. SCE manages such events by using reservoir storage, passing water through spillways and outlets, and coordinating high-flow events with upstream and downstream dam operators. However, if water inflows exceed the capacity of the system, then the stability of the dam may be threatened.

- Water that goes over (i.e., overtops) an embankment dam will likely begin to erode and carry away the downstream material, which can progress to a complete breach. This occurred in the 1889 failure of South Fork Dam which claimed 2,209 lives in one of the worst disasters in U.S. history.[20]
- The rock foundations and abutments of concrete dams can also be vulnerable to erosion from extreme flood flows, leading to a loss of support for the dam and failure (Austin Dam 1911, Malpasset Dam 1959).

As indicated above, assessing PFMs related to seismic events occurred in facilitated Risk Assessment Workshops. These workshops included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD. [21] Risk Assessment Workshop participants considered all available information, including evaluating the probable maximum flood for each dam, and evaluating the stability of the dam under the resulting reservoir levels.

A total of 70 PFMs were mapped to this driver. The combined annual probability of occurrence of these PFMS is estimated at 0.24%, or 1 in 417. The flood driver is attributable to 44% of the overall frequency of triggering events.

3. D3 – Failure under Normal Operations

Dam failures have also been observed to occur in the absence of extreme loading events such as flood and seismic events. These types of failures are most common in dams with design or construction flaws, and generally occur within the first few years of operation. Some examples are the failures of St. Francis Dam (1928), Teton Dam (1976) and Camara Dam

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[20] "Case Study: South Fork Dam (Pennsylvania, 1889)" Lessons Learned from Dam Incidents and Failures, Association of State Dam Safety Officials. http://damfailures.org/case-study/south-fork-dam-pennsylvania-1889/

[21] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)*

(2004).[22] Though less common, dams that have functioned safely for decades may also fail due to degradation.

- Embankment dams can experience "piping" failures, where seepage through the dam begins to carry away the material. This creates an expanded cavity that could collapse, lowering the crest of the dam and allowing water to run over the top, thereby eroding the downstream material and progressing into a full breach.
- Concrete dams may experience a loss of strength due to "freeze-thaw" cycling[23] that eventually compromises the ability of the structure to retain the reservoir.
- Dam subsystems such as outlet pipes or spillway gates may also deteriorate over time, leading to failure and uncontrolled releases, such as the Folsom Dam (1995).
- Finally, failure to follow Station Orders and other operating procedures could potentially lead to a dangerous discharge of water. FERC determined that this led to a drowning death at Varick Dam (2010).[24]

In the Risk Assessment Workshops referenced above,[25] participants considered all available information, including design documents, surveillance and monitoring data, and previous repairs and improvements.

A total of 80 PFMs were mapped to this driver. The combined annual probability of occurrence of these PFMs is estimated at 0.05%, or 1 in 2,000. The failure under normal operations driver is attributable to 9% of the overall frequency of triggering events.

D. Triggering Event – Uncontrolled Rapid Release of Water

SCE defines the Triggering Event as the Uncontrolled Rapid Release of Water (URRW) from a Hydro High-Hazard Dam. This definition has been used by SCE's Dam & Public Safety department since 2008 and is consistent with the Federal Guidelines for Dam Safety Glossary of Terms,[26] which defines dam failure as "characterized by the sudden, rapid, and uncontrolled

[22] The owners of these dams were the City of Los Angeles, The United States Bureau of Reclamation (USBR), and Brazil.

[23] A process where water permeates tiny cavities in concrete and freezes. Since ice occupies approximately 9% more volume than the same amount of liquid water, this stresses the concrete and may result in cracking and expansion of the cavities. When thawing occurs, liquid water fills the expanded cavity and the process repeats.

[24] "Erie Boulevard Hydroelectric, L.P., Order Approving Stipulation and Consent Agreement," Federal Energy Regulatory Commission, Docket No. IN13-12-000. January 15, 2014.

[25] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)*

[26] "Federal Guidelines for Dam Safety Glossary of Terms." Federal Emergency Management Agency, Report 148, April 2004.

release of impounded water." While any type of damage or malfunction that prevents a hydroelectric high-hazard dam from functioning as intended can be considered a failure, SCE has identified uncontrolled, rapidly-occurring discharges as the greatest potential threat to the safety of the downstream population.[27]

E. Outcomes & Consequences

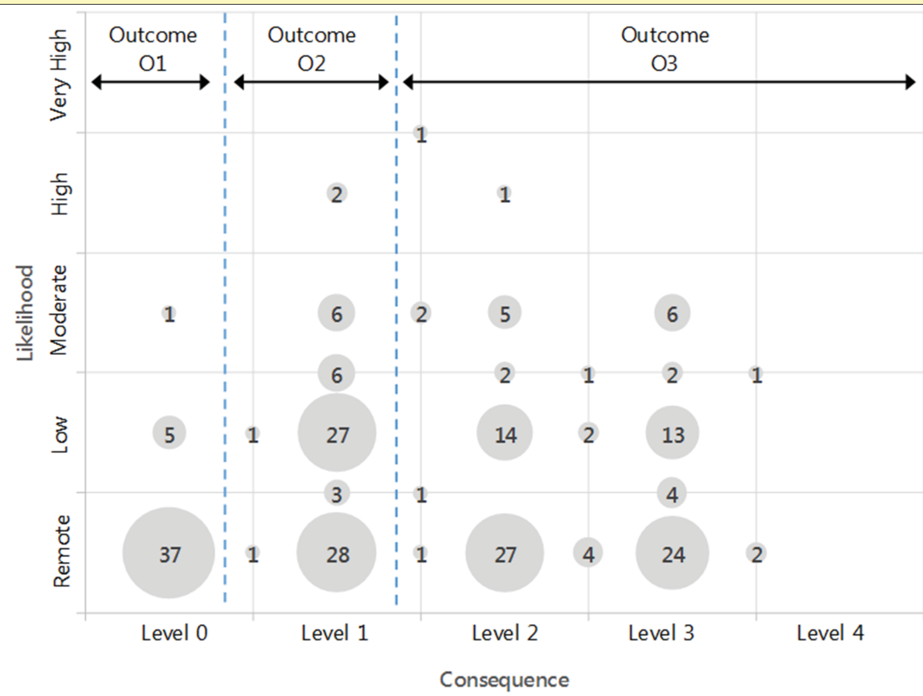
SCE has identified three potential outcomes should URRW occur. Figure II-5 depicts the estimated likelihood of the three outcomes.

Figure II-5 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Hydro Facility Inoperable; No Significant Inundation	2.0 %	
O2 - Hydro Facility Inoperable; Inundation of Unpopulated Area	33.4 %	
O3 - Hydro Facility Inoperable; Inundation of Unpopulated & Populated Area(s)	64.6 %	

Each of the 230 PFMs evaluated in the SCE portfolio is uniquely mapped to one of the three outcomes based on severity as shown in Figure II-6.

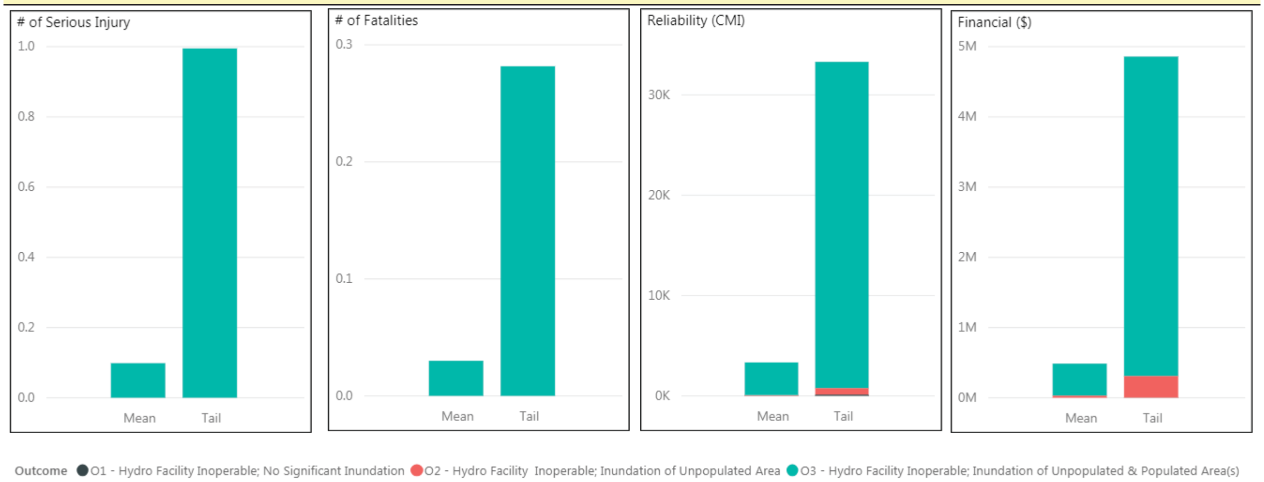
Figure II-6 – Mapping of Potential Failure Modes to Outcomes



[27] Controlled discharges afford an opportunity for planning and communication efforts to mitigate the impacts, while a slowly occurring discharge allows for evacuating potentially impacted areas. Hydro Asset failures resulting in URRW have been the focus of SCE's previous risk assessment activities for dams, and will remain the focus in this RAMP chapter.

Figure II-7 illustrates the composition of the modeled baseline risk in terms of each consequence dimension. The sections that follow describe the inputs used to derive these risks.

Figure II-7 – Modeled Baseline Risk Composition by Consequence (Natural Units)



1. O1 – Hydro Facility Inoperable; No Significant Inundation

This outcome is occurs when a dam failure causes URRW, but it does not result in significant downstream inundation (i.e., the water is contained within the normal banks of the stream). If the dam is directly connected to a hydroelectric plant, that plant will be inoperable. If the dam is a storage reservoir, that storage capacity will be unavailable. Hydro facilities will remain unavailable until the damage is repaired. Approval from federal and/or state regulators will also be required to resume operation.

Of the 230 assessed PFMs, 43 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 2% of the overall Triggering Event frequency.[28]

Potential consequences from O1 are summarized on an annualized basis in Table II-1. Reliability consequences are associated with localized areas served by hydroelectric plants that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power. For O1, the estimate of annual impacts is 13 customer minutes of interruption (CMI) and $163 of financial harm on a mean basis, and 132 CMI and $1,632 of financial harm and on a tail-average basis.

[28] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

Table II-1 – Outcome 1 (Hydro Facility Inoperable): Consequence Details

Outcome 1		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*			SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants and averaged over all PFMs mapped to O1.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. Impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O1.
Model Outputs	NU - Mean			13 CMI	$163
	NU - Tail Avg			132 CMI	$1,632

2. O2 – Hydro Facility Inoperable; Inundation of Unpopulated Area

This outcome occurs when a dam failure causes URRW, resulting in loss of operability of the associated hydro assets, and the inundation of unpopulated downstream areas. For the dams considered in RAMP, these areas would generally be forested areas that people do not regularly occupy or travel.

Of the 230 assessed PFMs, 74 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 33% of the overall Triggering Event frequency.

Potential consequences from O2 are summarized on an annualized basis in Table II-2. Reliability consequences are associated with localized areas served by hydroelectric plants that are periodically “islanded” from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation. For O2, the estimate of annual impacts is 65 customer minutes of interruption (CMI) and $30,930 of financial harm on a mean basis, and 648 CMI and $309,299 of financial harm on a tail-average basis.

Table II-2 – Outcome 2 (Inundation of Unpopulated Areas): Consequence Details

Outcome 2		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants and averaged over all PFMs mapped to O2.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. SCE used financial impact scoring performed by Dam Safety engineers in 2016 to estimate the costs due to inundation for failure of each dam. The combined impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O2.
Model Outputs	NU - Mean			65 CMI	$30,930
	NU - Tail Avg			648 CMI	$309,299

3. O3 – Hydro Facility Inoperable; Inundation of Unpopulated and Populated Area(s)

The worst-case outcome considered is a dam failure resulting in URRW that inundates a populated area. This impact is in addition to the inundation of unpopulated areas and loss of operability for the associated hydro facilities.

Of the 230 assessed PFMs, 113 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 65% of the overall Triggering Event frequency.

Potential consequences from O3 are summarized on an annualized basis in Table II-3. Safety consequences, including serious injuries and fatalities are associated with pedestrians, occupied vehicles, or occupied structures caught by the released water. Reliability consequences are associated with disruption of service to localized areas due to direct damage to the electrical system, as well as periodic disruptions to areas served by hydroelectric plants that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation. For O3, the estimate of annual impacts is 0.10 serious injuries, 0.03 fatalities, 3,252 customer minutes of interruption (CMI) and $454,867 of financial harm on a mean basis, and 1.00 serious injuries, 0.28 fatalities, 32,523 CMI and $4,548,672 of financial harm on a tail-average basis.

Table II-3 – Outcome 3 (Inundation of Populated Areas): Consequence Details

Outcome 3		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE used internal estimates for potential life safety impacts of each PFM developed during Dam Safety Risk Assessments (2009-2018), which are informed by inundation mapping and consequence evaluations. Serious Injuries were estimated for each PFM by scaling Fatalities based on draft FEMA guidance document. Consequences were averaged over all PFMs mapped to O3.	SCE used internal estimates for Fatalities associated with each PFM developed during Dam Safety Risk Assessments (2009-2018), which are informed by inundation mapping and consequence evaluations. Consequences were averaged over all PFMs mapped to O3.	SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants. SCE identified areas where URRW could impact electrical assets and estimated impact of a one week outage. Impacts were associated to PFMs for dams capable of causing outages. Combined reliability impacts were averaged over all PFMs mapped to O3.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. SCE used financial impact scoring performed by Dam Safety engineers in 2016 to estimate the costs due to inundation for failure of each dam. The combined impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O3.
Model Outputs	NU - Mean	0.10	0.03	3,252 CMI	$454,867
	NU - Tail Avg	1.00	0.28	32,523 CMI	$4,548,672

III. Compliance & Controls

SCE has existing programs and processes in place that serve to reduce the likelihood of the risk materializing, or the impact level of a risk event should it occur. All of these activities are summarized in Table III-1 and discussed in more detail in the sections that follow.

As discussed in Section I, compliance activities (CM1-CM4) are required to adhere to laws and regulations governing dam safety. Electing not to perform this work for a dam would likely result in an order from the FERC to cease generation, and possibly revocation of the associated FERC license (as was recently issued to Boyce Hydro in 2018).[29] Similarly, DSOD has the authority to impose reservoir restrictions and to revoke the certificate of approval required to operate a dam in California if it determines that there is a danger to life and property. Consequently, SCE did not consider a "baseline" risk that lacked these compliance activities and accordingly did not risk-score compliance activities.

Hydro Capital Maintenance Refurbishment and/or Replacement activities (C1-C6) are controls consisting of capital investments necessary for maintaining dam infrastructure and equipment. Infrastructure work includes projects such as dam improvements needed to address identified areas of concern. SCE considered all work forecast to occur in 2018-2023 for the 28 high-hazard dams and evaluated the work's impact on mitigating the RAMP drivers, outcomes and consequences.[30,31]

[29] "Boyce Hydro Power, LLC; Order Proposing Revocation of License." Federal Energy Regulatory Commission, Document 83 FR 8253. February 26, 2018.

[30] The process used to forecast Hydro capital expenditures begins with staff identifying equipment needing capital replacement or refurbishment, safety concerns or regulatory compliance issues requiring plant additions or modifications (which includes Hydro relicensing), and other site modifications or improvements needed to address operations or maintenance needs.

[31] The risk-reduction achieved by the controls was modeled using input from Subject Matter Experts (SMEs). Please refer to WP Ch. 8, pp. 8.4 – 8.13 *(RAMP Mitigation Reduction Workpaper)* and the supplemental worksheets in its electronic version for details on modeling of controls, and WP Ch. 8, p. 8.14 (Subject Matter Expert Judgement) for qualifications of the participating SMEs.

Table III-1 – Compliance and Control Activities

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Reduced	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Hydro Operations	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.2
CM2	Hydro Maintenance	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.3
CM3	Dam Safety Program	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.2
CM4	External Inspections	Not Modeled	Not Modeled	Not Modeled	$ -	$ 0.7
C1	Seismic Retrofit	D1	-	-	$ -	$ -
C2	Dam Surface Protection	D3	-	-	$ 5.3	$ -
C3	Spillway Remediation and Improvement	D2	-	-	$ 0.3	$ -
C4	Low Level Outlet Improvements	-	O2, O3	S-I, S-F, F	$ -	$ -
C5	Seepage Mitigation	D3	-	-	$ -	$ -
C6	Instrumentation / Communication Enhancements	-	O3	S-I, S-F	$ 0.7	$ -

Consequences Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Hydro Operations

SCE is required to operate its hydroelectric facilities in a safe manner. This includes maintaining situational awareness of the system through inspections and instrumentation, regulating the water flows and reservoir levels, and operating hydroelectric generating units.

SCE's trained hydro operations and maintenance personnel routinely observe dams. These personnel are stationed in the watersheds where the SCE dams are located. During regular visits to the dams, these personnel perform visual observations of the dams, collect monitoring data, and report any changed or unusual conditions that could potentially impact dam safety or SCE's ability to operate the facility's spillways and outlet structures in a safe manner.

Operations personnel regulate water flows to help ensure efficient use of water and maximum generation from resources. This activity includes:

- Regularly inspecting the reservoir facilities;
- Making gate changes to regulate water releases;
- Cleaning the grids at flowline entrances; and
- Removing debris from in and around flowlines, flumes, penstocks and other typical Hydro waterways.

Station Orders are created to help ensure that controlled releases are performed safely. All station personnel are required to follow station orders.

Dispatching work includes directing all O&M activities associated with the powerhouses in the Big Creek and Bishop Creek/Mono Basin areas, and the associated transmission and distribution facilities. The dispatching function is critical to successfully operating these facilities. The Big Creek Control center contains all the supervisory control equipment for the Big Creek facilities, while the Bishop Control substation contains all the supervisory control equipment for the Bishop Creek, Mono Basin, and Kern River facilities.

Unmanned East End and Kaweah facilities have alarms that notify the Bishop Control substation of unusual events through a dial-up system. This 24-hour surveillance of the operating equipment from a central point helps maintain system integrity and operational effectiveness.

B. CM2 – Hydro Maintenance

SCE is required to maintain its hydroelectric facilities, including dams, in a safe operating condition.

This activity includes planning and scheduling equipment maintenance activities at reservoirs, dams, canals, flumes, and other appurtenant hydraulic structures to comply with state and federal regulatory requirements. The activity also encompasses condition analysis, engineering recommendations, and mandated reports. SCE is required to test, inspect, and report to make sure that the physical condition of facilities and equipment is safe for continued operation, through efforts such as:

- Technical inspection
- Electrical and mechanical engineering
- Civil, structural, and geotechnical engineering
- Construction management and cost engineering
- Performance engineering and testing
- Supervising repairs at Hydro production facilities, structures, and equipment,
- Providing engineering support needed to perform tests and inspections, and prepare reports.
- Applying concrete gunite[32] to repair aged and weather-damaged surfaces of dams and intakes;
- Repacking joints and repairing leaks in steel penstock pipes and flumes;
- Maintaining water-diverting equipment such as valves and spillways; and

[32] "Gunite" is a mixture of cement, sand, and water applied through a high-pressure hose. It produces a dense, hard layer of concrete, and can be used for lining tunnels or making structural repairs.

- Repairing wood-frame structures appurtenant to Hydro facilities, such as flowline trestles, snow shelter survival cabins, gatehouses, and hydraulic equipment shelters.

C. CM3 – Dam Safety Program

SCE is required to maintain a dam safety program to help ensure that its hydroelectric facilities operate safely.

SCE's Dam Safety Program (DSP) aims to protect life, property, and the environment by making sure that all dams are designed, constructed, operated, and maintained as safely and as effectively as reasonably possible. To accomplish this, SCE must continually inspect, evaluate, and document the design, construction, operation, maintenance, rehabilitation, and emergency preparedness of SCE and key downstream stakeholders. SCE also needs to archive documents concerning the inspections and histories of dams, and the training records for personnel who inspect, evaluate, operate, and maintain them.

These activities are governed by SCE's Owner's Dam Safety Program (ODSP). The ODSP is a FERC-required document that established roles and responsibilities regarding dam safety at SCE, up to and including the President and CEO. SCE's Dam & Public Safety (D&PS) Group, led by the Chief Dam Safety Engineer (CDSE) is responsible for overseeing the operations and strategies that help ensure that SCE's hydro generating facilities operate safely and reliably. Responsibilities include:

- Conducting inspections of dams and supporting inspections by FERC, DSOD and the Part 12D Independent Consultants;
- Evaluating field observations and data collected under the Surveillance and Monitoring Program for each dam;
- Identifying and prioritizing key issues for dams through the Risk Assessment Program, and helping ensure that all data and records pertaining to dam safety are appropriately maintained;
- Providing technical leadership and support to help ensure compliance with the FERC and the California DSOD regulations; and
- Helping ensure that Emergency Action Plans (EAPs) for high-hazard dams are supported by appropriate inundation mapping[33] and analysis of potential failure scenarios. Also, assisting in EAP training and exercises.

[33] "Inundation mapping" generally refers to a map that delineates the area that would be flooded by a particular flood event. It includes the ground surfaces downstream of a dam, showing the probable encroachment by water released because of: (a) failure of a dam, or (b) abnormal flood flows released through a dam's spillway and/or other appurtenant pathways for the water.

The expectations of the Dam Safety Program are prescribed by FERC, which requires Owners to undergo an external audit of their ODSP every five years. SCE also goes beyond FERC's expectations for the ODSP by employing an independent panel of experts titled the Dam Safety Advisory Board (DSAB) to review the Dam Safety Program on an annual basis and to advise on dam safety issues as requested. In addition, for complicated dam safety issues, a Board of Consultants may be convened to opine and advise on issues, and help guide SCE's actions to address those issues.

D. CM4 – External Inspections

SCE's dams are routinely inspected and evaluated by external parties. Inspections are performed by:

1. FERC Division of Dam Safety and Inspections (FERC D2SI). As the federal agency responsible for the safety of hydroelectric projects located on federal lands, FERC D2SI inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure the inspector can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspector may have. Following the inspection, FERC issues a letter documenting the inspection findings, which may include recommending specific repairs, actions or studies. SCE is required by FERC to file a plan and provide a schedule to address these recommendations.
2. California Department of Water Resources, Division of Safety of Dams (DSOD). As the state agency responsible for maintaining the safety of dams in California, DSOD inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure they can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspectors may have. Following the inspection, DSOD issues a report that may include recommendations for specific repairs, actions or studies.
3. Part 12 Independent Consultants. Since 1965, FERC has required, under 18 CFR Part 12, that owners of dams designated as high-hazard, or that meet specified criteria for size, must be evaluated by an Independent Consultant every five years. FERC reviews the credentials and approves every Independent Consultant. The Independent Consultant physically inspects the condition of the dam, and comprehensively evaluates the operating procedures, supporting analyses, and other documentation. The Independent consultant also reviews the Potential Failure Modes Analysis to re-evaluate existing PFMs and identify whether any new PFMs are

needed. The Independent Consultant provides written findings to FERC. This includes stating whether the dam is safe for continued operation, and listing recommendations for repairs, actions or studies. SCE must file a plan and provide a schedule to FERC to address these recommendations.

4. Board of Consultants. FERC has the authority to require that a dam owner retain a Board of Consultants to regularly inspect a specific dam. Currently, only Vermilion Valley Dam (SCE's largest embankment dam) has an established Board of Consultants, who perform annual inspections and issue a report on their findings. While not required by FERC, the design engineers of Vermillion Valley Dam have emphasized that the continued safe operation of the dam depends upon the performance (as assessed by the Board of Consultants) of the dam's complicated drainage system.

E. C1 – Seismic Retrofit

SCE retrofits its dams to increase their capability to withstand seismic loads. SCE performs this activity when it identifies deterioration of the structure, a deficiency in the original design, or an increase in the estimated seismic loads that the dam must withstand.

This work may include rehabilitating and/or replacing concrete, re-compacting and/or replacing embankment materials, installing post-tensioned anchors, and constructing reinforcing elements such as steel braces, concrete buttresses or earthen berms. Some of SCE's dams currently operate under restricted intended reservoir levels, due to potential vulnerability to seismic loading. At these dams, seismic retrofit work may also include making modifications to enhance SCE's ability to maintain these restrictions. Specifically, the work can include lowering the spillway elevation or improving the capacity and/or reliability of the low level outlet works (further discussed in below).

1. Drivers Impacted

This control impacts D1 (Earthquake) by reducing the occurrence of failures due to seismic loading. Please note that this control provides benefit not by reducing the frequency of actual seismic events (which, of course, are outside of SCE's control), but by reducing the Triggered Event Frequency number that springs from seismic events.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

F. C2 – Dam Surface Protection

SCE, along with the previous owners of the SCE dams, have consistently attempted to protect these structures against deterioration by waterproofing the upstream surfaces with methods such as grouting or polysulfide coatings. Since 2006, SCE has found that installing a geomembrane liner system significantly reduces leakage in both concrete and embankment dams. These liners have been installed at seven dams. Installation at an eighth dam is in progress. While many of the high-priority dams have been lined, SCE believes two to three more dams may be candidates for this system in 2019-2023.

1. Drivers Impacted

This control impacts D3 (Failure under Normal Operations) by reducing the leakage through the dam, reducing deterioration at concrete structures, and inhibiting flows through embankment dams that could contribute to internal erosion failures.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

G. C3 – Spillway Remediation and Improvement

SCE repairs and improves the spillways at its dams. This work can include refurbishing deteriorated concrete, installing or improving protective measures (such as water-stops between concrete slabs or drains beneath spillway chutes), rehabilitating or improving spillway gate structures, expanding the spillway or armoring embankment dams to allow them to withstand overtopping of water.

1. Drivers Impacted

This control impacts D2 (Flood) by enhancing the capacity and reliability of dams to safely pass inflows from extreme floods.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

H. C4 – Low Level Outlet (LLO) Improvements

SCE performs LLO repair and improvements for dams. LLOs are systems that can be used to lower the reservoir level of a dam in a controlled manner. In addition to managing water levels during normal operations, LLOs can be used in an emergency to empty the reservoir to prevent or reduce the consequences of dam failure. DSOD has specific requirements regarding the capacity and testing of these systems.

This work can include repairing or replacing valves, gates, gate operators, or constructing a replacement LLO system if the original systems is too costly or difficult to repair.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. Although it is possible that low-level outlets could be utilized to drain a reservoir to prevent a slow-developing failure (occurring over multiple days), there was not sufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety and Financial consequences of O2 (Hydro Facility Inoperable; Inundation of Unpopulated Areas) and O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas) by allowing SCE to partially drain reservoirs in a controlled fashion prior to dam failure to reduce the volume of water in the resulting URRW.

I. C5 – Seepage Mitigation

SCE performs seepage mitigations to reduce the likelihood of initiation and progression of internal erosion in embankment dams. This work can include constructing or rehabilitating drains to reduce seepage, constructing filters to mitigate erosion, and filling sinkholes or joints in the foundation on the upstream side of the dam. Please note that in some cases, reducing seepage from the dam could negatively impact downstream wetlands areas. As a result, SCE may be required under the Clean Water Act to perform compensatory mitigation, which could include restoring a previously existing wetland, enhancing/preserving an existing wetland, or establishing a new wetland.[34] This requirement can be met by purchasing credits from an approved "mitigation bank" as proposed by the US Army Corps of Engineers for their Sacramento River Seepage Mitigation Project.[35] Depending on the circumstances, this requirement could represent a significant portion of the costs.

1. Drivers Impacted

This control impacts Driver D3 (Failure under Normal Operations) by reducing the probability that identified PFMs related to internal erosion will progress to failure.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

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[34] "Compensatory Mitigation for Losses of Aquatic Resources; Final Rule." Department of Defense 33 CFR Part 325 and 332, Environmental Protection Agency 40 CFR Part 230. April 10, 2008, *available at* https://www.epa.gov/sites/production/files/2015-03/documents/40_cfr_part_230.pdf

[35] "Sacramento River Seepage Mitigation Project", US Army Corps of Engineers website, *available at* http://www.spk.usace.army.mil/Media/Regulatory-Public-Notices/Article/1531315/spk-2018-00139-sacramento-river-seepage-mitigation-project-yolo-county-ca/

J. C6 – Instrumentation and Communication Improvements

Many SCE dams are in remote locations, and none have permanent on-site dam tenders.[36] However, SCE uses instrumentation to monitor the condition of these dams at centralized Hydro Control Rooms, where an operator is present 24 hours a day. SCE performs work to maintain and improve the capability and reliability of dam instrumentation. This work can consist of repairing, replacing, or installing instruments. Such instruments include reservoir level indicators, flow measurement devices, piezometers[37] and surveillance cameras. The work also encompasses repairing and/or improving the systems that transmit the instrument readings via fiber, radio, and/or satellite to Hydro Control Rooms.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. It is possible that detecting potential failure conditions could allow SCE to intervene to prevent a dam failure from occurring. However, after reasonable inquiry there was insufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety consequences of O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas).

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[36] A “dam tender” is the person responsible for daily or routinely operating and maintaining a dam and its appurtenant structures. The dam tender often resides at or near the dam.

[37] Generally speaking, a “piezometer” is an instrument for measuring the pressure of a liquid or gas, or something related to pressure (such as the compressibility of liquid). Piezometers are often placed in boreholes to monitor the pressure or depth of groundwater.

IV. Mitigations

In addition to the controls describe above, SCE has identified additional risk mitigations that could be performed over the 2018-2023 RAMP period.[38] These are shown in Table IV-1.

Table IV-1 – Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Reduced	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Proactive Dam Removal	All	-	-		x	
M2	Relocation of campgrounds	-	O3	S-I, S-F			x
M3	Purchase of Private Residences	-	O3	S-I, S-F			x

Consequences Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period.

A. M1 – Proactive Dam Removal

The risk of failure for a dam can never be reduced to zero – unless the dam is removed. Currently, when SCE is considering whether to make significant investment in a given dam, decommissioning is considered as an alternative. SCE could, hypothetically, alter its strategy to consider proactively decommissioning dams to reduce risk. Dam removal is an extensive process that involves: (a) developing a detailed construction plan for safely removing the asset; (b) obtaining all necessary regulatory approvals; (c) performing the work while taking appropriate measures to protect the environment and appropriately dispose of the removed material; (d) remediating the area to a “natural” state in consultation with the appropriate state and federal agencies; and (e) mitigating the impact of dam removal on the downstream community in consultation with all public and private stakeholders.

1. Drivers Impacted

This mitigation impacts D1 (Earthquake), D2 (Flood), and D3 (Failure under Normal Operation) by eliminating all PFMs associated with the removed dams.

2. Outcomes and Consequences Impacted

This mitigation is not considered to impact outcomes and consequences.

[38] The risk-reduction achieved by the mitigations was modeled using input from Subject Matter Experts (SMEs). Please refer to WP Ch. 8, pp. 8.4 – 8.13 *(RAMP Mitigation Reduction Workpaper)* and the supplemental worksheets in its electronic version for details on modeling of controls, and WP Ch. 8, p. 8.14 *(Subject Matter Expert Qualifications)* for qualifications of the participating SMEs.

B. M2 – Relocation of Campgrounds

When many of SCE dams were constructed, the downstream areas were relatively undeveloped. The encroachment of inhabited areas into potential inundation zones is an issue many dam owners face. At many SCE dams, a large portion of the population at risk in a dam failure are located in campgrounds. Relocating these sites could potentially reduce risk.

SCE may be able to accomplish this mitigation by working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones. While this work has not been performed before by SCE, there are examples of campgrounds relocated out of flood plains that may serve as a precedent.[39]

1. Drivers Impacted

This mitigation is not considered to impact drivers.

2. Outcomes and Consequences Impacted

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas), as it effectively reduces the populated area that could potentially be inundated by a dam failure.

C. M3 – Purchase of Private Residences

Similar to relocating campgrounds, purchasing private residences in the potential inundation zone could reduce the consequences of a dam failure. BC Hydro recently used this strategy to reduce risk for a dam identified as vulnerable to failure if a large earthquake occurs.[40,41]

1. Drivers Impacted

This mitigation is not considered to impact drivers.

2. Outcomes and Consequences Impacted

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas). The mitigation would reduce the population that could be inundated by a dam failure.

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[39] "Tucannon Lakes and Floodplain Reconfiguration," Washington Department of Fish & Wildlife, *available at* https://wdfw.wa.gov/lands/wildlife_areas/wt_wooten/floodplain_management/TucannonWootenFactSheet_2015_April.pdf

[40] "BC Hydro Buys Out Properties Below Jordan River Dam." CBC News, May 18, 2016, *available at* https://www.cbc.ca/news/canada/british-columbia/b-c-hydro-jordan-river-1.3585351

[41] "Seismic Hazard at Jordan River", BC Hydro website, *available at* https://www.bchydro.com/energy-in-bc/operations/dam-safety/seismic-hazards/jordan-river-options.html

V. Proposed Plan

SCE has evaluated the mitigations and controls in Sections III and IV and developed a proposed plan of risk-reduction activities to pursue, summarized in Table V-1, below.

Table V-1 – Proposed Plan

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0152	0.0021	0.0496	0.0067
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0013
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.4235	0.0353	1.3884	0.1157
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0150	0.0011	0.0492	0.0037
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0356	0.0034	0.1173	0.0112
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.6020	0.0937	1.8679	0.2909
			Total - Proposed Plan	**$ 50.2**	**$ -**	**1.0915**	**0.0217**	**3.4732**	**0.0692**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

SCE's proposed plan includes capital maintenance and refurbishment projects including C1 (Seismic Retrofit), C2 (Dam Surface Protection), C3 (Spillway Remediation and Improvement), C4 (Low Level Outlet Improvements), C5 (Seepage Mitigation), and C6 (Instrumentation and Communication Improvements). This work is a continuation of SCE's efforts to responsibly manage the risk associated with its high-hazard dams.

B. Execution Feasibility

Although SCE expects to be able to execute the amount of work contemplated in this Proposed Plan, executing on the proposed capital projects can be impacted by the need to obtain approvals, given the large number of agencies involved. A project may require approvals from FERC, DSOD, U.S. Forest Service, California Department of Fish & Wildlife, California Water Quality Board, regional water quality control boards, California State Historic Preservation Officer, local air quality districts, and/or others. Some of these approvers will have competing requirements and interests.

Another factor that impacts the execution schedule of the projects is the short construction window for many dams. Most construction projects for dams at higher elevations cannot begin until June or July, due to snow conditions. The end of the working season for many sites is typically early November, but early storms can shut down projects as early as October. This can cause projects to extend by one to two years.

C. Affordability

SCE believes the proposed controls are an appropriate investment in maintaining the safety of its dams, many of which have been in operation since the early 20th century. While the baseline risk is the lowest among the nine risks scored for RAMP, the proposed portfolio is estimated to reduce this risk by approximately 23%. This 23% figure is incremental to the risk already reduced through required compliance activities.

This Proposed Plan, especially C3 (Spillway Remediation and Improvement) and C5 (Seepage Mitigation), will address the top risks within SCE's portfolio of dams identified through this RAMP analysis, as well as SCE's existing Dam Safety Risk Assessment Program. By improving the instrumentation and communication systems, including deploying surveillance cameras in C6 (Instrumentation and Communication Improvements), we expect to significantly improve our ability to identify potential dam failures and, where necessary, activate Emergency Activation Plans to notify downstream stakeholders. When the USBR analyzed historical dam failures, the USBR concluded that adequate warnings reduced fatalities by more than ten times compared to cases where no warning was provided.[42]

Some of the proposed controls have relatively low RSE, but are still recommended as they provide other benefits. While C2 (Dam Surface Protection) does not significantly reduce risk, installing these liners slows deterioration and extends the useful life of the dams. Similarly, C4 (Low Level Outlet Improvements) enhances SCEs ability to manage water for normal operation and maintenance activities.

D. Other Considerations

Projects that require draining or substantially lowering the reservoir levels can face challenges with competing water management needs. In high runoff years, it may be difficult to safely release or store the water elsewhere. In low water years, draining a reservoir may negatively impact SCE's ability to meet its obligations to other water users and meet minimum flows required to protect aquatic species and riparian habitats.

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[42] RCEM – Reclamation Consequence Estimating Methodology, Interim Guidelines for Estimating Life Loss for Dam Safety Risk Analysis." U.S. Bureau of Reclamation, July 2015, *available at* http://www.usbr.gov/ssle/damsafety/documents/RCEM-Methodology.pdf

VI. Alternative Plan #1

SCE has evaluated the mitigations and controls in Sections III and IV and developed an alternative plan for reducing risk, as summarized in Table VI-1.

Table VI-1 – Alternative Mitigation Plan #1

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0147	0.0020	0.0472	0.0064
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0012
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.3353	0.0279	1.0691	0.0891
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0150	0.0011	0.0500	0.0037
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0317	0.0030	0.1014	0.0097
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.5974	0.0930	1.8842	0.2934
M1	Proactive Dam Removal	2020	2023	$ 145.0	$ -	0.2276	0.0016	0.7393	0.0051
			Total - Alternative Plan #1	**$ 195.2**	**$ -**	**1.2221**	**0.0063**	**3.8919**	**0.0199**

A. Overview

This alternative mitigation plan includes all of the controls contemplated in the Proposed Plan (C1 through C6), and also considers reducing risk associated with specific dams by removing them altogether through M1 (Proactive Dam Removal). The risk of failure for a dam can never be reduced to zero – unless the dam is removed.

B. Execution feasibility

SCE's ability to execute the projects in this plan is subject to the time required to obtain the necessary approvals (e.g., DSOD and FERC permitting approval) to begin the work, particularly for M1 (Proactive Dam Removal).

For the purposes of RAMP, SCE has selected three dams associated with small hydroelectric plants that could, in theory, be decommissioned within the time period 2018-2023.

C. Affordability

Initial estimates show that removing the three dams considered in M1 (Proactive Dam Removal) could potentially cost tens of millions of dollars, when factoring in the remote location and the need to perform environmental restoration activities. Alternative Plan #1 provides 12% greater risk reduction than the Proposed Plan. However, the RSE is significantly less efficient (71% worse) than the Proposed Plan due to the high projected costs of decommissioning. Consequently, SCE believes its current controls represent a more cost-effective method of managing risk.

While decommissioning these three dams does not appear to be a cost-effective tool for managing safety risks, SCE's small hydro facilities are facing other economic challenges. SCE anticipates there will be instances in the foreseeable future where the decommissioning of some small hydro facilities, including removal of the associated dams, may be the best course of action. These challenges include the costs to relicense these assets with FERC (likely including reduced electricity generation and other costs to comply with the new licenses), other regulatory and energy market changes, and long-term shifts in precipitation and snowpack due to climate change.

SCE's hydro fleet includes 22 small hydro powerhouses with a total capacity of 95 MW. These small hydro assets entered service between 1893 and 1929. The FERC licenses for 16 of these small powerhouses expire during 2021 year to 2023 year. While appreciable capital refurbishment and improvement has been made over the assets' lives as necessary, much of this infrastructure is original equipment; significant additional refurbishment would be needed if operations are to continue for several more decades.[43]

It is foreseeable that continued negative changes in powerhouse economics could cause SCE to sell, or retire and decommission, certain of the SCE small Hydro assets, rather than complete their upcoming FERC relicensing and make the associated significant capital investments necessary to continue to operate the assets. The impacts of relicensing on small Hydro powerhouse economics will not be known until further progress is made with relicensing. SCE also continues to assess and quantify capital refurbishment needed to continue asset operation for the assumed 40-year duration of a new license. Once these economic factors are known, SCE will be in a better position to forecast which SCE small Hydro assets (if any) might be sold, or retired and decommissioned, rather than relicensed for continued operation for decades into the future.

Decommissioning any of these assets, including associated dam removal projects, will require a large amount of capital to execute. In our 2021 GRC, SCE may propose initiating base rate recovery of the forecast future costs to decommission a portion of SCE's small hydro assets. This reflects SCE's expectation that decommissioning could help address safety risks and

[43] For example, new licenses might include an increase in the "minimum stream release" required at the stream diversion site for the powerhouse (i.e., the location where water is diverted from the stream for conveyance to the powerhouse). For most powerhouses, the powerhouse water discharge is returned to the native stream-bed several miles downstream from where it was diverted. The minimum stream release establishes the flow rate in the native stream bed between the diversion point and the return point. An increase in "minimum stream release" reduces the amount of stream flow diverted to the powerhouse, and therefore reduces the amount of electricity otherwise generated. Powerhouse economics can be negatively affected as a result.

other challenges impacting the cost-effectiveness of small hydro. Incorporating a reasonable level of small hydro decommissioning costs into our GRC forecast will also help ensure that customers who currently benefit from a hydroelectric asset pay a share of whatever costs will eventually be required to remove that asset.

D. Other Considerations

Removing the dams will require extensive discussion with stakeholders, particularly agencies that hold the land the dams are located on, such US Forest Service and National Park Service). These actions will also require either an amendment or surrender of the FERC license for the project, which will allow other stakeholders to raise their concerns.

Removing a dam can also have indirect impacts, such as loss of recreation areas, impacts to water management, and potential economic impacts to the local community. All of these indirect impacts would need to be considered, and quantified where possible.

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VII. Alternative Plan #2

SCE has evaluated the mitigations and controls in Sections III and IV and developed a second alternative plan for risk-reduction activities, summarized in Table VII-1.

Table VII-1 – Alternative Mitigation Plan #2

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0152	0.0021	0.0497	0.0067
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0013
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.4248	0.0354	1.3935	0.1161
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0147	0.0011	0.0483	0.0036
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0357	0.0034	0.1177	0.0112
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.5845	0.0910	1.8162	0.2828
M2	Relocation of campgrounds	2022	2023	$ 5.0	$ -	0.0405	0.0081	0.1243	0.0249
M3	Purchase of Private Residences	2021	2023	$ 3.0	$ -	0.0064	0.0021	0.0195	0.0065
			Total - Alternative Plan #2	**$ 58.2**	**$ -**	**1.1221**	**0.0193**	**3.5699**	**0.0613**

A. Overview

When many of SCE’s dams were constructed, the downstream areas were relatively undeveloped. Many dam owners face the issue of inhabited areas expanding into or encroaching upon potential inundation zones.

SCE has identified two potential avenues to mitigate this situation: (1) working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones; and (2) directly purchasing private residences located in potential inundation zones.

Under this alternative mitigation plan, SCE would pursue all controls identified under the proposed plan (C1 through C6). In addition, SCE would reduce the exposure of populated areas to Uncontrolled Rapid Release of Water from a dam failure. SCE would do so by pursuing M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences).

B. Execution Feasibility

SCE is confident in its ability to execute the physical work involved in the proposed capital maintenance projects.

SCE has relatively low confidence in its ability to relocate campgrounds and acquire private residences. Success in these endeavors would largely be outside of SCE’s control, and would reside mainly in the hands of outside parties.

There is an upcoming opportunity to discuss relocating campsites and campgrounds, because several SCE projects will be going through relicensing in the near future. The relicensing process is a natural forum for discussing these issues with the Forest Service and other stakeholders. We do not know whether the Forest Service would be amenable to this proposal; many of the campgrounds and campsites that would be most beneficial to relocate are also among the most popular.

While purchasing private residences is conceptually simple, success is highly dependent on the willingness of individuals to sell. When BC Hydro implemented this mitigation, they were able to acquire 10 of 11 properties in the potential inundation zone, but encountered one owner who was unwilling to sell.[44]

C. Affordability

Initial evaluation shows that if the relocation and acquisition mitigations can be executed, they would have costs similar to those of major capital projects. SCE has often been required to build and/or fund the construction of campsites as part of the terms of its FERC licenses. The cost can be millions of dollars per campground, particularly if new sanitary or parking facilities are required. An initial evaluation of ten houses in the potential inundation zone of one dam found that they had estimated values ranging from $300,000 to $600,000. Assuming that SCE would need to pay above-market value to motivate owners to sell, the cost for a single dam could be in the millions.

The risk reduction for Alternative Plan #2 is 3% greater than the proposed plan. But the RSE for Alternative Plan #2 is 11% lower than the Proposed Plan. While there is not strong justification to include these mitigations in the current proposed plan, there may be situations identified in the future where relocating or acquiring facilities would be the most cost-effective option to mitigate risk. SCE will evaluate these options on a case-by-case basis.

D. Other Constraints

As discussed, these mitigations are almost entirely dependent on the willingness of the parties owning the potentially inundated facilities to engage.

[44] "The Last Man in Jordan River." Times Colonist, February 26, 2017. http://www.timescolonist.com/islander/the-last-man-in-jordan-river-1.10445193

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has identified capital projects over the 2018-2023 period that will reduce the risk of dam failure. However, the risk reduction potential is small compared to controls and mitigations identified in other RAMP risk chapters. This highlights a challenge many dam owners have experienced when trying to integrate dams into their Enterprise Risk Management programs: balancing management of frequently-occurring risks against very rare risks with catastrophic consequences.

B. Data Collection & Availability

One of the challenges associated with this RAMP chapter is that there is no direct data on failure rates to draw from. This is because SCE has not experienced a dam failure comparable to those discussed in this chapter. SCE's existing Dam Safety Risk Assessment program provided a reasonable starting point for the RAMP risk analysis, given the lack of direct historical data. This assessment is informed by analysis and information obtained to date. The analysis and data are examined in facilitated workshop settings that include SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.

SCE's pilot project currently being performed under the FERC RIDM Guidelines may offer a potential path to improving risk estimates through a combination of field investigations and additional numerical simulations. While this approach is expensive and time-consuming, it could be a viable option for assessing the top dam safety risks.

Additionally, SCE is completing its most recent update of Potential Failure Modes under the Part 12 process in 2018. The new failure modes developed reflect the latest guidance on developing effective PFMS, including lessons learned from the 2017 Oroville Spillway failure. SCE will be re-evaluating its dam safety risks under the new PFMs. The overall portfolio risk is not expected to change substantially, but the new PFMs are more granular and should allow for better mapping to control and mitigation projects to develop better assessments of RSE.

C. Potential Impact of Oroville Spillway Incident in Northern California

In 2017, the failure of the Oroville spillway failure was a highly significant event for the entire dam safety industry. The summary of the Independent Forensic Team (IFT) report concludes by stating:

> *"Although the practice of dam safety has certainly improved since the 1970s, the fact that this incident happened to the owner of the tallest dam in the*

United States, under regulation of a federal agency, with repeated evaluation by reputable outside consultants, in a state with a leading dam safety regulatory program, is a wake-up call for everyone involved in dam safety. Challenging current assumptions on what constitutes 'best practice' in our industry is overdue."[45]

The IFT identified physical factors that contributed to the incident, such as unrecognized design deficiencies, unrecognized poor foundation conditions, and repeated ineffective repairs. SCE personnel involved in dam safety have discussed these factors and used them as a cautionary point of reference when evaluating potential dam safety issues. The IFT also identified contributing organizational factors, such as lack of awareness of dam safety issues at the highest levels of DWR. SCE has implemented measures to foster such awareness, including annual briefings to the President, CEO, and other officers of the Company by the Chief Dam Safety Engineer and the Dam Safety Advisory Board. The first of these briefings occurred in February 2018.

The Oroville incident has resulted in calls for reform of both state and federal dam safety programs. Following this event, the California legislature passed two bills (SB-92 and AB-1270) related to dam safety that Governor Brown signed into law. SB-92 established additional requirements for emergency action plans and inundation mapping for dams. AB-1270 established additional requirements for inspecting dams, and also directed DSOD to "propose amendments to its dam safety inspection and reevaluation protocols to incorporate updated best practices, including risk management, to ensure public safety" by January 1, 2019.

The Oroville incident also led to a request to the Government Accountability Office to perform an audit of FERC Department of Dam Safety and Inspections, and a self-initiated external audit of FERC by a panel of Dam Safety experts. Findings from these audits have not yet been released.

Optimistically, changes to state and federal regulations would incorporate a greater use of risk-informed decision making, so that SCE is better able to prioritize and address dam safety concerns. It is possible that regulations will focus on compliance with standards-based approaches that do not consider risk. This could lead to a substantial increase in dam safety investments without a corresponding significant reduction in risk. It is even possible that risks might increase, because if SCE must undertake a large number of compliance-driven projects

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[45] "Independent Forensic Team Report, Oroville Dam Spillway Incident." January 5, 2018, p. S-3, *available at* https://damsafety.org/sites/default/files/files/Independent%20Forensic%20Team%20Report%20Final%2001-05-18.pdf

that address relatively low risk issues, that might hamper SCE's ability to execute projects that actually mitigate its top dam safety risks.

D. Performance Metrics

SCE currently tracks the following metrics related to dam safety:

- Number of high-hazard dam failures
- Number of Emergency Action Plan Activations
- DSOD Dam Condition Ratings (Note: FERC does not share its condition ratings)

SCE also evaluates a number of operational metrics pertaining to normal operations and dam safety, such as reservoir levels, stream flows, leakage measurements, and snowpack. Collectively, these data help us maintain safe and reliable dams. However, no single metric has been identified that provides a concise, meaningful measure of the safety of Hydro Assets. SCE will continue to evaluate and manage risk through our Dam Safety Risk Assessment Program.

Technical Appendix:
Hydro Asset Safety
Long-Term Risk Analysis Pilot

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Technical Appendix
Hydro Asset Safety – Long-Term Risk Analysis Pilot

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE's RAMP report analyzes key risks from 2018 through 2023. This time period allows for an understanding of how each risk grows, and how each control or mitigation can affect that risk, in the near-term. However, limiting the analysis to this six-year period does not capture the potential costs and benefits of risk controls and mitigations that extend beyond 2023.

SCE has prepared this technical appendix to the Hydro Asset Safety chapter to pilot an analytical approach for a longer-term risk analysis. SCE selected Hydro Asset Safety as the pilot for this alternative approach, due to the long-lived nature of many of its risk controls and mitigations.[1] SCE presents this analysis not to endorse any particular method of analyzing long-term risks, but simply as a means to test and evaluate the application of the concept.[2] In this technical appendix, SCE uses the same bowtie components, controls, and mitigations that were evaluated in the short-term analysis.

In the sections that follow, SCE explains how the drivers and outcomes in the Hydro Asset Safety risk bowtie were revisited to consider their behavior over a 40-year period. We also explain how we revisited the controls and mitigations in Hydro Asset Safety to model a full lifespan of costs and benefits (up to a 40-year maximum).

As described below, taking a longer-term view of risk analysis does not add an unreasonable degree of technical complexity. However, it requires significant judgment to estimate useful lives, forecast asset degradation through decades, estimate driver frequency far into the future, and select (or not select) discount rates to account for uncertainty and to present-value the benefits (financial and otherwise) and costs to the present.[3]

This analysis found that, even under multiple discount rate scenarios, risk reduction activities consistently show higher Risk Spend Efficiency values in this long-term analysis compared to the analysis under the standard RAMP period of 2018-2023. For example, the Proposed Plan in this technical analysis has an RSE of 0.16 (using the 0% discount rate),

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[1] This type of approach could potentially be used for other controls and mitigations in other chapters.

[2] The proposed S-MAP Settlement, includes provisions aimed at considering methodologies for evaluating the full impact of controls and mitigations over their useful lives.

[3] Accordingly, certain dollar figures, estimates of years, and other numbers in our analysis necessarily reflect substantial judgment, and are included for illustrative purposes.

compared to only 0.03 under the standard RAMP period. These results indicate that the full value and benefits of risk controls and mitigations that offer long-lived usefulness may not be captured under the standard RAMP analysis approach.

B. Long-Term Risk Analysis

The RAMP risk evaluation framework used in the nine RAMP chapters can be extended to evaluate effects beyond 2023. The probabilistic risk model can be modified relatively easily from a technical modeling standpoint. But the more challenging aspect of performing this long-term analysis is developing the model input parameters to account for potential changes over long periods of time. These key inputs parameters include:

- Determination of growth of unmitigated risk over time. For example, a driver frequency may be reasonably modeled as constant over a six-year period, but could change substantially over decades.
- Rate of escalation to use for costs and financial consequences;
- Method and discount rate to apply to all risk reduction benefits (safety, reliability, financial);
- Effectiveness of controls / mitigations over time, and incorporation of any associated estimates of asset degradation;
- Changes in uncertainty bounds over time.[4]

Input parameters for the various controls and mitigations must also reflect the expected "durability" of the risk-reduction benefits. That is, over what period of time is an investment considered to be reducing risk. The risk reduction benefit of an inspection might extend for a few years, while the benefit of a structural modification might last decades. In some cases, adjusting operations or removing a particular hazard might reduce risk permanently.

C. Evaluation of Long Term Risk Results

In financial cost-benefit analyses, the common practice is to discount future costs and benefits to reflect the fact that an amount of money invested today could be invested and (on average) earn a rate of return, and would therefore provide higher worth than the same amount of money in the future.

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[4] Uncertainty in this analysis is captured in the probabilistic distributions for consequences (for example, the standard deviation for a normal distribution could increase over time to capture fluctuations in population).

Social discounting[5] is practiced by government agencies such as the EPA,[6] and is also generally applied to financial costs and benefits. There is no established practice for discounting benefits of non-financial metrics, such as injuries or fatalities.

To examine the potential impact of discounting on risk analyses, SCE has evaluated the long-term risk analysis results presented in this chapter considering discount rates of 0%, 5% and 10% to risk reduction benefits expressed in MARS units. This exercise is illustrative, and SCE makes no claim that any of these values are appropriate for use in future RAMP filings. Table I-1 shows summary results on a mean basis.[7]

[5] "Social discounting" takes into account what benefits society as a whole, rather than what benefits an individual, a group of individuals, or an organization.

[6] "Guidelines for Preparing Economic Analyses, Chapter 6: Discounting Future Benefits and Costs." National Center for Environmental Economics, Environmental Protection Agency, December 17, 2010.

[7] SCE shows results on a mean basis in this table solely to simplify the discussion; tail-average results are also considered, but omitted from this table for simplicity.

Table I-1 – Summary of Long-Term Risk Analysis Results

Inventory of Controls & Mitigations			Mitigation Plan		
ID	**Name**		**Proposed**	**Alternative #1**	**Alternative #2**
C1	Seismic Retrofit		x	x	x
C2	Dam Surface Protection		x	x	x
C3	Spillway Remediation and Improvement		x	x	x
C4	Low Level Outlet Improvement		x	x	x
C5	Seepage Mitigation		x	x	x
C6	Instrumentation and Communication Improvements		x	x	x
M1	Proactive Dam Removal			x	
M2	Relocation of Campgrounds				x
M3	Purchase of Private Residences				x
Mean (MARS)	*Cost Forecast ($ Million)*		$50.2	$195.2	$58.2
	Baseline Risk	*6 years*	4.64	4.64	4.64
		40 years	36.27	36.27	36.27
	Risk Reduction (MRR)	*6 years*	1.09	1.22	1.12
		40 years (0% discount)	8.04	14.20	8.94
		40 years (5% discount)	5.07	7.91	5.50
		40 years (10% discount)	3.81	5.48	4.08
	Risk Spend Efficiency (RSE)	*6 years*	0.02	0.01	0.02
		40 years (0% discount)	0.16	0.07	0.15
		40 years (5% discount)	0.10	0.04	0.09
		40 years (10% discount)	0.08	0.03	0.07

6 year period is 2018-2023

40 year period is 2018-2057

II. Long-Term Risk Analysis for Hydro Asset Safety

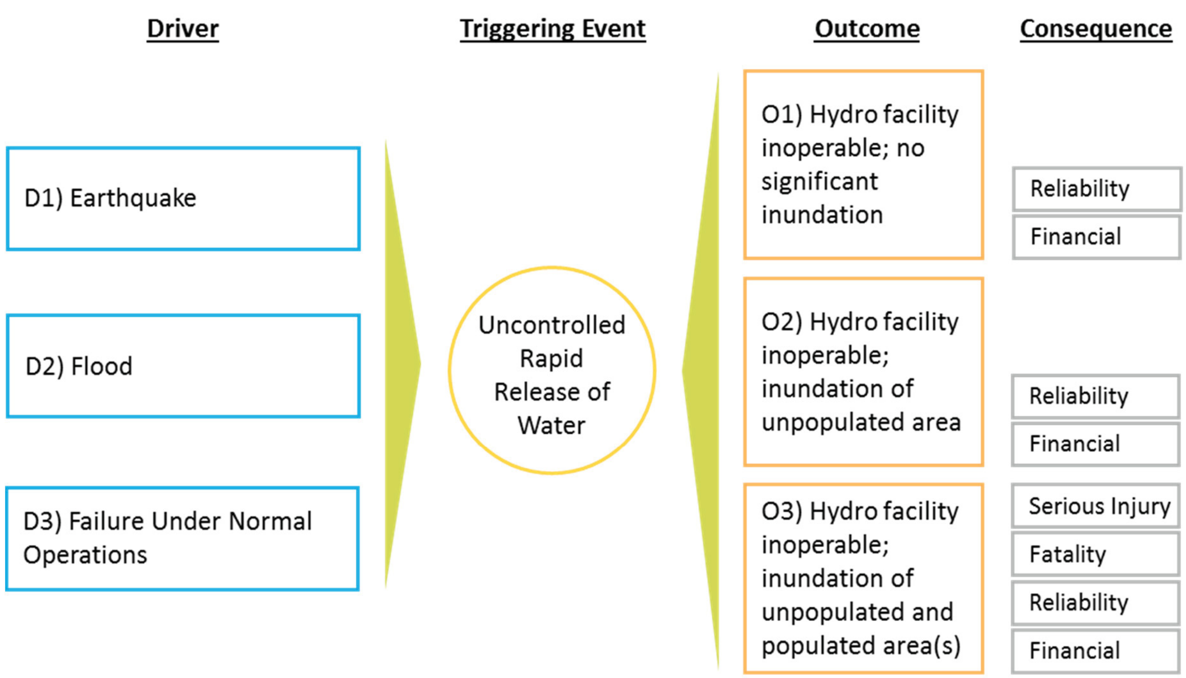
A. Background

Chapter 8 – Hydro Asset Safety analyzes the risk posed by SCE's hydro assets, current actions taken to manage the risk, and mitigation plans to address the risk from 2018-2023. To demonstrate how analysis over a longer time period might be performed, SCE extended the analysis to 2057, for a total duration of 40 years. This section discusses how the inputs to the RAMP model were modified for the long-term analysis.[8]

B. Risk Bowtie

SCE used the Hydro Asset Safety Risk bowtie shown below in Figure II-1. No changes were made to the bowtie for the long-term analysis.

Figure II-1 – Hydro Asset Safety Risk Bowtie



C. Driver Analysis

SCE has identified three drivers (Earthquake; Flood; Failure Under Normal Operations) that could lead to the uncontrolled and rapid release of water. Over the period 2018-2023, the

[8] See Chapter 8, Section II for a detailed discussion of the baseline risk for Hydro Asset Safety.

frequency of these drivers is held constant. SCE believes this is appropriate. However, over a 40-year period, SCE believes it is possible that the driver frequencies may change significantly. The section discusses how these changes were modeled for purposes of the long-term analysis.

1. D1 – Earthquake

Patterns of seismic activity shift over time. But these changes occur over temporal scales of hundreds or thousands of years. However, as dams age they could potentially become more vulnerable to earthquakes. For purposes of this exercise, SCE assumes an exponential annual growth[9] in driver frequency of 2% starting in 2024. The baseline annual frequency of this driver grows from 0.0027 (1 in 370 years) in 2023 to 0.0053 (1 in 189 years) by 2057.

2. D2 – Flood

The frequency and magnitude of extreme floods will be impacted by climate change. SCE has commissioned studies to evaluate the potential impact on its dams and found that under the range of climate scenarios considered,[10] the frequency of floods that could threaten the safety of SCE dams could increase by a factor of 30%, or decrease by a factor of 50%.

Additionally, aging of a dam could potentially increase the vulnerability to failure from severe flooding. For purposes of this exercise, SCE assumes an exponential annual growth in driver frequency of 2%, starting in 2024. The baseline annual frequency of this driver grows from 0.0024 (1 in 416 years) in 2023 to 0.0053 (1 in 213 years) by 2057.

3. D3 – Failure under Normal Operations

The frequency of failures under Normal Operations may increase with age without periodic major capital refurbishment. There is insufficient data to develop a trend. For purposes of this exercise, SCE assumes an exponential annual growth in driver frequency of 2% starting in 2024. The baseline annual frequency of this driver grows from 0.0006 (1 in 1,667 years) in 2023 to 0.0012 (1 in 833 years) by 2057.

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[9] Exponential growth occurs when the rate of change of a value is proportional to that value. Mathematically, if a parameter has a value x_0 in year 0 and grows exponentially with rate r, then the value in year T will be $x_0(1 + r)^T$.

[10] Two scenarios were selected to "bound" a suite of 234 global climate change model projections from the Coupled Model Intercomparison Project Phase 5 (CMIP5) collection. The "hot-dry" scenario uses the 10th-percentile change in precipitation and a 90th percentile change in temperature. The "warm-wet" scenario uses the 90th-percentile change in precipitation and the 10th-percentile change in temperature.

D. Triggering Event - Uncontrolled Rapid Release of Water

SCE defines the Triggering Event as the Uncontrolled Rapid Release of Water (URRW) from a Hydro High-Hazard Dam. No changes to the event definition are required for the long-term analysis.

E. Outcomes

We include the same outcomes and associated probabilities of occurrence in this technical analysis as we presented in Chapter 8. Outcome likelihoods are assumed for this exercise to remain constant over time.[11]

The parameters of the consequence distributions for each outcome are modeled as constant over the 2018-2023 period. Starting in 2024, these parameters are adjusted to reflect possible changes in consequences over time.

In some cases there may be an expectation that the consequences of an outcome will change over time, but there may be insufficient information to determine whether that change will result in an increase or decrease. For example, reliability impacts scale with the local population. It is reasonable to expect that population will change over 40 years, but in some areas it may not be possible to determine if it will grow or shrink. SCE has chosen to model this by holding the average of the distribution constant and increasing the uncertainty of the distribution over time, as shown in Figure II-2. The average of the distribution remains fixed, but the uncertainty, as measured by the 90% confidence interval,[12] increases by approximately 30% from 2023 to 2057.

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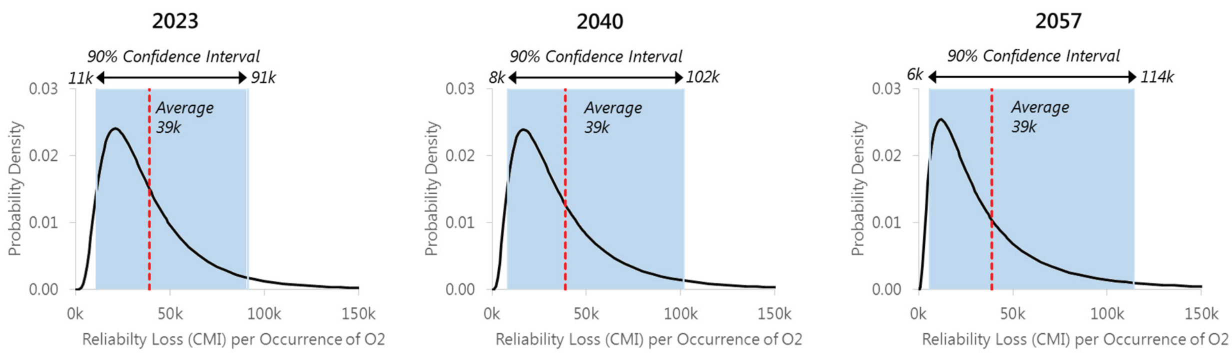
[11] SCE chose to keep the outcome likelihood percentages constant over time to reduce complexity in this analysis. However, it is plausible, and perhaps likely, that a comprehensive analysis would yield changes in annual outcome likelihood values that would have to be justified and modeled.

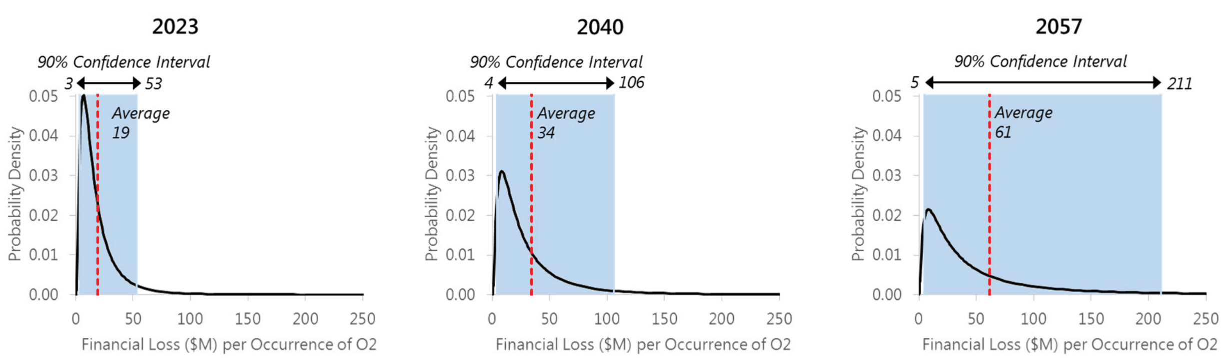
[12] The 90% confidence interval is defined as the range between 5^{th}- and 95^{th}-percentile values of a distribution. It is expected that 90% of the samples drawn from a distribution will fall within this range.

Figure II-2 – Evolution of a Reliability Consequence Distribution over Time



In addition to growing uncertainty over time, there may be baseline trends that will increase or decrease consequences over time. For example, financial losses for an event that occurs 20 years in the future will almost certainly be greater than those for an identical event that occurs today, as cost for materials and labor rise over time. SCE has chosen to model this by increasing both the average and the uncertainty of the distribution, as shown in Figure II-3.

Figure II-3 – Evolution of a Financial Consequence Distribution over Time



1. O1 – Hydro Facility Inoperable; No Significant Inundation

Outcome O1 can result in Reliability consequences due to unavailability of Hydro Plants and Financial consequences due to lost generation. Over time, the population in the areas served by SCE Hydro Plants may increase or decrease, which would result in a corresponding increase or decrease in Reliability impacts. For purposes of this exercise, this is represented by increasing the uncertainty of the consequence distribution over time. Specifically, the standard deviation of the distribution for Reliability consequences is modeled with exponential annual growth of 1%, starting in 2024. The mean of the distribution is held constant.

Similarly, the value of the generation provided by SCE Hydro Plants may increase or decrease. For purposes of this exercise, the standard deviation of the distribution for Financial consequences is modeled with exponential annual growth of 1%, starting in 2024. The mean of the distribution is held constant.

2. O2 – Hydro Facility Inoperable; Inundation of Unpopulated Area

Outcome O2 can result in Reliability consequences due to unavailability of Hydro Plants and Financial consequences due to lost generation and costs to remediate damage caused by inundation.

As for Outcome O1, the uncertainties of the consequence distributions are modeled as increasing over time. For purposes of this exercise, the standard deviations of the distributions for Reliability and Financial consequences are modeled with exponential annual growth of 1%, starting in 2024.The mean of the distribution for Reliability is held constant, but the cost of construction activities to remediate inundation damage is expected to escalate over time. Consequently, the mean of the distribution for Financial is modeled with exponential annual growth of 3.5%, starting in 2024.

3. O3 – Hydro Facility Inoperable; Inundation of Unpopulated and Populated Area(s)

Outcome O3 can result in Safety consequences due to inundation of populated areas, Reliability consequences due to unavailability of Hydro Plants and possible inundation damage to the local electrical system, and Financial consequences due to lost generation and costs to remediate damage caused by inundation.

Similar to Outcomes O1 and O2, the uncertainties of the consequence distributions are modeled as increasing over time. For purposes of this exercise, the standard deviations of the distributions for Serious Injury, Fatality, Reliability and Financial consequences are modeled with exponential annual growth of 1%, starting in 2024. The means of the distributions for Serious Injury, Fatality and Reliability are held constant. Similar to Outcome O2, the mean of the distribution for Financial is modeled with an exponential annual growth of 3.5%, starting in 2024, to represent the expected escalation in the cost for construction activities needed to remediate inundation damage.

III. Compliance & Controls

This section discusses how the modeling of the controls has been modified for the long-term analysis.[13]

As was done in the Hydro Safety Asset chapter, compliance activities (CM1-CM4) are not risk modeled in this technical appendix. The remaining controls consist of hydro capital maintenance refurbishment and/or replacement activities (C1-C6), all of which are capital investments necessary for maintaining dam infrastructure and equipment.[14] The useful life of the various types of investments may vary. For example, concrete or earth reinforcement of a dam could provide benefit for several decades, while a surveillance camera is likely to need replacement after 10 years.

For this exercise, SCE models each family of controls as having a "design life." A design life is a period over which the investment provides the full intended risk-reduction benefit. Once the age of the control equals the design life, the benefit is modeled as degrading linearly over time until the age of the control reaches twice the design life. At that point, the control is modeled to be fully ineffective. Note that is different from the modeled depreciation of the asset.[15]

To illustrate how this is modeled, please consider a hypothetical control C0 with a total mitigation effectiveness of 30% and a Design Life of 10 years. C0 is implemented in three "phases" over years 1-3, with each phase assumed to provide 10% mitigation effectiveness. As shown in Figure III-1, the full mitigation effectiveness is reached in year 3. The first "phase" reaches the end of its design life at year 11 and begins to degrade starting in year 12, with the second and third phases following, until the control is completely ineffective in year 23.

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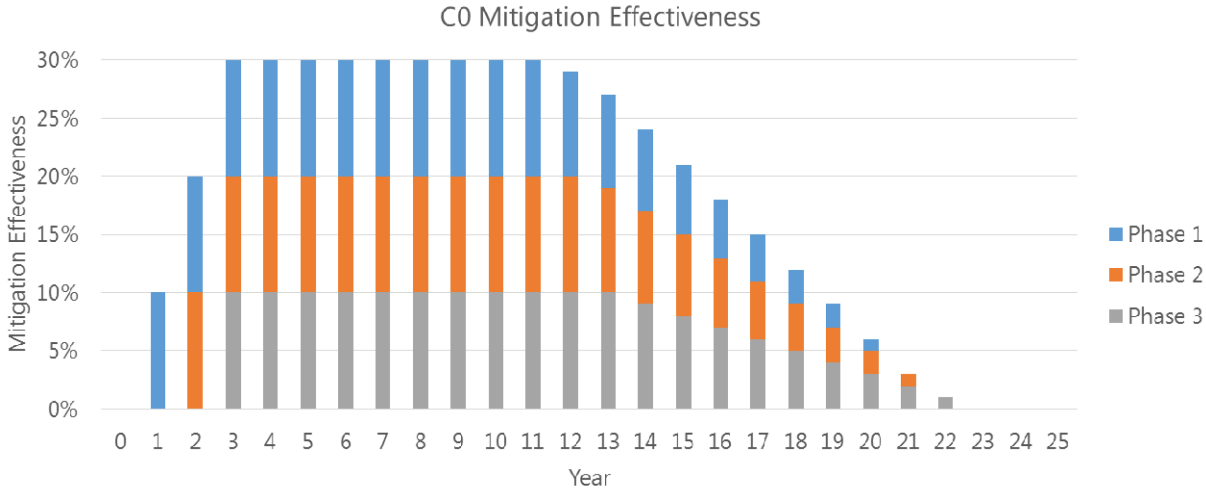
[13] See Chapter 8, Section III for a detailed discussion of Compliance & Control activities for Hydro Asset Safety.

[14] This analysis assumed that ongoing capital-related expenses pertaining to the controls and mitigations evaluated are *de minimis*.

[15] "Design life" is used for purposes of this illustrative analysis. To the extent SCE deploys this long-term risk assessment methodology for broader risk analysis in the future, SCE will need to work with stakeholders to identify the appropriate design life parameters to use. For example, this could mean aligning to asset depreciation schedules or other accounting principles.

Figure III-1 – Long-Term Control Effectiveness Model



A. C1 – Seismic Retrofit

This work may include rehabilitating and/or replacing concrete, re-compacting and/or replacing embankment materials, installing post-tensioned anchors, and constructing reinforcing elements such as steel braces, concrete buttresses or earthen berms.

Due to the durable nature of the materials involved, these modifications are considered to be relatively long-lived. The reductions to D1 (Earthquake) are modeled with a design life of 30 years.

B. C2 – Dam Surface Protection

SCE, along with the previous owners of the SCE dams, have consistently attempted to protect these structures against deterioration by waterproofing the upstream surfaces with methods such as grouting or polysulfide coatings.

The manufacturer of the liner cites cases where installations have been in service for 30 years. However, SCE dams are located in environments that may shorten the effective life-span, due to large swings in temperature between winter and summer, and prolonged periods of direct exposure to sunlight (which degrades the plastic geomembrane). The reductions to D3 (Failure Under Normal Operations) are modeled with a design life of 20 years.

C. C3 – Spillway Remediation and Improvement

SCE repairs and improves the spillways at its dams. This work can include refurbishing deteriorated concrete, installing or improving protective measures (such as water-stops between concrete slabs or drains beneath spillway chutes), rehabilitating or improving spillway gate structures, expanding the spillway, or armoring embankment dams to allow them to withstand overtopping of water.

Due to the durable nature of the materials involved, these modifications are considered to be relatively long-lived. The reductions to D2 (Flood) are modeled with a design life of 30 years.

D. C4 – Low Level Outlet (LLO) Improvements

SCE performs LLO repair and improvements for dams. LLOs are systems that can be used to lower the reservoir level of a dam in a controlled manner. In addition to managing water levels during normal operations, LLOs can be used in an emergency to empty the reservoir to prevent or reduce the consequences of dam failure.

The materials involved (concrete and steel) are durable in nature of the materials involved, but some components of the system (valves, valve operators, seals) may be more vulnerable to deterioration. The reductions to D2 (Flood) are modeled with a design life of 20 years.

E. C5 – Seepage Mitigation

SCE performs seepage mitigations to reduce the likelihood of initiation and progression of internal erosion in embankment dams. This work can include constructing or rehabilitating drains to reduce seepage, constructing filters to mitigate erosion, and filling sinkholes or joints in the foundation on the upstream side of the dam.

The materials involved (earth and rockfill) are durable in nature, but will be likely be continuously subjected to seepage which could degrade the mitigation effectiveness over time. The reductions to D3 (Failure Under Normal Operations) are modeled with a design life of 20 years.

F. C6 – Instrumentation and Communication Improvements

Many SCE dams are in remote locations. SCE uses instrumentation to monitor the condition of these dams at centralized Hydro Control Rooms, where an operator is present 24 hours a day. SCE performs work to maintain and improve the capability and reliability of dam instrumentation. This work can consist of repairing, replacing, or installing instruments. The work also encompasses repairing and/or improving the systems that transmit the instrument readings via fiber, radio, and/or satellite to Hydro Control Rooms.

The electronic systems involved are designed with consideration of the environmental challenges at SCE dam sites, however, they are likely to be short-lived compared to structural improvements. The reductions to the Safety impacts of Outcome O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) are modeled with a design life of 10 years.

IV. Mitigations

In addition to the controls describe above, SCE identified additional risk mitigations that could be performed over the 2018-2023 RAMP period. This section discusses how the modeling of these programs and processes has been modified for the long-term analysis.[16]

A. M1 – Proactive Dam Removal

During the normal course of managing its portfolio of dams, SCE evaluates situations where decommissioning may be the appropriate *reactive* measure to an emergent dam safety issue. SCE could, hypothetically, alter its strategy to consider *proactively* decommissioning dams to reduce risk. This mitigation contemplates the proactive removal of dams, which includes mitigating the impacts of dam removal on the environment and any additional flooding that might occur downstream due to the removal of a dam.

As this mitigation involves the permanent removal of a dam, the modeled reductions to D1 (Earthquake), D2 (Flood) and D3 (Failure Under Normal Operations) do not degrade with time.

B. M2 – Relocation of Campgrounds

At many SCE dams, a large portion of the population at risk in a dam failure are located in campgrounds. Relocation of these sites could potentially reduce risk. SCE may be able to accomplish this mitigation by working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones.

As this mitigation involves the permanent relocation of populated areas, the modeled reductions to the Safety impacts of O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) do not degrade with time.

C. M3 – Purchase of Private Residences

Similar to the relocation of campgrounds, by purchasing private residences in the potential inundation zone, SCE could reduce the consequences of a dam failure.

As this mitigation involves the permanent removal of populated residences, the modeled reductions to the Safety impacts of O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) do not degrade with time.

[16] See Chapter 8, Section IV for a detailed discussion of Mitigation activities for Hydro Asset Safety.

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V. Proposed Mitigation Plan

SCE evaluated the Proposed Plan of risk-reduction activities from the Hydro Asset Safety chapter, which consisted of controls C1 through C6. The results of the long-term analysis of the Proposed Plan are shown below in Table V-1 on a mean basis, and in Table V-2 on a tail average basis.

Table V-1 – Proposed Plan Long-Term Analysis Results (Mean)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.02	0.18	0.09	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0018	0.0010	0.0006	0.0004	0.0038	0.0022	0.0016
C3	Spillway Remediation and Impovement	12.0	30	0.42	4.13	1.98	1.19	0.04	0.38	0.20	0.13
C4	Low Level Outlet Improvements	13.4	20	0.015	0.111	0.061	0.039	0.001	0.009	0.006	0.004
C5	Seepage Mitigation	10.5	20	0.04	0.32	0.17	0.11	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.60	2.21	1.68	1.33	0.09	0.44	0.35	0.30
	Total - Proposed Plan	**50.2**	**-**	**1.09**	**6.95**	**3.98**	**2.72**	**0.02**	**0.16**	**0.10**	**0.08**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Table V-2 – Proposed Plan Long-Term Analysis Results (Tail Average)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.60	0.29	0.17	0.01	0.09	0.05	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0060	0.0032	0.0021	0.0013	0.0122	0.0072	0.0051
C3	Spillway Remediation and Impovement	12.0	30	1.39	13.47	6.43	3.83	0.12	1.24	0.65	0.44
C4	Low Level Outlet Improvements	13.4	20	0.05	0.36	0.20	0.13	0.00	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.12	1.04	0.56	0.36	0.01	0.11	0.06	0.05
C6	Instrumentation & Communication Improvements	6.4	10	1.87	6.99	5.30	4.21	0.29	1.38	1.12	0.95
	Total - Proposed Plan	**50.2**	**-**	**3.47**	**22.47**	**12.77**	**8.70**	**0.07**	**0.52**	**0.32**	**0.24**

All of the controls provide greater total risk reduction benefits outside of the RAMP time period (2018-2023) than within it, regardless of discount rate used. This is especially pronounced for controls with longer design lives, such as C3 (Spillway Remediation and Improvement), where the MRR from 2024-2057 (with 0% discount rate) is approximately ten times the MRR over the period from 2018-2023. In contrast, C6 (Instrumentation & Communication Improvements), has the highest MRR over the period from 2018-2023 but captures only four times more benefit over the 2024-2057 (with 0% discount rate). This is because the benefits are less “durable.”

The long-term risk analysis also highlights a change in the RSE scores. For example, the tail average RSE for C6 increases from 0.29 over the 2018-2023 period to 1.38 when measured over 40 years (a factor of 5). In contrast, the RSE for C3 increases from 0.12 to 1.24 (a factor of 10).

In this example, the ranking of mitigations based on RSE does not change between the near-term and long-term analyses. This is partly due to the fact that these controls are asset-based capital programs with longer design lives. As we can see from these results and how the MRR and RSE can change based on the design life of the control, we can envision situations where the relative MRR and RSE of short-term and long-term controls and mitigation may be significantly influenced by the time window of the analysis.

VI. Alternative Mitigation Plan #1

SCE evaluated Alternative Plan #1 as designed in the Hydro Asset Safety chapter, which consists of the control activities of the Proposed Plan (C1 through C6) and adds M1 (Proactive Dam Removal). The results of the long term-analysis of Alternative Plan #1 are shown below in Table VI-1 on a mean basis, and Table VI-2 on a tail-average basis.

Table VI-1 – Alternative Plan #1 Long-Term Analysis Results (Mean)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.01	0.17	0.08	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0017	0.0009	0.0006	0.0004	0.0035	0.0020	0.0014
C3	Spillway Remediation and Impovement	12.0	30	0.34	3.83	1.82	1.08	0.03	0.35	0.18	0.12
C4	Low Level Outlet Improvements	13.4	20	0.02	0.10	0.06	0.04	0.00	0.01	0.01	0.00
C5	Seepage Mitigation	10.5	20	0.03	0.29	0.16	0.10	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.60	2.00	1.51	1.20	0.09	0.40	0.33	0.28
M1	Proactive Dam Removal	145.0	Permanent	0.23	6.58	3.07	1.80	0.00	0.05	0.02	0.01
	Total - Alternative Plan #1	**195.2**	**-**	**1.22**	**12.98**	**6.69**	**4.26**	**0.01**	**0.07**	**0.04**	**0.03**

Table VI-2 – Alternative Plan #1 Long-Term Analysis Results (Tail Average)

ID		Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.55	0.26	0.15	0.01	0.08	0.04	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0055	0.0029	0.0019	0.0012	0.0112	0.0065	0.0046
C3	Spillway Remediation and Impovement	12.0	30	1.07	12.45	5.88	3.48	0.09	1.13	0.58	0.38
C4	Low Level Outlet Improvements	13.4	20	0.05	0.33	0.18	0.11	0.00	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.10	0.95	0.51	0.32	0.01	0.10	0.06	0.04
C6	Instrumentation & Communication Improvements	6.4	10	1.88	6.31	4.78	3.79	0.29	1.28	1.04	0.88
M1	Proactive Dam Removal	145.0	Permanent	0.74	21.43	9.94	5.82	0.01	0.15	0.07	0.05
	Total - Alternative Plan #1	**195.2**	**-**	**3.89**	**42.04**	**21.55**	**13.69**	**0.02**	**0.24**	**0.13**	**0.09**

The long-term analysis shows that M1 provides large risk-reduction benefits over the period from 2024-2057. This is due in large part because the nature of the mitigation (dam removal) means the risk-reductions are permanent and do not degrade with age. The tail average RSE of M1 jumps from 0.01 over 2018-2023 to 0.15 when considering the period from 2018-2057. This increase in RSE relative to the increases in the controls indicates that capturing the long-term benefits of mitigations could potentially change the mitigations we select.

In this case, even though Alternative Plan #1 (with 0% discount rate) provides nearly twice the tail average MRR of the Proposed Plan over 2018-2057 (45.93 versus 25.94, respectively), the tail average RSE of Alternative Plan #1 (again, with 0% discount rate) is still 54% less than the Proposed Plan (0.24 versus 0.52, respectively). This is largely due to the high cost of M1 (Proactive Dam Removal), which is included in Alternative Plan #1 and not in the Proposed Plan.

Applying a discount rate of 5% reduces the tail average MRR of Alternative Plan #1 over the 2018-2057 period by 45%. The MRR is even further reduced when a discount rate of 10% is applied; however, it still remains many times higher than the MRR of this plan over the 2018-2023 period.

Using a 5% discount rate, the tail average RSE of Alternative Plan #1 is about 59% less than the Proposed Plan. Based on the initial results, using discount rates significantly affects the RSE of all controls and mitigations. These rates affect can have a greater effect on longer-lived activities.

VII. Alternative Mitigation Plan #2

SCE evaluated Alternative Plan #2 as designed in the Hydro Asset Safety chapter, which consists of the control activities of the Proposed Plan (C1 through C6) and adds M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences). The results of the long term-analysis of Alternative Plan #2 are shown below in Table VII-1 on a mean basis, and in Table VII-2 on a tail average basis.

Table VII-1 – Alternative Plan #2 Long-Term Analysis Results (Mean)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.02	0.18	0.08	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0018	0.0010	0.0006	0.0004	0.0036	0.0021	0.0015
C3	Spillway Remediation and Impovement	12.0	30	0.42	3.96	1.90	1.14	0.04	0.37	0.19	0.13
C4	Low Level Outlet Improvements	13.4	20	0.01	0.11	0.06	0.04	0.00	0.01	0.01	0.00
C5	Seepage Mitigation	10.5	20	0.04	0.31	0.17	0.11	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.58	2.13	1.61	1.28	0.09	0.42	0.34	0.29
M2	Relocation of Campgrounds	5.0	Permanent	0.04	1.03	0.50	0.31	0.01	0.21	0.11	0.07
M3	Purchase of Private Residences	3.0	Permanent	0.01	0.12	0.06	0.04	0.00	0.04	0.02	0.01
	Total - Alternative Plan #2	**58.2**	**-**	**1.12**	**7.82**	**4.38**	**2.96**	**0.02**	**0.15**	**0.09**	**0.07**

Table VII-2 – Alternative Plan #2 Long-Term Analysis Results (Tail Average)

ID		Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.58	0.27	0.16	0.02	0.08	0.04	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0057	0.0031	0.0020	0.0041	0.0118	0.0070	0.0049
C3	Spillway Remediation and Impovement	12.0	30	1.39	12.93	6.17	3.69	0.35	1.19	0.63	0.42
C4	Low Level Outlet Improvements	13.4	20	0.05	0.35	0.19	0.12	0.01	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.12	1.00	0.54	0.34	0.03	0.11	0.06	0.04
C6	Instrumentation & Communication Improvements	6.4	10	1.82	6.72	5.10	4.05	0.91	1.33	1.08	0.91
M2	Relocation of Campgrounds	5.0	Permanent	0.12	3.85	1.82	1.08	0.08	0.80	0.39	0.24
M3	Purchase of Private Residences	3.0	Permanent	0.02	0.44	0.21	0.13	0.02	0.15	0.08	0.05
	Total - Alternative Plan #2	**58.2**	**-**	**3.57**	**25.87**	**14.30**	**9.58**	**0.06**	**0.51**	**0.31**	**0.23**

The long-term analysis shows that M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences) provide significant risk-reduction benefits over the period from 2024-2057. By removing population from potentially threatened areas, the risk-reductions become permanent and do not degrade with time. The tail-average RSE (using a 0% discount rate) for M2 and M3 increase by factors of nine and eight, respectively, when considering a 40-year period instead of a 6-year period. Alternative Plan #2 (using a 0% discount rate) provides 13% greater tail average MRR compared to the Proposed Plan over 2018-2057 (29.44 versus 25.94, respectively). The tail average RSE of Alternative Plan #2 over the same period (again, using a 0% discount rate) is only 2% less than the Proposed Plan (0.51 versus 0.52, respectively).

Applying a discount rate of 5% reduces the tail average MRR of Alternative Plan #2 over the 2018-2057 period by 39%. The MRR is even further reduced when a discount rate of 10% is applied; however, it still remains many times higher than the MRR of this plan over the 2018-2023 period.

Consistent with the results from the Proposed Plan and Alternative Plan #2, these preliminary results show that consideration the time period and use of discounting can significantly affect the calculated risk reduction benefits and risk spend efficiency for mitigations. The selected time period and discount rate could potentially alter the relative RSE ranking of short- and long-lived mitigations.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

The long-term analysis demonstrates that, from a technical modeling perspective, the RAMP framework used in SCE's report can be modified to account for longer-time frames. The selection of input parameters for these long-term analyses should consider potential changes in driver frequency, consequences, and the durability or longevity of the risk-reduction benefits from controls and mitigations.

A long-term analysis may significantly change the calculated MRR and RSE for individual mitigations and controls as well as the MRR and RSE for mitigation plans. In the particular example presented here, with the assumptions used in the analysis, the relative "ranking" by RSE of the Proposed and Alternative Plans did not change. However, a different risk or a different set of assumptions could result in a scenario where the ranking of plans differs based on the time period selected for analysis. This is expected to be especially true when evaluating controls and mitigations with shorter design lives.

The use of discounting of future benefits significantly reduces the MRR from long-lived controls and mitigations. However, in this particularly example, the effect of discounting on RSE was relatively small.

This technical analysis evaluated controls that are funded by capital costs. Applying this framework to short-lived O&M-funded mitigations would require the consideration of ongoing O&M costs, and the presumed ongoing execution of those mitigations over the life of the analysis.

B. Next Steps

SCE appreciates the opportunity to present this illustrative longer-term analysis. We look forward to further dialogue with, and feedback from, the Commission and parties on how we can address many of the considerations raised in this technical appendix in future iterations of RAMP.

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL® Company

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Physical Security

Chapter 9

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE's main objective is to safely provide reliable, affordable, and clean electricity to our customers. The physical safety of our workforce, customers, facilities, assets, and equipment is a critical component of this responsibility. The threat landscape that SCE and other electric utilities face is diverse – threats range from simple acts of theft to coordinated attacks on the electric grid.

This chapter evaluates the physical security of our facilities, and the risks posed to the people and assets in those facilities. In this RAMP chapter we define physical security consistent with related Commission efforts: physical security encompasses those elements and strategies directly involved in physical protection, such as implementing perimeter walls and fencing, lighting, cameras, and conducting security patrols.[1]

We build on this basic definition by adding a broader set of activities. These activities (in combination with the right processes, procedures and training) help us deter, monitor, and mitigate attempts to compromise SCE's facilities, equipment, or people in those facilities.

In this chapter SCE quantifies the physical security risk, and assesses how to mitigate physical security threats. SCE identified two primary threats that can compromise SCE's physical security:

- Third party breaching the security perimeter due to security system bypass/breach, human error, or process failure;
- An insider (e.g., an SCE employee or authorized contractor) using their access or knowledge with malicious intent.

[1] Brinkman, Ben; Chen, Connie; O'Donnell, Arthur; Parkes, Chris. (2012, February.) Regulation of Physical Security for the Electric Distribution System. *California Public Utilities Commission.* Retrieved from www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454097 Whitepaper to discuss regulatory framework around electric distribution system physical security, including process and methodology recommendations for CPUC.

This chapter analyzes incidents occurring within the perimeter of our facilities that result in theft, trespassing, workplace violence, or a coordinated attack targeting multiple substations.[2]

SCE identified a number of compliance activities, controls, and new mitigations to address this risk.

- This chapter describes two compliance activities related to the North American Electric Reliability Corporation (NERC):[3] NERC CIP-014 (CM1) and NERC CIP-003-V6 (CM2). These activities protect the bulk electric system (BES) operations from security incidents.

This chapter evaluates four controls:[4]

- Grid Infrastructure Protection Base (C1a) & Enhanced (C1b): This includes activities to protect our electric grid from multiple physical threats;
- Protection of Generation Capabilities (C2): This includes activities to protect our generation facilities;
- Non-Electric Facilities - Protection of Major Business Functions Base (C3a) & Enhanced (C3b): This includes activities to protect our major business functions and administrative facilities;
- Asset Protection (C4): This includes employing security officers at our facilities, performing background checks, and implementing security training to our workers.

Finally, this chapter evaluates five mitigations:[5]

- Insider Threat program enhancements (M1a & M1b): Two options to improve the protection of our assets, our workers, and the public against insider threat.
- Smart Key Program (M2, M3, M4): A phased approach to replace conventional lock-and-key devices with Smart Key technology.
    - Phase 1 (M2): Limited population;
    - Phase 2 (M3): Expanded to remaining electrical facilities;
    - Phase 3 (M4): Expanded to remaining business function facilities.

SCE has developed three risk mitigation plans:

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[2] All of SCE's facilities are in scope, including, for example: office buildings, substations, switching centers, grid control centers, data centers, electricity generation facilities, IT facilities, warehouses, and service centers.

[3] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[4] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

[5] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

- The Proposed Plan continues existing programs (C2 & C4), proposes the enhanced version of current controls (C1b & C3b), improves our current Insider Threat program (M1a), and rolls out the initial phase of the Smart Key Program (M2).

- Alternative Plan #1 continues existing programs (C2 & C4), proposes the enhanced version of current controls (C1b & C3b), improves our current Insider Threat program with the enhanced version (M1b), and rolls out all three phases of the Smart Key Program (M2, M3, & M4).

- Alternative Plan #2 continues existing programs (C2 & C4), continues existing base level controls (C1a & C3a) and adds the same incremental efforts as the Proposed Plan to improve our current Insider Threat program (M1a).

B. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 – Chapter Scope

IN SCOPE	• Acts that occur within the security perimeter of SCE facilities that are protected by physical security measures. Facilities in-scope include office buildings, substations, switching centers, grid control centers, data centers, electricity generation facilities, IT facilities, warehouses, and service centers.
OUT OF SCOPE	• Acts that occur beyond the security perimeter of SCE facilities. Potential examples include: incidents related to power lines, poles and transmission towers; or incidents occurring when SCE field workers perform work on or around a customer's property.[6] • Public safety incidents resulting from criminal activity that occurs as a result of the public's unauthorized interactions with SCE's electric and/or non-electric assets. For example, serious injury to an individual from contacting energized equipment while engaged in attempted theft, whether such attempt occurs inside or outside the physical security perimeter of SCE facilities.

[6] There are no reasonable and substantial physical security measures to protect assets that are located beyond SCE facilities.

C. Summary Results

In this chapter, SCE identifies the primary drivers and outcomes of physical security threats, and outlines the physical security controls and mitigations that are most effective in limiting SCE's exposure to those threats. Table I-2 summarizes this chapter's baseline risk analysis, controls, and contemplated mitigations, and gives portfolio results that we project over the 2018 – 2023 period.

Table I-2 – Summary of Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1a	Grid Infrastructure Protection - Base			X
C1b	Grid Infrastructure Protection - Enhanced	X	X	
C2	Protection of Generation Capabilities	X	X	X
C3a	Non-electric Facilities/Protection of Major Business Functions - Base			X
C3b	Non-Electric Facilities/Protection of Major Business Functions - Enhanced	X	X	
C4	Asset Protection	X	X	X
M1a	Insider Threat Program Enhancement & Information Analysis - Base	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites		X	
Mean (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	3.67	3.67	3.67
	Risk Reduction (MRR)	1.77	2.04	1.40
	Residual Risk	1.90	1.64	2.27
	Risk Spend Efficiency (RSE)	0.027	0.029	0.026
Tail Average (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	14.16	14.16	14.16
	Risk Reduction (MRR)	6.98	8.05	5.52
	Residual Risk	7.19	6.11	8.64
	Risk Spend Efficiency (RSE)	0.108	0.113	0.101

Figures represent 2018 - 2023 annual averages.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

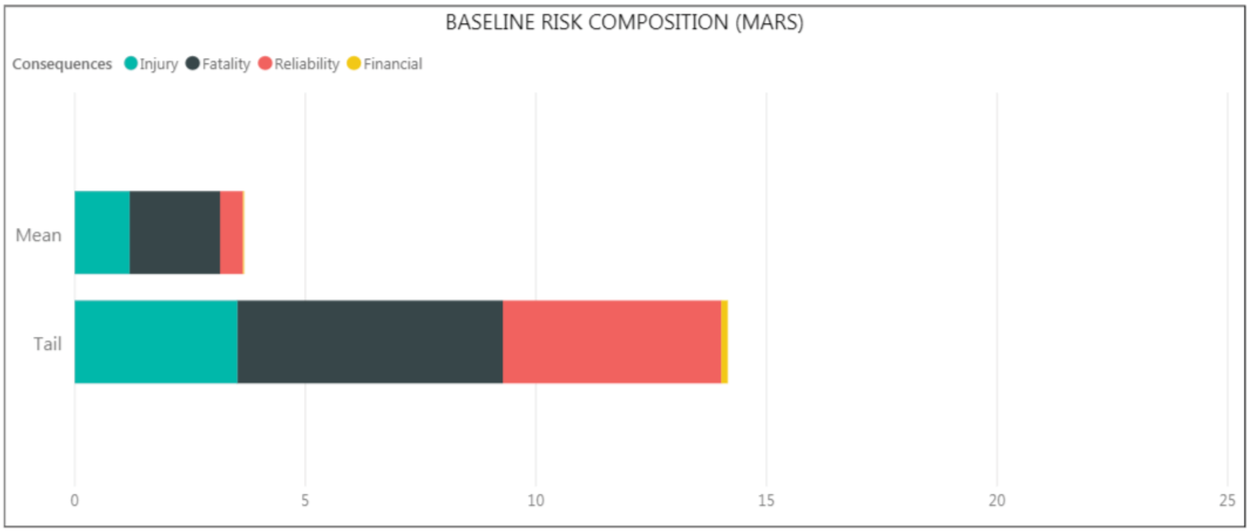
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 illustrates the composition of consequences within the baseline risk. This figure shows that on a mean basis, the majority of risk is associated with safety consequences.

On a tail-average basis, safety still predominates as a consequence for this risk. However, reliability significantly increases in impact. This is due to the low-likelihood, high-consequence impacts of Outcome 4 (Coordinated Attack on Multiple Substations), which results in significant reliability impacts.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

D. Sensitive, Confidential Information Must Be Protected

SCE may be unable to share information beyond a certain level of detail to protect sensitive and confidential security data. Exposing detail about SCE's security protocols could compromise the integrity and secrecy of our physical security approach, and enable an attacker to avoid or defeat the security safeguards.

This chapter discloses information in a manner that does not compromise SCE’s physical security. To promote transparency and help stakeholders access additional and sensitive information that might be necessary to answer specific questions, SCE can provide an in-person briefing, or take other reasonable measures to convey information as appropriate.

II. Risk Assessment

A. Background

SCE maintains operations at many different facilities throughout our service territory. Each facility has various assets that require different levels of security protection – e.g., electrical equipment, communication technology, vehicles, workers, etc. The physical security needs of each facility can be unique. For example, a high-impact[7] facility, such as a 500 kV transmission substation, requires aggressive physical security (e.g., gated entry, cameras, gunshot detection, etc.). If SCE's substations and/or their associated primary control centers are rendered inoperable or damaged as the result of a security breach, it will compromise our ability to safely and reliably deliver power to our customers. The National Research Council has noted that a carefully planned and executed attack could "deny large regions of the country access to bulk system power for weeks or even months."[8]

In contrast, a low-impact[9] facility, such as a laydown yard that houses material inventory for ongoing work, may require fewer controls. Moreover, office buildings require different levels of security based on the criticality, occupancy level, and sensitivity of operations that occur at each location.

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[7] SCE categorizes SCE's BES facilities under California Independent System Operator (ISO) control as Tier 1, Tier 2, Tier 3 and Tier 4. Each tier has associated physical security requirements based on criticality and impact to the BES. High-impact facilities are those categorized as Tier 1-3 sites, or identified in the annual business impact analysis as being critical to the BES or to primary SCE business functions, or having high impact on the community.

[8] National Research Council (2012). Terrorism and the Electric Power Delivery System. Washington, DC: The National Academies Press. https://doi.org/10.17226/12050, Retrieved from http://www.nap.edu/catalog/12050/terrorism-and-the-electric-power-delivery-system. This is a study completed by several organizations on the impact of coordinated attacks on the power grid. It discusses vulnerability based on several factors, and examines potential effects on the economy and the health/welfare of society.

[9] For physical security purposes, low-impact facilities are simply defined as those not meeting the criteria of a high-impact facility.

B. Physical Security Threats to Electric Utilities

The internal and external threats facing the utility industry continue to evolve. Between 2011 and 2014, electric utilities reported to the U.S. Department of Energy a total of 348 physical attacks that caused outages or other power disturbances.[10]

California has experienced several major incidents in the past, including harm to individuals. A few example are listed below:

- In 1997, insider sabotage[11] resulted in a three-and-a-half hour power outage in San Francisco that affected 126,000 customers.
- In 2011, an SCE employee shot and killed two SCE managers, and wounded an SCE employee and a contract worker before committing suicide. This incident occurred at a secure SCE facility located in a gated complex equipped with card access readers.[12]
- In 2013, unknown attackers unleashed a coordinated attack on PG&E's Metcalf substation in northern California. The attackers severed six underground fiber-optic lines before firing more than 100 rounds of ammunition at the substation's transformers, causing more than $15 million in damage. The intentional act of sabotage, likely involving more than one gunman, differed from any previous attack on the nation's grid in its scale and sophistication.[13] Metcalf substation is located in a highly concentrated area and supplies electricity to Silicon Valley.

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[10] Reilly, Steve. (2015, March 24.) "Bracing for a Big Power Grid Attack: 'One Is Too Many.'" *USA Today*. Retrieved from https://www.usatoday.com/story/news/2015/03/24/power-grid-physical-and-cyber-attacks-concern-security-experts/24892471/ This newspaper article highlights the frequency of attacks on the power grid and potential risks. It documents several specific physical and cyber-attacks.

[11] Egan, Timothy. (1997, October 24.) "Blackout in San Francisco; Sabotage Is Seen." *New York Times.* Retrieved from https://www.nytimes.com/1997/10/25/us/blackout-in-san-francisco-sabotage-is-seen.html This newspaper article reviews the sabotage at a PG&E facility that caused a substantial power outage in San Francisco.

[12] Khan, Irfan and Becerra, Hector. (2011, December 17.) Edison Office Shooting Victims, Killer Identified. *Los Angeles Times.* Retrieved from http://articles.latimes.com/2011/dec/17/local/la-me-shooting-follow-20111218 This newspaper article discusses a workplace violence incident at SCE's Irwindale facility.

[13] Reilly, Steve. (2015, March 24.) "Bracing for a Big Power Grid Attack: 'One is too Many.'" *USA Today*. Retrieved https://www.usatoday.com/story/news/2015/03/24/power-grid-physical-and-cyber-attacks-concern-security-experts/24892471/ This newspaper article highlights the frequency of attacks on the power grid and potential risks. It documents several specific physical and cyber-attacks.

- Between 2015 and 2017, there were two reported safety incidents where intruders either suffered serious injury or fatality within SCE substations.[14]
- Moreover, the former Secretary of the Department of Homeland Security (Michael Chertoff) predicted a future attack in the U.S. that would exceed the sophistication and resulting damage of Metcalf, including the possibility of a combined physical and cyberattack.[15]

These examples illustrate the types of physical security threats this chapter evaluates. We have used the RAMP process as an opportunity to re-examine SCE's security strategy. The complexity and volume of physical threats facing SCE require an array of security mitigation measures to detect, deter, delay, disrupt, and respond to threats and hazards.[16]

Thus, SCE's controls and mitigations provide a layered approach to help ensure the safety and security of SCE workers, visitors, facilities, assets, and equipment. A layered approach refers to multiple security measures implemented at different levels throughout the facility, to help provide "pancaked" layers of protection. In other words, the perimeter is the first line of defense, the exterior of the building is the second line, and the interior of the building is the third line. A layered approach reduces the risk of unauthorized users gaining physical access to restricted areas. We describe this approach in more detail in Section V - Proposed Plan.

C. Risk Bowtie Analysis

To define and evaluate SCE's Physical Security risk, SCE has constructed a risk bowtie, as shown in Figure II-1. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

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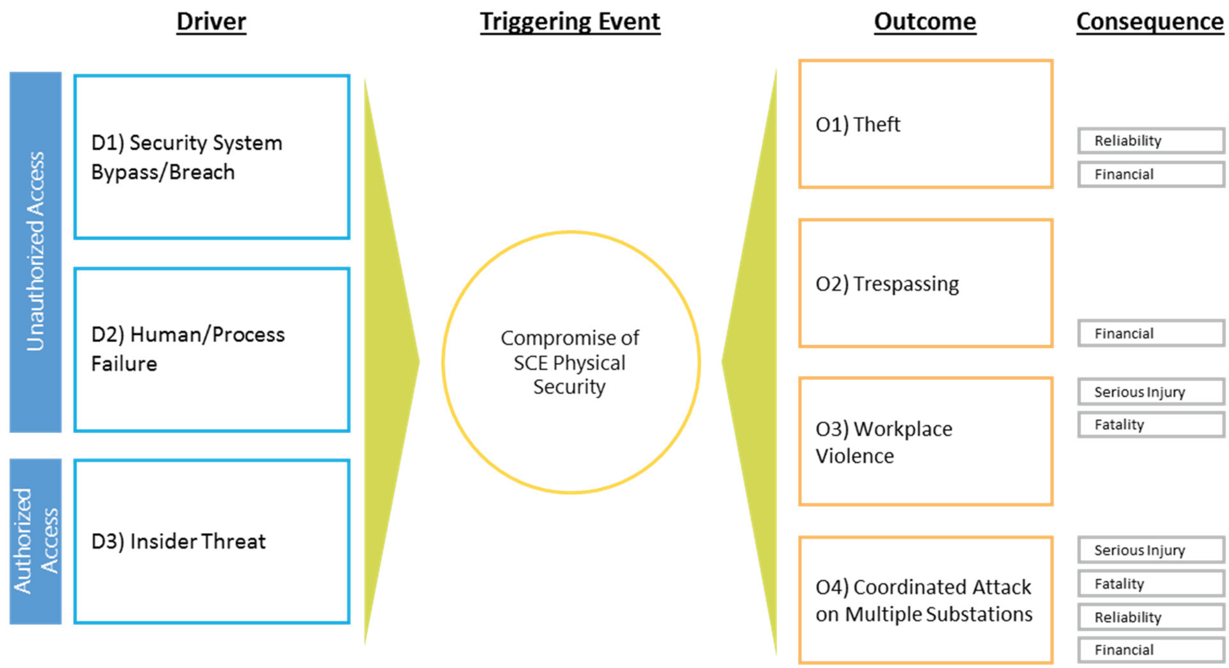
[14] 2017 CPUC Annual Report, Appendix E: 2017 Electrical Safety Incidents. Retrieved: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Annual_Reports/CPUC%20Annual%20Report%20-%20Draft%202-1-18%20-%20FINAL%20v3.pdf

[15] Michael Chertoff, "Building a Resilient Power Grid," *Electric Perspectives*, May/June 2014, p. 35.

[16] The threats that we face as a utility in one of the largest media markets and metropolitan centers in the world are significant, and those threats are continually evolving. To forecast the probability of successful breaches of our system's controls, we must make a series of educated assumptions based on what we know about our existing defenses, the demographics and capabilities of our attackers, and the growth and complexity of the physical security risk events we may face in the future.

Figure II-1 – Physical Security Risk Bowtie



D. Driver Analysis

SCE identified three drivers for this risk: D1 (Security System Bypass/Breach), D2 (Human/Process Failure), and D3 (Insider Threat). Figure II-2 shows the projected 2018 frequency count for each of these drivers.[17]

[17] Please refer to WP Ch. 9, pp. 9.1 – 9.3 *(Baseline Risk Assessment)* for further detail and evaluation of these drivers.

Figure II-2 – 2018 Projected Driver Frequency

Name	Freq	Frequency
D1 - Security System Bypass/Breach	92	
D2 - Human/Process Failure	59	
D3 - Insider Threat	1	

1. D1 – Security System Bypass/Breach

Security System Bypass/Breach is defined as an unauthorized intrusion into a secured location, accomplished by evading the security system or breaching the security perimeter. Some potential examples of Security System Bypass/Breach include:

- Intruder(s) cutting the perimeter fencing, barbed wire, and/or locks to gain entry into SCE substations, laydown yards, and facilities.
- Intruder(s) trespassing onto SCE substations, laydown yards, and facilities by climbing over or crawling under perimeter fencing.

Potential motives for Security System Bypass/Breach generally include:

- Stealing SCE or personal property (e.g. copper, tools, and/or equipment).
- Establishing a homeless encampment.
- Intending to commit acts of sabotage or work place violence.

SCE estimates an annual frequency of 92 incidents related to Security System Bypass/Breach. This estimate was derived by analyzing actual incidents from SCE's internal incident database for 2016-2017, and other external data, such as Federal Bureau of Investigation (FBI) active shooter incident data.[18]

[18] United States FBI File Repository: Active Shooter Incidents 2000-2017. https://www.fbi.gov/file-repository/active-shooter-incidents-2000-2017.pdf. Fortunately, high-impact events such as sabotage and workplace violence are rare events. In order to help predict the probability of occurrence for these events, SCE used FBI data in combination with internal data to create a larger sample size of data to model. Please note that external data was scaled down to SCE population; this allows SCE to develop a distribution based on a higher number of data points.

2. D2 – Human/Process Failure

This driver considers the failure of an SCE worker to follow policies, procedures, or protocols, or the absence of adequate processes in place that address physical security vulnerabilities. Some examples of Human/Process Failure include:

- SCE workers leaving company-issued and/or personal electronic equipment (e.g., laptops and cell phones) unattended and unlocked, resulting in the item being stolen.
- Lack of appropriate countermeasures to prevent person(s) from trespassing in and around substations, service centers, and other facilities, resulting in potential acts of sabotage or workplace violence.
- SCE workers (including security personnel) violating Company policy, leading to unauthorized access into a secure facility (e.g., tailgating[19] and unauthorized visitors).

SCE forecasts approximately 59 Human/Process Failure incidents in 2018. This estimate was based on SCE internal incident data and the FBI's active shooter data, scaled to SCE's service area.

3. D3 – Insider Threat

Insider Threat arises when an SCE worker uses current or previous access to facilities or insider knowledge with malicious intent. Consequently, an actual breach of security may not need to occur to commit the intended crime; the SCE worker may already have access. This driver occurs when there is an overt act that results in a physical security outcome.[20] Some examples of potential incidents that would be considered Insider Threat attacks include:

- A recently terminated employee using status and relationships to access SCE facilities and do physical harm to those inside the facility.

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[19] Tailgating: Following, or allowing someone to follow, into a Physical Security Perimeter (PSP) without appropriate authorization. NERC CIP requires that personnel without authorization into a PSP must be logged in/out and escorted.

[20] Incidents we captured that had no quantifiable outcome were reviewed and subsequently deemed to not be physical security threats within the definition used for RAMP. Accordingly, while these incidents remain as security concerns addressed within our physical security programs, they were excluded from the analysis.

- An employee using access to critical infrastructure to cause reliability incidents or widespread blackouts.
- An employee using their access to physically remove intellectual property or personally-identifying information from SCE facilities.

SCE forecasts approximately one insider threat incident per year. This estimate is based on SCE internal incident data from 2016 - 2017, a 2011 Irwindale workplace violence incident, FBI active shooter data from 2014 – 2017,[21] and publicly available external workplace violence incidents.

4. Driver Frequency Growth

A review of historical SCE data suggests a continued growth in the frequency of the triggering event. Additionally, other factors, such as the nationwide increase in attacks on utilities,[22] the success of attacks on the electrical infrastructure in other countries,[23] the availability of online documentation to support an attack, and the impact that an attack may have on a major media market like Southern California, are all indicators of an increased growth in physical security threats. SCE used internal data from 2013-2017 to determine growth rate.

SCE applied an annualized growth rate (7%) to each driver to illustrate the upward trend of physical security incidents in the utility industry.[24] In addition, SCE forecast growth in driver frequencies absent ongoing maintenance and implementation of current controls. For example, the baseline risk for this chapter contemplates removing fixed security officers at our

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[21] FBI data was scaled down from national scope to the size of the SCE workforce. The scaling factor was determined by dividing the SCE workforce population by the U.S. workforce population of approximately 155 million. (Source: https://data.bls.gov/timeseries/LNS12000000)

[22] Attacks in the United States from 2011-2017 were analyzed by SCE security personnel. This analysis identified a growing trend in attacks over time.

[23] Parfomak, Paul W. (2014, June 17.) "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations." *Congressional Research Service.* Retrieved from https://fas.org/sgp/crs/homesec/R43604.pdf. This is a Congressional Research paper outlining the risk to HV transformers impacting the power grid, availability of information to execute such an attack, and potential impact.

[24] Please refer to WP Ch. 9, pp. 9.1 – 9.3 *(Baseline Risk Assessment).* This workpaper contains specific details on annualized growth rate calculation.

facilities, not maintaining fences, cameras and alarms any further, and performing no further maintenance on access controls.[25] The aggregate effect of this growth is shown in Table II-1.

Table II-1 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	Total
Physical Security							
Baseline	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**
Driver							
D1 - Security System Bypass/Breach	92.14	115.08	131.96	150.32	170.20	191.65	**851.34**
D2 - Human/ Process Failure	58.50	75.35	87.55	100.93	115.52	131.35	**569.19**
D3 - Insider Threat	0.68	0.81	0.92	1.03	1.14	1.27	**5.85**
Total	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**

E. Triggering Event

The triggering event for this risk bowtie is a "compromise of SCE physical security." This event occurs when the physical security perimeter is compromised by unauthorized access, or when an insider compromises SCE's physical security, resulting in an adverse outcome.

F. Outcomes

SCE identified and evaluated the following outcomes that can occur when SCE physical security has been compromised: (1) Theft, (2) Trespassing, (3) Workplace Violence, and (4) Multiple Substation Attack. The likelihood of each outcome occurring, as shown in Figure II-3, was developed by reviewing internal data (i.e., SCE's investigation database), external data (i.e., FBI data, OSHA reports), and input from experts in physical security.

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[25] In order to assess the baseline risk, we assume for the sake of example that all fixed security officers are removed from our facilities, with the exception of those officers directly associated with compliance.

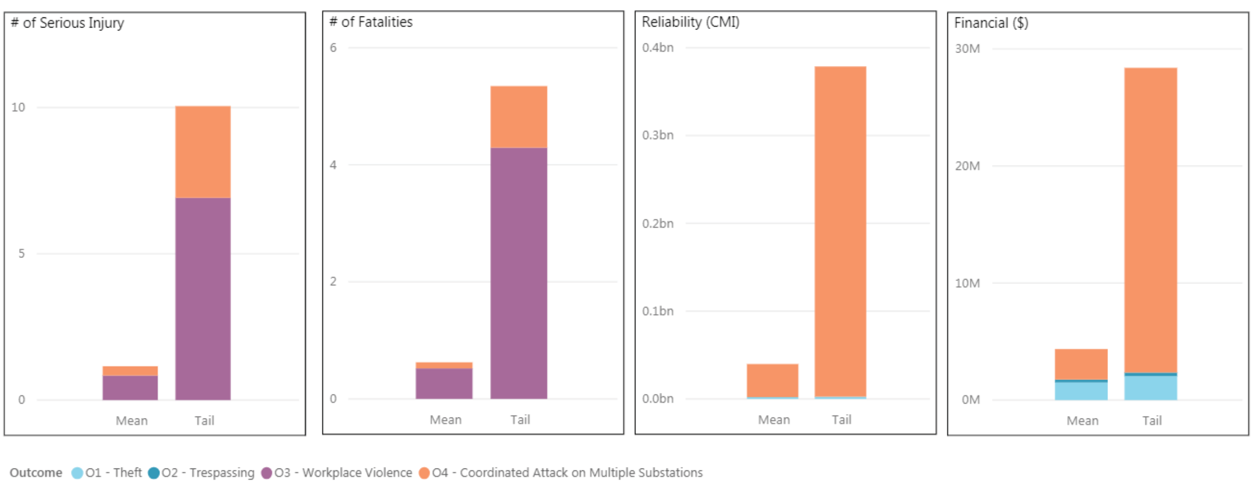
Figure II-3 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Theft	53.0 %	
O2 - Trespassing	46.9 %	
O3 - Workplace Violence	0.1 %	
O4 - Coordinated Attack on Multiple Substations	0.0 %	

Figure II-4 illustrates the composition of the modeled baseline risk in terms of each consequence dimension. This figure shows that the predominant safety impacts result from Outcome 3 (Workplace Violence), with additional safety impacts resulting from Outcome 4 (Coordinated Substation Attack).

Additionally, Outcome 4 results in the largest reliability and financial impacts of all the outcomes. The sections that follow detail the inputs used to derive these results.

Figure II-4 – Estimated Potential Consequences by Outcome



1. O1 – Theft

In this outcome, an individual steals SCE and/or personal property. Some of the most common theft incidents involve metal (copper), tools, and equipment. The most common way that intruders enter a facility is by cutting perimeter fencing or climbing over exterior fencing or walls. A real-life example took place on April 12, 2017 when two intruders cut perimeter fencing to an SCE substation and removed 15 spools of copper wire valued at $45,000.[26] SCE has experienced an increase in theft incidents from 59 in 2016 to 101 in 2017. This represents a year-over-year increase of 71%.

Metal theft incidents represent 42% of all theft incidents reported in 2017. From 2016 to 2017, SCE experienced a 115% increase in metal theft incidents (i.e., 20 to 43 respectively).

Potential consequences from O1 (Theft) are summarized on an annualized basis in Table II-2. Reliability impacts are associated with service interruptions caused by theft. Financial costs are associated with property loss due to theft. For O1, the estimate of annual impacts is 2 million customer minutes of interruption (CMI) and $1.5 million of financial harm on a mean basis; and 2.5 million CMI and $2.1 million of financial harm on a tail-average basis.

Table II-2 – Outcome 1 (Theft): Consequence Details

Outcome 1		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			Outage impacts associated with theft, SCE internal database years 2016-2017.	Financial impacts associated with theft, SCE internal data from 2016-2017.
Model Outputs *(Annual Average)*	NU - Mean			2.0M CMI	$1.5M
	NU - Tail Avg			2.5M CMI	$2.1M

2. O2 – Trespassing

Trespassing occurs when an unauthorized person(s) enters onto SCE facilities without permission. This outcome does not include incidents where the trespasser's intent was to incite one of the other outcomes (theft, workplace violence, or sabotage).

Potential consequences from trespassing are summarized on an annualized basis in Table II-3. Financial costs are associated with damage due to trespassing. For trespassing, the estimate of annual impacts is $244,000 of financial harm on a mean basis; and $306,000 of financial harm on a tail-average basis.

[26] NAVEX Case No. 2017-4-15500. NAVEX is a widely-used software tool that SCE also employs to track and manage investigative efforts and cases.

Table II-3 – Outcome 2 (Trespassing): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				Financial impacts associated with trespassing, SCE internal data from 2016-2017.
Model Outputs *(Annual Average)*	NU - Mean				$244K
	NU - Tail Avg				$306K

3. O3 – Workplace Violence

The scope for the workplace violence outcome includes incidents that could result in a serious injury and/or fatality. The U.S. Department of Labor's Occupational Safety and Health Administration (OSHA) defines workplace violence as any act or threat of physical violence, harassment, intimidation, or other threatening disruptive behavior that occurs at the work site. For purposes of this RAMP analysis, we only captured the threat of cases that resulted in serious injury or fatality.[27]

Potential consequences from workplace violence are summarized on an annualized basis in Table II-4. Serious Injury and Fatality impacts are associated with active shooter incidents. For this outcome, the estimate of annual impacts is 0.84 injuries and 0.52 fatalities on a mean basis; and 6.92 injuries and 4.29 fatalities on a tail-average basis.

[27] https://www.osha.gov/SLTC/workplaceviolence/ This is a Department of Labor summary of workplace violence statistics.

Table II-4 – Outcome 3 (Workplace Violence): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Serious injury associated with active shooter, based on 2011 internal data and 2014-2017 FBI data.	Fatality associated with active shooter, based on 2011 internal data and 2014-2017 FBI data.		
Model Outputs (*Annual Average)*	NU - Mean	0.84	0.52		
	NU - Tail Avg	6.92	4.29		

4. O4 – Coordinated Attack on Multiple Substations

This outcome results in a coordinated attack on multiple substations. This could impact the bulk electric system on a widespread basis, with consequences including serious injuries, fatalities, reliability, and financial. According to the Congressional Research Service,[28] a coordinated and simultaneous attack on substations would be catastrophic, with severe implications over a large geographic area and extended blackouts.[29] Fortunately, such an attack has not occurred in the United States to date. However, an attack is possible in SCE's service territory, given:

- The increased frequency of sabotage attempts in the United States between 2011 and 2017 (e.g., the 2013 Metcalf Substation attack, the 2013 500kV substation attack in Lonoke County, and others);
- The increasing availability of online documentation and information that can aid in planning and supporting an attack;[30]

[28] The Congressional Research Service (CRS) works exclusively for the United States Congress, developing policy and legal analysis to members of the House and Senate, regardless of party affiliation

[29] Parfomak, Paul. "Physical Security of the U.S. Power Grid: High Voltage Transformer Substations." June 17, 2014. Page 6 https://fas.org/sgp/crs/homesec/R43604.pdf This article discusses the implications of an attack on HV transformers and potential catastrophic impacts to the economy and health/welfare of society.

[30] National Academies Press. (2012) Terrorism and the Electric Power Delivery System, "Physical Security Considerations for the Electric Power Systems", Chapter 3, p. 32. Retrieved from https://www.nap.edu/read/12050/chapter/5

- Los Angeles, as a service area, comprises a high density of customers to geographic areas, headquarters a great deal of the media/entertainment industry, and has a very high profile in the news. Thus, an attack in Los Angeles will be a much more reported-upon event and will provide the attackers with relatively higher visibility.

Accordingly, SCE (with support from our SMEs)[31] developed a scenario that is analogous to the scenarios in NERC's 2015 Grid Security Exercise – GridEx III.[32]

The result of this type of coordinated attack on multiple substations would be the loss of critical grid components, unauthorized access to substations, and serious injuries and/or deaths to employees or members of the public.[33]

Potential consequences from this outcome, coordinated attack on multiple substations, are summarized on an annualized basis in Table II-5. Serious Injury, Fatality, Reliability and Financial impacts are associated with this outcome. The estimate of annual impacts includes approximately 0.32 serious injuries, 0.10 fatalities, 37.67 million CMI, and $2.61 million on a mean basis; and 3.13 serious injuries, 1.05 fatalities, 376.11 million CMI, and $26.03 million a tail-average basis.

[31] Please refer to WP Ch. 9, pp. 9.4 – 9.5 *(Subject Matter Expert Qualifications)*. This workpaper discusses the background and experience of Subject Matter Experts.

[32] (March, 2016.) "Grid Security Exercise GridEx III Report." *North American Reliability Corporation.* Retrieved from https://www.nerc.com/pa/CI/CIPOutreach/GridEX/NERC%20GridEx%20III%20Report.pdf. This is the GridEx III exercise documentation for a multi-substation attack.

[33] As mentioned earlier in this report, we may be unable to share information beyond a certain level of detail, so that we continue to protect sensitive physical security information and protocols.

Table II-5 – Outcome 4 (Coordinated Attack on Multiple Substations): Consequence Details

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE evaluated a potential physical attack scenario where an adversary obtains control of our grid assets and causes physical damage to, or destruction of, the electrical system. This scenario is a hypothetical scenario of a coordinated attack on multiple substations.			
Model Outputs	NU - Mean	0.32	0.10	37.67M CMI	$2.61M
	NU - Tail Avg	3.13	1.05	376.11M CMI	$26.03M

III. Compliance & Controls

SCE has controls in place to minimize the physical security risk that exists across SCE's facilities. These controls are scoped to protect facility classes within SCE's facility portfolio, including: electric facilities (substations), generation facilities, and non-electric facilities (office buildings, warehouses, service centers, etc.).[34] Because not every facility addressed in these controls will have the same risk exposure, the actual set of physical security measures at each facility may vary. Hence, similar to how we present physical security programs in our GRC, we present our controls on a program basis. SCE has been operating these compliance activities and controls as critical components of our layered defense protection approach for many years.[35]

Table III-1 below maps existing controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.

Table III-1 – Inventory of Compliance & Controls[36]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	NERC CIP-014	Not Modeled	Not Modeled	Not Modeled	$ 26.54	$ -
CM2	NERC V6 Low BES Sites	Not Modeled	Not Modeled	Not Modeled	$ 3.38	$ -
C1a	Grid Infrastructure Protection - Base	All	All	All	$ 11.62	$ -
C1b	Grid Infrastructure Protection - Enhanced	All	All	All		
C2	Protection of Generation Capabilities	All	All	All		
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	All	All	All	$ 10.15	$ -
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	All	All	All		
C4	Asset Protection	All	All	All	$ -	$ 25.75

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

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[34] Please refer to WP Ch. 9, pp. 9.6 – 9.20 *(Control & Mitigation Risk Reduction Effectiveness Workpaper)*

[35] Please refer to WP Ch. 9, pp. 9.21 – 9.26 *(Control or Mitigation Effectiveness Workpaper)*

[36] Recorded costs for C1 and C2 are provided in aggregate. Prior to 2018, the electric grid and generation protection programs were addressed in one program (the Electric Facilities Blanket in the 2018 GRC).

A. CM1 – NERC CIP-014

NERC CIP-014[37] was established in 2014 by NERC and approved by the Federal Energy Regulatory Commission (FERC) as a standard to protect transmission substations, and their associated primary control centers, against physical attack. NERC CIP-014 has been effective since January 26, 2015 and is a threat and vulnerability analysis to uncover potential threats, weaknesses, and corresponding risks. Under the standard, utilities must perform an initial risk assessment. This assessment must then be reviewed by an independent third party. Utilities subsequently perform a more tailored assessment and evaluation of potential threats and the associated vulnerabilities related to each identified critical location.

Finally, the utility must develop and implement a plan to protect those identified assets from physical threats, and have that plan verified by an independent third party.[38] The costs shown for CM1 represent the costs related to implementing the physical security plan under CIP-014 for that given year.

B. CM2 – NERC CIP-003-v6

On January 21, 2016, in order No. 822, FERC approved NERC CIP-003-v6[39] to establish physical security controls to protect the Low Impact BES Cyber System. These controls require policies for each Responsible Entity (e.g. SCE) to restrict physical access to our BES facilities based on need as determined by the Responsible Entity.

C. C1 – Grid Infrastructure Protection

Grid Infrastructure Protection[40] is an existing program that helps secure SCE's electric facilities against physical threats. These facilities primarily consist of substations and their

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[37] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-2.pdf. This document defines NERC CIP requirements.

[38] http://www.electricenergyonline.com/energy/magazine/813/article/Utility-Security-Understanding-NERC-CIP-014-Requirements-and-Their-Impact.htm. History of physical protection of power grid and specific NERC-CIP requirements.

[39] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-003-6.pdf. This is a write up of the specific CIP-003-6 — Cyber Security — Security Management Controls.

[40] This control was presented in SCE's 2018 GRC as part of the "Electric Facilities Blanket." See A.16-09-001, SCE's Test Year 2018 GRC, Exhibit SCE-07, Vol. 5, p. 43.

respective control centers. This control is deployed based on the criticality of need and the potential impact of a breach. Criticality is defined by assessing the amount of load served, the number of network connection points, and other factors for each substation. These factors are then used to tranche the substations into tiers: Tier 1 accounts for the most critical electrical facilities; Tier 4 is the least critical.

Through this control, SCE deploys various physical security measures that combine to actively deter, detect, delay, and deny threats using a layered defense approach. These measures can include a suitable combination of access control, alarms, perimeter protection (e.g., fencing, walls, barbed wire, etc.), video surveillance, and other measures. SCE continuously assesses the threat landscape and modifies the security measures for each substation accordingly. For example, when a facility has been identified as being a prime target of copper thieves, we arrange to install enhanced fencing to deter thieves from cutting or climbing the fencing.

SCE contemplated two options for deploying this control over the 2018-2023 RAMP period:

1. Control Options

a. C1a – Base Option

The Base option (C1a) will continue the deployment, scope, and features of the existing controls in place at electrical facilities. These activities include, but are not limited to, the following:

- Upgrading fencing;
- Improving lighting;
- Updating the processes to identify facilities requiring improved monitoring by a combination of security cameras and other technology;
- Detecting criminal activity that results in deploying uniformed security officers; and,
- Improving access management and control processes.

b. C1b – Enhanced Option

The Enhanced option (C1b) includes all measures identified in the Base option (C1a), but also includes improvements in managing and controlling access. These enhancements include tamper-resistant gate motors and hardware, and perimeter video analytics. The enhancements also encompass enhanced visitor/access management technology that replaces rudimentary paper logs with an automated system that efficiently logs, tracks, and manages visitors.

2. Drivers Impacted

Both options for this control (C1a and C1b) will impact all drivers. For example, physical barriers such as walls and gates, as well as video surveillance and/or improved lighting, can reduce the frequency of D1 (System Security Breach/Bypass). Updating security processes and access management systems can reduce the frequency of D2 (Human/Process Failure). Access restrictions for employees can reduce the frequency of D3 (Insider Threat) by granting access to only those areas where the employee specifically needs access to accomplish job duties.

3. Outcomes and Consequences Impacted

Both options for this control (C1a and C1b) will impact all outcomes. For example, the early detection and mitigation of suspicious and criminal activity in and around facilities is improved with security cameras and other technology (e.g., gunshot detection). This aids in rapidly deploying security officers and law enforcement, thereby reducing the consequences associated with all outcomes. Both control options allow SCE to respond to incidents more rapidly and effectively. Furthermore, this control helps conceal the most critical assets within substations to reduce injury, theft, or damage (to the assets or associated assets).

D. C2 – Protection of Generation Capabilities

Protection of Generation Capabilities[41] is an existing control that aims to protect SCE’s generation facilities against physical threats. This control implements most of the security measures used in the Grid Infrastructure Protection control; such as access control, alarms, perimeter protection such as block wall and steel gates, and video surveillance. However, C2 tailors these measures to fit the specific generation assets’ environment and landscape.[42] For example, our hydro facilities are often located in rural or remote areas, and the hydro

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[41] This control was presented in SCE’s 2018 GRC as the part of the “Electric Facilities Blanket.” See A.16-09-001, Exhibit SCE-07, Vol. 5, p. 43. Moving forward, it will be presented as a separate control.

[42] SCE’s Generation Portfolio includes 78 facilities.

complex[43] may cover a vast amount of territory. This control can also include enhanced security measures to meet the specific and unique needs of the generation facility being protected.

1. Drivers Impacted

The physical security measures used in this control will impact all drivers. For example, this control will reduce the frequency of D1 (System Security Breach/Bypass) by making it more difficult to penetrate our security perimeter. For instance, barbed wire fencing could deter individuals from entering a hydro facility. In addition, this control reduces the frequency of D2 (Human/Process Failure) by implementing access control, which will prevent and reduce the frequency of unauthorized access. Similarly, access control also reduces the frequency of D3 (Insider Threat) by restricting access to only those employees who should have it.

2. Outcomes and Consequences Impacted

As this control deploys similar measures as C1 (Grid Infrastructure Protection), it similarly affects each outcome and consequence. The physical security measures in C2 are tailored to the needs of each generation facility, and reduce the magnitude of impact associated with each outcome by deploying early detection technologies and faster response techniques.

E. C3 – Non-Electric Facilities - Protection of Major Business Functions

This control protects SCE's non-electric facilities against physical threats.[44] Non-electric SCE facilities include the corporate general offices, service centers, business offices, call centers, data centers, and warehouses. Security fencing and gates similar to what is used in C1 (Grid Infrastructure Protection) and C2 (Protection of Generation Capabilities) may be used to protect service centers, data centers, and warehouses in industrial environments. A combination of uniformed security staff, access controls, video surveillance, and security alarms are typically used to protect corporate general offices and business offices located in urban

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[43] Hydro complexes can include tunnels, penstocks, reservoirs, etc.

[44] This control was presented in SCE's 2018 GRC as the "Non-Electric Facilities Blanket." See A.16-09-001, SCE-07, Vol. 5. p. 37.

environments. The mix of security measures deployed to each location is uniquely tailored to the functions, criticality, and security risks of each facility.

1. Control Options

a. C3a – Base Option

The Base option (C3a) is an ongoing effort to protect SCE's assets at non-electric facilities in response to rising incidents of theft, trespassing, and workplace violence. Security control measures within this base option include, but are not limited to, a maintenance program,[45] a refresh program,[46] and associated process and procedures to improve how we identify and respond to threats. This control combines physical security technologies such as access controls based on corporate identification badges, video surveillance, and security alarms.

c. C3b – Enhanced Option

The Enhanced option (C3b) includes measures identified in the Base option (C3a). But it also includes improvements to how we manage and control access, so that we can further mitigate risks to assets and personnel at non-electric facilities. A new technology for managing and controlling access would replace rudimentary paper logs with an automated system that tracks visitors and enhances access management. This would increase control and accountability in managing access for our non-electric facilities. Deploying these enhancements would first target facilities that have the highest identified risks and criticality to our service obligations.

2. Drivers Impacted

Both options for this control (C3a and C3b) will impact all drivers. For example, access control affected through uniformed security officers can reduce the frequency of D1 (Security System Bypass/Breach). Updating security processes and access management systems can reduce the frequency of D2 (Human/Process Failure). Access restrictions for employees can

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[45] The maintenance program establishes a preventive maintenance schedule for continuity of security equipment capabilities.

[46] The refresh program establishes a prudent schedule to replace security equipment.

reduce the frequency of D3 (Insider Threat) by only granting employees access to authorized and as-needed areas.

3. Outcomes and Consequences Impacted

Both options for this control (C3a and C3b) will impact all outcomes. For example, uniformed security patrols are likely to deter individuals from stealing company assets, thereby we assumed reduction in the financial consequences associated with O1 (Theft). Access control (such as using badge readers) reduces the number of unauthorized accesses; this reduction in turn reduces the number of O2 events (Trespassing). Early detection of suspicious and criminal activity in and around non-electrical facilities is improved with video surveillance and duress alarms. This aids in rapidly deploying security officers and law enforcement, thereby reducing the consequences associated with O3 (Workplace Violence) and O4 (Coordinated Attack on Multiple Substations).

F. C4 – Asset Protection - O&M

Asset Protection is an existing control that helps protect SCE workers against physical threats.

With this control, SCE is able to: 1) properly vet SCE workers before hiring via a background investigation; 2) investigate security incidents and concerns; 3) train employees on preventing workplace violence and responding safely and appropriately to active shooter incidents; 4) deploy the Threat Management Team (TMT) to assess threats to SCE workers; and, 5) employ security officers to protect facilities and respond to security threats and incidents.

1. Drivers Impacted

The physical security measures in this control are designed to impact all drivers. The frequency of drivers D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) are reduced by deploying security officers to deter violence and property crimes, observe and report security incidents, control access to facilities, and provide immediate response capability. The Insider Threat program reduces the frequency of D3 (Insider Threat) by identifying potential threats before they materialize.

2. Outcomes and Consequences Impacted

The physical security measures implemented in this control will impact all outcomes and their associated consequences. By implementing the principal components of the program

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as outlined above SCE can respond to risks and incidents more rapidly and effectively. Safety, reliability, and financial consequences will be reduced when each outcome occurs.

IV. Mitigations

Beyond the compliance and control activities described in Section III, SCE monitors and evaluates more effective ways to respond to and mitigate evolving security threats. These efforts are summarized in Table IV-1.

Table IV-1 – Inventory of Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1a	Insider Threat Program Enhancement & Information Analysis - Base	All	All	All	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	All	All	All		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	All	All	All	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites	All	All	All		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	All	All	All		X	

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report.

A. M1 – Insider Threat Program Enhancement & Information Analysis

This mitigation will improve SCE's ability to identify and respond to insider threats by implementing new processes to collect and analyze data. This program will be implemented from 2019-2023, and include the following primary components: 1) Expand the background investigation process described in C4 (Asset Protection) to include a process for evaluating SCE applicants' and contractors' online presences, including social media, as part of the selection process; and 2) Create a new internal threat intelligence, data, and analytics program to proactively mitigate insider threat against SCE workers, the Company, and/or assets.

This mitigation will include qualitatively and quantitatively analyzing potential threat events. Once identified, threats will be assessed and safeguarded against. To continuously improve, we will refine our insider threat security processes, deploy appropriate resources, and enact adequate protections to minimize any future unexpected threats.

1. Mitigation Options

SCE contemplated two options for implementing this mitigation: a Base option M1a (Insider Threat Program), and an Enhanced option M1b (Insider Threat Program).

a. M1a – Base Option

This mitigation implements a comprehensive, enterprise-wide program to protect against insider threats that could lead to: workplace violence, intellectual property theft, compromise of grid control, exposure of critical electrical infrastructure information, and physical-cyber joint vulnerabilities.

The mitigation includes the development of a new training program for all employees, risk identification and analysis, enterprise data analytics, and joint physical-cyber security measures. This program will centralize various insider threat reduction efforts from across the company to standardize efforts, reduce gaps, and improve effectiveness.

Implementing a comprehensive enterprise Insider Threat program allows us to enhance identity management, and fosters improvement in:

- Evaluating employee risk probability;
- Identifying high-risk employees;
- Developing Insider Threat metrics;
- Proactively identifying insider threats using internal resources; and,
- Strengthening employee awareness of security protocols through training and internal communications.

b. M1b – Enhanced Option

This mitigation option implements an enhanced and accelerated version of the Insider Threat program presented above (M1a). This mitigation option will primarily utilize external experts to analyze unusual behaviors or patterns that may present risks. This should allow us to reduce risks and vulnerabilities faster and more comprehensively than what our current capabilities and processes can do. Moreover, using external resources can be expanded or reduced as needed to implement this mitigation option faster than the base option.

2. Drivers Impacted

The physical security measures used for M1a and M1b will impact D3 (Insider Threat) by preventing high-risk individuals from joining the SCE workforce, and identifying and addressing existing high-risk workers before they can commit malicious acts against SCE. In addition, M1a and M1b (Insider Threat Program – Base & Enhanced) will impact drivers D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) by conducting awareness training that will help employees reduce the frequency of incidents by:

- Being alert to detect suspicious behavior from internal or external actors;
- Adopting best practices for maintaining security protections; and
- Having ongoing awareness training so that physical security procedures are reinforced on an annual basis.

3. Outcomes and Consequences Impacted

M1a and M1b will impact all outcomes. O1 (Theft) is reduced when unusual behavior patterns from internal actors are identified, investigated and ended. Financial and reliability consequences associated with O2 (Trespassing) and O4 (Coordinated Attack on Multiple Substations) events are reduced when employees are trained to detect and report suspicious behavior from potential intruders. O3 (Workplace violence) is reduced as SCE hires lower-risk workers.

B. M2, M3, M4 – Smart Key Program: Phases 1, 2, and 3

Mitigations M2, M3, and M4 implement Smart Key technology to different facilities. Smart Key technology replaces conventional locks and keys, such as those found at electric facilities, generation facilities, office buildings, etc. Smart Keys include both mechanical and electronic features, and integrate with SCE's access control system. Smart Keys[47] allow different access authorizations to be assigned to specific individuals. They are configured to have a set expiration period. This reduces the possibility of, and consequences of, unauthorized use when a key is lost or stolen.

The benefits of Smart Keys also include greater effectiveness in controlling access with a time-and-date stamped record of every use, reduced perimeter security vulnerabilities, reduced consequences of lost or stolen keys, and greater employee accountability in managing keys.

SCE considered implementing Smart Keys through three phases over the RAMP period:

- Phase 1 (M2): Approximately 130 of SCE's most critical facilities.[48]

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[47] Smart Key locks are wire-free. However, door hardware mechanisms must be compatible to be able to function. Similarly, Smart Key activation devices require IT infrastructure such as LAN connectivity and POE.

[48] Facility criticality is determined by internal business impact analyses that consider regulatory requirements, critical business functions, and impact to the bulk electric system.

- Phase 2 (M3): Approximately 800 of the remaining SCE electrical facilities are captured by this phase.
- Phase 3 (M4): Approximately 300 of SCE's non-electric facilities.

1. Drivers Impacted

The Smart Key Program (M2, M3, and M4) will impact D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) by helping prevent unauthorized access and providing greater accountability for the use of keys.

In addition, Smart Keys reduce the frequency of D3 (Insider Threat) events by limiting access permissions to only those individuals who have a justified business need. Smart keys can also detect unauthorized access attempts; such detection can alert SCE to concerning behavior that is subject to investigation and disciplinary action.

2. Outcomes and Consequences Impacted

M2, M3, and M4 will impact all outcomes and associated consequences. For example, traditional keys turn into unrestrained keys once they are reported as lost or stolen. However, Smart Keys allow us to track and control keys efficiently and effectively by disabling them or promptly removing associated access permissions.

Smart Key technology reduces potential O1 (Theft) events. It prevents and reduces O2 (Trespassing) events because access permissions are only assigned to authorized users that have a legitimate work reason for possessing access. The use of Smart Key technology reduces events related to O3 (Workplace Violence) and O4 (Coordinated Attack at Multiple Substations). This technology helps identify unusual behavior patterns in use of the Smart Key, so that SCE can investigate and end threats.

V. Proposed Plan

SCE has evaluated the risk controls and mitigations discussed in Sections III and IV, and we have developed a Proposed Plan. The controls and mitigations included in this plan are shown in Table V-1 – Proposed Plan below.

The Proposed Plan best positions SCE to address both the low-probability, high-impact physical attack risks, and the more frequent, lower-impact physical security risk events.

Table V-1 – Proposed Plan (2018-2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	2.10	0.014	8.25	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.66	0.071	6.53	0.280
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	2.14	0.029	8.39	0.112
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.88	0.014	7.39	0.056
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.17	0.795	4.75	3.227
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.65	0.178	6.55	0.707
			Total - Proposed Plan	$ 260.24	$ 127.35	10.60	0.027	41.86	0.108

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

As discussed in Section III, SCE has designed location-specific and enterprise-wide physical security controls, and is in the process of implementing these controls at our facilities in a manner that prudently addresses current risk exposure and safeguards critical facilities. These security standards and controls were developed based on: 1) examining best practices, 2) analyzing incident and industry trends, 3) obtaining input from SMEs across the company, and 4) using security risk assessments that SCE and qualified vendors performed on Company facilities. These standards, controls, and associated procedures, are deployed as part of a layered strategy to detect, deter, delay, disrupt, and respond to the threats that exist today while taking into account constraints in authorized spending.

However, SCE faces escalating threats of theft, sabotage, and workplace violence risks in the future. As such, in the Proposed Plan, SCE strengthens and expands existing physical security practices by implementing Grid Infrastructure Protection – Enhanced (C1b), Protection of Generation Capabilities (C2), Non-Electrical Facilities/Protection of Major Business Function–Enhanced (C3b), and Asset Protection (C4). In addition, SCE supplements this work with enhanced capabilities, tools, and resources to, address the potentials for low-probability / high-impact physical attacks by implementing the Insider Threat Program – Base (M1a) and Phase 1 of the Smart Key Program (M2).

B. Execution Feasibility

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities, security technology, and ongoing work. The controls chosen for the Proposed Plan either continue or enhance existing work, which SCE has been able to execute. As such, SCE believes that the Proposed Plan can feasibly be executed.

C. Affordability

The Proposed Plan costs less than Alternative Plan #1, but more than Alternative Plan #2. The Proposed Plan strikes a balance between reducing risk and increasing cost. SCE is accepting a certain level of risk by: (a) not pursuing Mitigation M1b (Insider Threat Program – Enhanced) to counteract an evolving insider threat risk, and (b) partially limiting the implementation of the Smart Key program. However, SCE believes that the Proposed Plan will adequately address the balance of physical security threats.

The Proposed Plan delivers the second highest RSE of the three mitigations plans. Alternative Plan #1 provides the highest RSE (on both a mean and tail-average basis), but costs significantly more than the Proposed Plan. SCE considered whether additional mitigation investment would yield commensurate risk reduction. We determined that the increased risk reduction came at a relatively higher cost, and that at this time the Proposed Plan as structured is the most effective and balanced plan to address this risk.

D. Other Considerations

Advances in the sophistication of physical attack threats and development of new attack methods may render current risk mitigation activities less effective. SCE will continue to proactively monitor the emergence of future threats. If we have not anticipated the evolving threat correctly, the mitigations laid out in the Proposed Plan may not be sufficient. In addition, global politics and conflict can potentially lead to increased volume and sophistication of attacks on our electric system.

VI. Alternative Plan #1

SCE evaluated alternative options to address this physical security risk and developed an Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018-2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	1.92	0.013	7.55	0.052
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.51	0.065	5.97	0.256
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	1.95	0.026	7.68	0.102
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.71	0.013	6.74	0.051
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	2019	2023	$ 0.70	$ 1.49	1.42	0.649	5.72	2.614
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.50	0.162	5.97	0.645
M3	Smart Key Program Phase 2 - Electrical Sites	2019	2023	$ 30.97	$ 0.11	1.16	0.037	4.70	0.151
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	2022	2023	$ 8.43	$ 0.13	1.04	0.121	3.98	0.465
			Total - Alternative Plan #1	**$300.34**	**$127.60**	**12.21**	**0.029**	**48.31**	**0.113**

MARS = Multi-Attribute Risk Score

MRR = Mitigated Risk Reduction

RSE = Risk Spend Efficiency

A. Overview

Similar to the Proposed Plan, Alternative Plan #1 continues to deploy SCE's layered physical security approach. This plan then adds significant incremental resources to protect against Insider Threats and accelerates deploying Smart Keys and visitor access controls across the enterprise.

B. Execution feasibility

This plan would be more difficult than the Proposed Plan to implement due to the amount of resources required to rapidly deploy Smart Key technology to approximately 1,230 facilities over a shorter period of time. This deployment plan not only requires incremental resources to perform the Smart Key retrofits, but also a coordinated team of internal resources to integrate the new data and processes into our back-office systems, train personnel across all of these locations, and implement new processes and procedures for the use and disposition of Smart Keys.

Due to the aggressive scope and pace of this deployment, our ability to do a scaled field placement to test the technology and the business response to it would be limited. At this time, SCE believes that a more balanced approach for deploying this technology would allow benefits to be achieved at our more critical locations in short order, while permitting us to further evaluate this technology and deploy it to the balance of our locations over time.

C. Affordability

This plan presents the largest scope of work to increase our physical security protection. Not surprisingly it appears that it would reduce the most risk of the three mitigation plans. However, this is also the most expensive plan of the three.

Alternative Plan #1 has the highest RSE of the three plans. After further considering the various operational factors and cost implications of this plan, we determined that a more balanced approach to rolling out the new Smart Key technology would provide near-term benefits at a pace that would not unduly constrain the limited financial and human resources available.

D. Other Considerations

The same additional considerations raised in the Proposed Plan apply to Alternative Plan #1.

VII. Alternative Plan #2

SCE evaluated another alternative option to address this physical security risk, as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018-2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	**Name**	**Start Date**	**End Date**	**Capital**	**O&M**	**MRR**	**RSE**	**MRR**	**RSE**
C1a	Grid Infrastructure Protection - Base	2018	2023	$ 109.67	$ 0.60	1.62	0.015	6.34	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.84	0.079	7.24	0.310
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	2018	2023	$ 59.37	$ 0.60	1.56	0.026	6.08	0.101
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	2.08	0.016	8.22	0.062
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.29	0.876	5.26	3.573
			Total - Alternative #2	**$201.57**	**$126.60**	**8.39**	**0.026**	**33.14**	**0.101**

A. Overview

Alternative Plan #2 continues to deploy SCE's layered physical security strategy, albeit at a less expansive level than the Proposed Plan. This plan maintains the pace of deploying existing controls by implementing Grid Infrastructure Protection – Base (C1a), Protection of Generation Capabilities (C2), Non-Electrical Facilities/Protection of Major Business Function – Base (C3a), and Asset Protection (C4). Alternative Plan #2 will address fewer facilities over the RAMP period, relative to the Proposed Plan. Alternative Plan #2 also adds modest incremental resources to protect against insider threat risk, Insider Threat Program – Base (M1a).

Contrary to the Proposed and Alternative Plan #1, this plan does not mitigate any risk associated with lost or stolen keys, nor the security perimeter vulnerabilities related to traditional locks and keys. Furthermore, Alternative Plan #2 does not prepare SCE for a low-probability, but high-impact attack as effectively as the Proposed Plan or the Alternate Plan #1. Alternative Plan #2 addresses risks at a slower pace compared to the Proposed Plan; this will potentially expose SCE to a larger number of outcomes and associated consequences.

B. Execution Feasibility

Alternative Plan #2 represents a reduced scope of work for three major control and mitigation programs (C1a, C3a, M1a) relative to the Proposed Plan. Accordingly, as SCE believes the Proposed Plan is fully executable, this plan should likewise be feasible to execute.

C. Affordability

This plan is the least-cost option. However, it provides the lowest RSE of the three mitigation plans.

D. Other Considerations

The same additional considerations raised in the Proposed Plan apply to Alternative Plan #2.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

This first RAMP report gave us valuable insight into how we track data to quantify the physical security risk bowtie. Existing systems to track incident data meet our current operational needs. However, SCE learned that the existing systems did not entirely support how SCE modeled the physical security risk in this RAMP report. As such, SCE will consider modifying or augmenting the tracking and reporting capabilities of current systems so that we can continue to improve and refine our evaluation of this RAMP risk. This may involve developing a more centralized, cross-functional incident management database. Such a database would allow future quantitative risk analyses to comprehensively view SCE's physical security landscape, tie risk drivers to risk outcomes, and examine the associated safety, reliability, and financial consequences. A comprehensive database will allow SCE to better use a probabilistic/predictive approach to identify potential threats and obtain a greater understanding of potential trends or areas that we must focus on.

In addition to the fundamental physical security measures employed by SCE (e.g., fencing, lighting, security officers, etc.), the RAMP risk analysis helped confirm that the Company should diligently consider new mitigation options as technology improves and evolves to best address this risk (e.g. facial recognition software, personal identification technology, systems to identify gunshots and their direction of travel, etc.).

B. Data Collection & Availability

Obtaining data to quantify the risk bowtie elements was time-consuming because of the way that we track incidents currently. Further, some elements of the bowtie have very limited historical data, and we had to rely on industry and government data (scaled to SCE's level of exposure).

Ideally, a standard security report management system could be created that gives SCE a comprehensive view of our physical security landscape and risk. This would allow us to more efficiently evaluate physical security risks, and let us more quickly quantify risk drivers, risk events, risk outcomes, and associated consequences.

Further, while low-probability, high-impact incidents (e.g., sabotage and workplace violence) are fortunately limited, these are some of the higher-priority physical security concerns. Historical data related to these events is limited. The limited data set presents a challenge when populating inputs to probabilistic risk models, such as the one used for this RAMP risk analysis.

Accordingly, while the data we used in this RAMP report is the best information reasonably available, SCE will examine ways to modify existing tracking systems and reports to better inform future risk analyses.

C. Performance Metrics

SCE continues to collaborate with other utilities, industry organizations, and government entities to identify metrics that can be used to measure our physical security efforts. Internally, SCE utilizes a number of different performance metrics, including:

Table VIII-1 – Physical Security Performance Metrics

Metric	Description
Cold-Start Response Time	Cold starts are requests for security guard coverage that require immediate attention. This metric tracks the percentage of times security officers respond to (planned & immediate) cold start requests within a 4 hour timeframe.
Initial Incident Report	Short Messaging Service (SMS) is used for critical notifications and submitted to Corporate Security management for resolution. This metric tracks the percentage of initial notifications resolved within the 5 minutes of first reporting.
Security Project Milestone Adherence	Tracks project performance against scope, schedule, and cost.
Break/Fix Work Orders for Critical Facilities	Tracks the completion of break/fix notifications for critical facilities within the established period of time.

SCE will continue to use these performance metrics to mitigate physical security threats. Additional metrics we are considering for implementing in the future are:

- Electrical service interruption: cumulative customer-minutes interruption (CMI) caused by physical security incidents
- Time of recovery from outages caused by physical security incidents
- Cost of recovery from outages caused by physical security incidents
- Number of incidents associated with copper theft by geographic area
- Number of false or nuisance alarms

- Number of malfunctions of security equipment
- Number of incidents associated to vandalism, graffiti, or homelessness by geographic area

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Wildfire

Chapter 10

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

Southern California Edison (SCE) provides electric service to over five million customers in a 50,000 square-mile service area. Approximately 35% of this service territory is in High Fire Risk Areas (HFRA).[1] This chapter will address the risk of wildfire ignitions associated with SCE workers and assets. To perform this risk analysis, SCE developed a risk bowtie that includes risk drivers, triggering events, outcomes, and consequences. SCE also quantified the potential safety, reliability, and financial impacts resulting from this risk.

Wildfire mitigation measures have long been integral to our operational practices. SCE has several current controls in place that include, but are not limited to: our Vegetation Management Program, our Overhead Conductor Program (OCP), operational procedures (such as recloser blocking), and the recently introduced ester fluid-insulated Overhead Transformers. These programs help reduce the frequency or the impacts of wildfires.

SCE has evaluated existing controls and potential new mitigations to address this risk, and we have developed a Proposed Plan and two Alternative Plans. The Proposed Plan includes a portfolio of work that balances risk mitigation, execution feasibility, and cost-effectiveness. The plan leverages our existing controls, and includes new and expanded mitigations designed to reduce the risk of wildfires. Finally, as discussed throughout this chapter, this Proposed Plan aligns with SCE's Grid Safety and Resiliency Program (GS&RP) Application, A.18-09-002.

B. Scope

The scope of this chapter is defined in Table I-1.

Table I-1 – Scope of Chapter

In Scope	Ignition associated with SCE Overhead Distribution Equipment
Out of Scope	Ignition associated with SCE Transmission/Substation Equipment,[2] Ignitions not associated with SCE.

[1] The term "High Fire Risk Areas" refers to the locations in SCE's service territory that have been given a Tier 2 or Tier 3 designation in the most recent CPUC High Fire Threat District maps (CPUC Fire Maps). See D.17-12-024. The term also encompasses any additional locations that SCE had previously identified in its service area as high fire risk areas prior to the release of the most recent CPUC Fire Maps.

[2] In this chapter, SCE focuses on risks associated with SCE's distribution equipment because approximately 90 percent of all of the fires associated with electrical equipment in SCE's service area are related to distribution level voltages (33kV and below). However, some of the mitigation measures

C. Summary Results

Table I-2 summarizes the controls and mitigations included in this chapter, as well as the results of SCE's risk evaluation using SCE's Multi Attribute Risk Scoring (MARS) framework. As discussed in more detail below, the table shows that the MRR and RSE of the Proposed Plan is comparable to Alternative Plan #1 when examined in terms of mean results. The Proposed Plan has a higher MRR and a lower RSE than Alternative Plan #1 when examined in terms of tail average results.

This table also shows that the Proposed Plan has a lower MRR and a higher RSE than Alternative Plan #2 in terms of both mean and tail average results.

SCE discusses in detail in Sections V, VI, and VII the reasons why we recommend the Proposed Plan at this time, rather than Alternative Plan #1 or Alternative Plan #2.

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discussed in this Chapter will reduce fire risk for transmission facilities as well. These include, for example, situational awareness mitigation measures including HD cameras, weather stations, and advanced weather models (M7). SCE qualitatively discusses some direct safety risks associated with transmission and substation facilities in Appendix B of the RAMP Report. Going forward, SCE intends to perform more detailed quantitative analysis of transmission-related wildfire risks in future analyses.

SOUTHERN CALIFORNIA EDISON
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Table I-2 – Summary Results (Annual Average over 2018-2023)[3]

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Overhead Conductor Program (Bare + Covered)	x		x
C1a	Overhead Conductor Program - (Bare Only)		x	
C2	FR3 Overhead Distribution Transformer	x	x	x
M1	Wildfire Covered Conductor Program	x		
M1a	Wildfire Covered Conductor Program (including covered and bare sections)		x	
M1b	Underground Conversion			x
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	x	x	x
M3	PSPS Protocol and Support Functions	x	x	x
M4	Infrared Inspection Program	x	x	x
M5	Expanded Vegetation Management	x	x	x
M6	Microgrids			x
M7	Enhanced Situational Awareness	x	x	x
M8	Fusing Mitigation	x	x	x
M9	Fire Resistant Poles (M1 Scope)	x		
M9a	Fire Resistant Poles (M1a Scope)		x	
M9b	Fire Resistant Poles (M1b Scope)			x
Mean (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	6.9	6.9	6.9
	Risk Reduction (MRR)	1.3	1.2	1.3
	Remaining Risk	5.6	5.7	5.6
	Risk Spend Efficiency (RSE)	0.0037	0.0039	0.0013
Tail Average (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	24.0	24.0	24.0
	Risk Reduction (MRR)	4.3	4.1	4.3
	Remaining Risk	19.7	19.9	19.7
	Risk Spend Efficiency (RSE)	0.0126	0.0134	0.0042

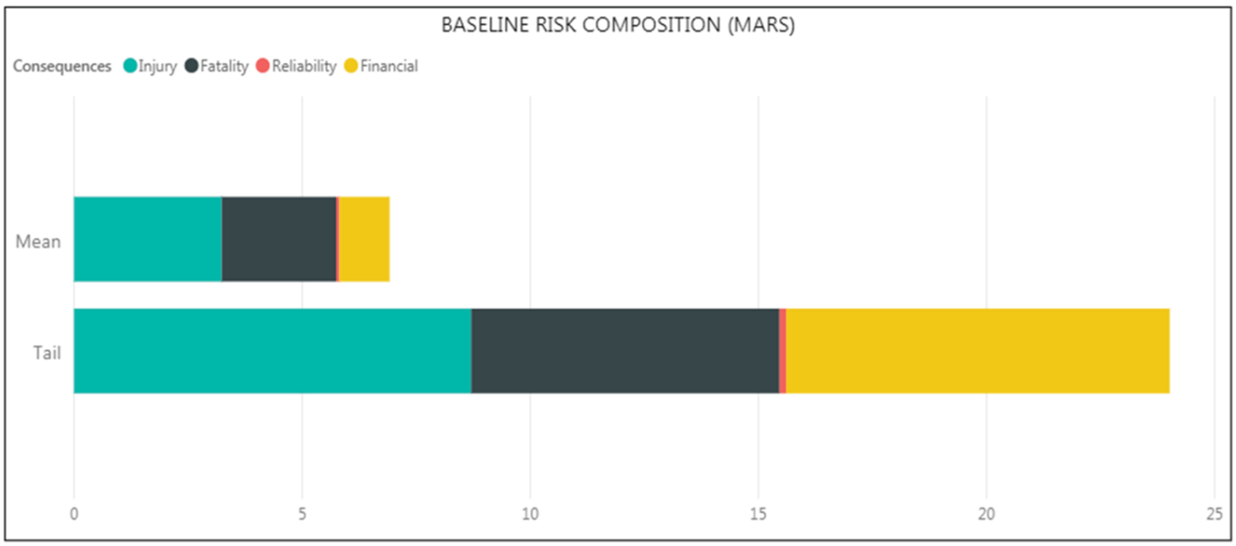
CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

[3] The OCP controls (C1 and C1a) represent a small share of the conductor-related controls in the HFRA when considering the Wildfire Covered Conductor Program mitigations (M1, M1a and, M1b). In all three of the portfolios, the control is 9% of the total conductor-related scope.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 illustrates the baseline risk associated with Wildfire. The mean result is the average result across all simulations. The tail result is the average of the most extreme ten percent of simulations. In other words, the tail indicates lower-probability, higher-impact events. The color coding represents the contribution from each of the risk attributes analyzed in this RAMP report. This figure shows that safety (serious injuries and fatalities) constitutes the largest impact on both a mean and a tail-average basis. However, financial impacts become considerably more significant when evaluating this risk on a tail-average basis.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

California is experiencing a sharp increase in the size of wildfires and the damage they cause. Unfortunately, 2017 was an historic year for wildfires in our state. Within SCE's service area, the Thomas Fire,[4] which occurred in December 2017, became the eighth most destructive wildfire in California since the early 1900s. Outside of SCE's service area, the Tubbs Fire[5] in October 2017 was notable for the number of fatalities and the time of year. As we moved into 2018, the Mendocino Complex fire,[6] which began in July of 2018, became the largest fire in California's history.

These three fires are examples of the increasing size and devastation of wildfires in California. In addition, the wildfire season has expanded to be a "year-round" fire season in California, constituting a "new normal."[7, 8]

Several factors contribute to the risk of wildfire and its consequences, including but not limited to an increase in construction in California's wilderness-urban interface areas, and the effects of climate change. The construction increase, primarily residential, expands the potential damage to property and loss of life due to wildfires. Nearly 35% of wildfires begin in this high-risk wildland-urban interface[9] where the risk of property damage and fatalities is greatest.

California's weather conditions are changing. Drought conditions have become more severe, and their durations are getting longer;[10] non-drought conditions are becoming shorter.

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[4] The Thomas Fire burned 281,893 acres between December 4, 2017 and January 12, 2018 destroying 1,063 structures, damaging 280 structures, injuring two firefighters, and causing two fatalities.
[5] The Tubbs Fire burned 36,807 acres between October 8, 2017 and October 31, 2017 destroying 5,643 structures, injuring one individual and causing 22 fatalities.
[6] As of September 5, 2018, the Mendocino Complex fire burned 459,123 acres, destroyed 280 structures, and caused 3 injuries and 1 fatality, in Northern California.
[7] Quote from Governor Edmund G. Brown's news conference on December 9, 2017 at the Ventura County Fairgrounds, after his tour of the fire areas.
[8] Marissa Clifford, *In California, It's Always Fire Season Now*, LA CURBED (June, 2018), *available at* https://la.curbed.com/2018/6/5/17428734/wildfires-calfornia-risk-prediction .
[9] Article gives further insight into wildfires started in the Wildland-urban interface. Schoennagel, Tania; Balch, Jennifer K.; Brenkert-Smith, Hannah; Dennison, Philip E.; Harvey, Brian J.; Krawchuk, Meg A.; Mietkiewicz, Nathan; Morgan, Penelope; Moritz, Max A. (2017-05-02). "Adapt to more wildfire in western North American forests as climate changes." *Proceedings of the National Academy of Sciences*. **114** (18): 4582–4590. http://www.pnas.org/content/114/18/4582.
[10] Scott Stephens et al., Drought, Tree Mortality, and Wildfire in Forests Adapted to Frequent Fire, 68

For example, severe drought conditions led to Governor Brown proclaiming a State of Emergency on January 17, 2014; Governor Brown "directed state officials to take all necessary actions to prepare for the drought conditions."[11] On April 25, 2015, Governor Brown issued Executive Order B-29-15 that proclaimed a Continued State of Emergency and, among other things, ordered significant water conservation measures. Weather conditions, such as those that propagate drought conditions, are contributing to the increase in the number of days California is under extreme fire danger and to our state facing a year-round fire season with constant wildfire risk.[12]

The Commission has addressed wildfire risk, and the risks from wildfires associated with utility infrastructure, in Rulemaking R.15-05-006. The Commission has approved revised fire threat maps and increased inspection and vegetation management requirements in these areas. Beyond these efforts, SCE is proposing additional measures to harden and upgrade our system to further prevent utility-associated wildfires and to further mitigate system impacts when a fire occurs. These measures are included in SCE's GS&RP Application.

The risk analysis presented in this chapter aligns with the GS&RP filing.[13] Both filings utilize similar underlying data and assumptions regarding risk drivers and mitigation effectiveness. This RAMP chapter quantifies the risk reduction benefits of mitigations in the GS&RP portfolio. However, there are necessarily certain inherent differences in analysis methodologies. Generally speaking, these differences occur because:

- Costs in RAMP are represented in nominal dollars, while the costs in the GS&RP filing are represented in 2018 constant dollars. This will create a variance in total forecast. However, the underlying scope identified for the various mitigations for specific time periods will be the same.
- RAMP requires considering the forecast period of 2018-2023. The GS&RP application is intended to justify the program from the filing date of 9/10/2018 through year-

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BIOSCIENCE 77, 78 (Feb. 2018), available at https://www.fs.fed.us/psw/publications/fettig/psw_2018_fettig002_stephens.pdf

[11] Governor Brown's State of Emergency Proclamation, January 17, 2014, *available at* https://www.gov.ca.gov/2014/01/17/news18368/.
[12] See Chapter 12, Climate Change for more details.
[13] For a detailed discussion on the alignment between RAMP and the GS&RP riling, please refer to WP Ch. 10, pp. 10.47-10.51 *(RAMP to GSRP Comparison Workpaper).*

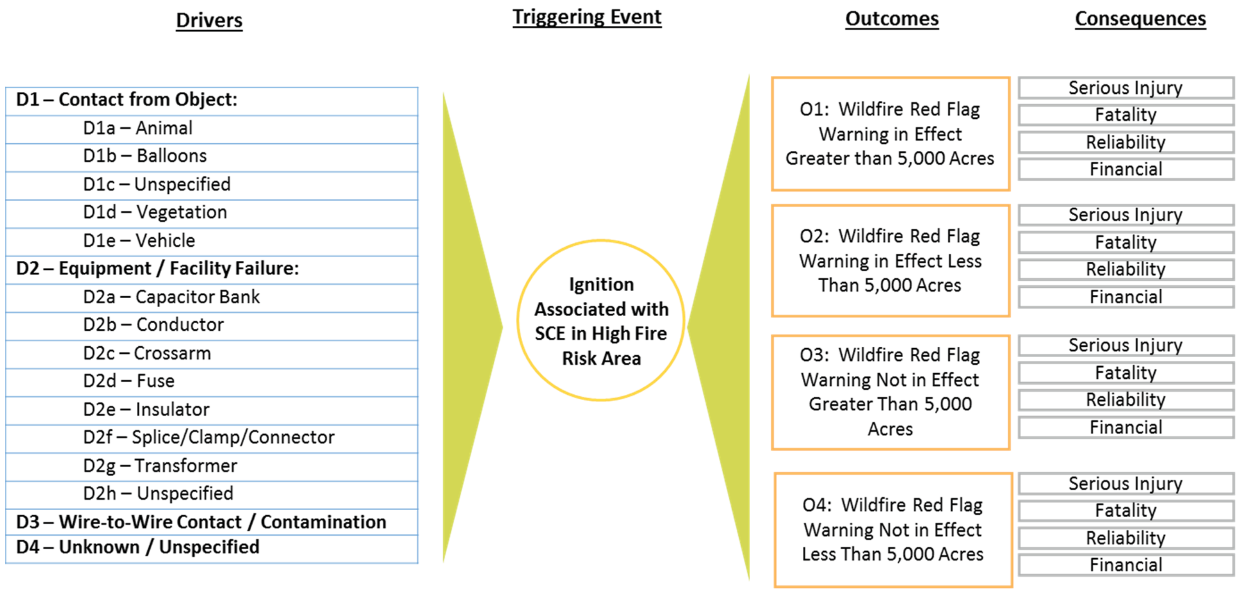
end 2020. This drives a difference in start and end dates for both filings, and necessarily causes the forecasts to vary.

- The RAMP analysis only counts benefits that occur during 2018-2023, while GS&RP considers benefits for all future years. In section V below, we discuss in greater detail the difference in benefits when the long-term benefits are included, compared to restricting the benefits period to years 2018-2023.
- The proposed RAMP portfolio excludes Wildfire Mitigation Program Study Costs. These costs are intended to allow SCE to explore new technologies to reduce future risk.
- The wildfire risk model SCE developed for RAMP evaluates wildfire events based on size ("more than" or "less than or equal to" 5,000 acres) and whether the wildfire event occurs on days when a Red Flag Warning[14] was either "in effect" or "not in effect." The GS&RP conductor-based comparative analysis does not distinguish between these differences.

Figure II-1 below summarizes the risk bowtie that SCE used to model wildfire risk in this chapter.

[14] Red Flag Warning is a term used by fire-weather forecasters to call attention to limited weather conditions of particular importance that may result in extreme burning conditions. It is issued when it is an ongoing event, or when the fire weather forecaster has a high degree of confidence that Red Flag criteria will occur within 24 hours of issuance. Red Flag criteria occurs whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, and the National Fire Danger Rating System (NFRDS) is high to extreme and the following forecast weather parameters are forecast to be met: 1) a sustained wind average 15 mph or greater; 2) relative humidity less than or equal to 25 percent; and 3) a temperature of greater than 75 degrees F. In some states, dry lightning and unstable air are criteria. A Fire Weather Watch, for conditions that may exist within 12-72 hours, may be issued prior to the Red Flag Warning.

Figure II-1 – Risk Bowtie



B. Driver Analysis

To identify the drivers that caused the triggering event (ignition associated with SCE in High Fire Risk Area), SCE analyzed the fires that occurred in SCE's service area between 2015 and 2017 that were reportable to the CPUC.[15] This analysis yielded four major categories of drivers:

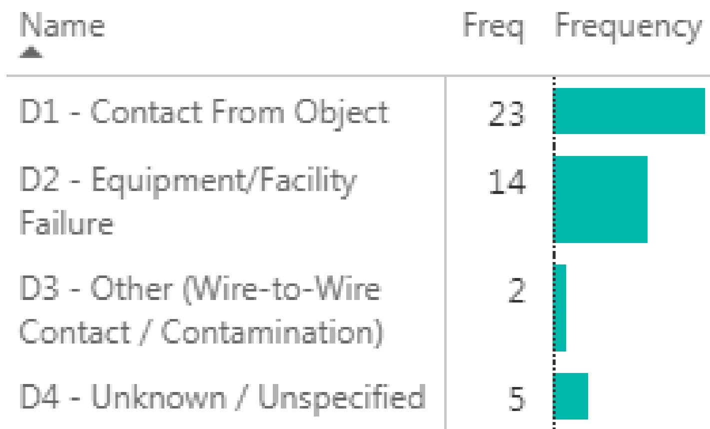
1. D1 - Contact From Object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/Facility Failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-Wire Contact/Contamination; and,
4. D4 – Unknown/Unspecified.

To develop the number of events for each driver, SCE analyzed the ignition events identified above to exclude events that did not occur in HFRA. For purposes of risk modeling, SCE rounded the three-year averages for each driver to the nearest whole number. This rounding resulted in some low-frequency drivers having a three-year average of zero, and does not impact the risk analysis results. SCE identified four drivers, as shown in Figure II-2 below. As detailed below, we

[15] Per D.14-02-015, reportable fire events are any events where utility facilities are associated with the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities; (b) the resulting fire traveled greater than one linear meter from the ignition point; and (c) the utility has knowledge that the fire occurred.

were able to subdivide two of these drivers (D1 and D2). This greater granularity helped us better understand the causes of this risk.

Figure II-2 – 2018 Projected Driver Frequency[16]



SCE performed analyses that correlated fire events to faults on SCE's distribution system. These faults, which have historically occurred from all drivers and sub-drivers shown in Figure II-1, can result in arcing during the fault event. When this arcing contains sufficient energy—given local conditions such as temperature, humidity, and nearby fuel source—ignition can result and lead to a wildfire.[17] Figure II-3 illustrates how the two most prevalent categories of faults can lead to wildfires.

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[16] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

[17] The concept of fault energy can be described as the electric system's natural reaction to fault conditions. Dominant factors for fault energy are the duration and the magnitude of electrical current during a fault. In essence, reducing fault energy helps reduce the probability of ignition.

Figure II-3 – Illustrative Event Diagram for Wildfire Ignitions Originating from Faults on Overhead Circuits

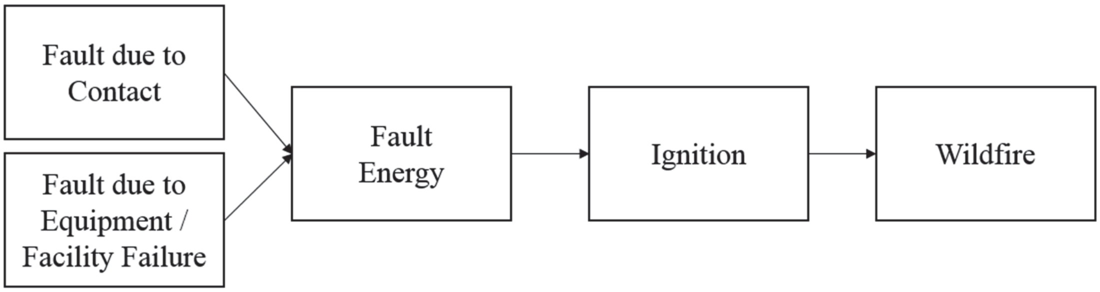

Table II-1 breaks down the different driver categories used within our risk modeling efforts. Table II-2 and Table II-3 break down the sub-drivers of Contact from Object and Equipment/Facility Failure, respectively.

Table II-1 – Driver by General Category

	Annual Count				
Suspected Initiating Event	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1 - Contact From Object	23	21	26	23	52%
D2 - Equipment / Facility Failure	10	21	9	14	32%
D3 - Other (Wire to Wire Contact / Contamination)	4	0	2	2	5%
D4 - Unknown / Unspecified	7	2	7	5	12%
Total	**44**	**44**	**44**	**44**	**100%**

Table II-2 – D1 (Contact from Object) Sub-Driver Statistics

	Annual Count				
D1 - Contact From Object	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1a - Animal	7	5	3	5	11%
D1b - Balloons	2	3	9	5	11%
D1c - Other	2	5	3	3	7%
D1d - Vegetation	8	6	8	7	16%
D1e - Vehicle	4	2	3	3	7%
Total	**23**	**21**	**26**	**23**	**52%**

Table II-3 – D2 (Equipment/Facility Failure) Sub-Driver Statistics

D2 - Equipment / Facility Failure	Annual Count 2015	2016	2017	3 Year Average (Rounded)	% Total of All Drivers
D2a - Capacitor Bank	0	1	1	1	2%
D2b - Conductor	2	8	2	4	9%
D2c - Crossarm	0	0	1	0	0%
D2d - Fuse	0	1	0	0	0%
D2e - Insulator	1	2	2	2	5%
D2f - Splice/Clamp/Connector	3	4	1	3	7%
D2g - Transformer	1	1	1	1	2%
D2h - Other	3	4	1	3	7%
Total	**10**	**21**	**9**	**14**	**32%**

As we described above in section II-B, SCE ascertained the drivers (i.e., the causes of the fire events) by analyzing the fires that occurred between 2015 and 2017 in SCE's service territory that were reportable to the Commission. The drivers and sub-drivers presented in these tables are described below.

1. D1 – Contact from Object

a. D1a – Contact from Object – Animal

Many animals come in contact with SCE's distribution facilities on a daily basis. When an animal or bird is sitting or walking on an overhead conductor, its feet are at the same voltage potential[18] and the animal or bird will not be electrocuted. However, electrocution occurs when one of the animal's feet comes into contact with an object at a different potential (such as another conductor or a grounded object like a tree) while the other foot (or feet) remains on the conductor. Electrocution results in severe injury, or death, to the animal and damage to the conductor and other electrical equipment impacted by the fault. Additionally, the remains of the animal itself can ignite and become a fire risk.

b. D1b – Contact from Object - Balloons

Foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[19] has recognized this concern, and requires that all helium-filled foil balloons be weighted, to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines it can create a short circuit. This can cause a large power arc, resulting in circuit damage, overheating, fire, or an explosion.

[18] Voltage potential is a measure of the propensity for electricity to travel from one point to another.
[19] California SB 1990, "Balloon Law."

c. D1c – Contact from Object – Other

Contact from other unspecified objects, or foreign material, include items such as tennis shoes, chains, gunshots, ice, crop dusting and other items. Each object has the potential to cause different types of failures, ranging from a fault to equipment failure, or ignition of the object itself.

d. D1d – Contact from Object – Vegetation

Even with SCE's existing vegetation management programs (see Compliance Control (CM1) – Vegetation Management in Section III), vegetation can still make contact with overhead conductor and cause an ignition and/or a wire down event. Branches or palm fronds can break or come loose from the main tree and fall, or can be blown by wind into overhead conductor. Besides causing faults, these branches and palm fronds can ignite and become additional fire risks.

Branches or palm fronds that blow into overhead conductor can come from trees in excess of 200 feet away depending on the wind and terrain. This distance is well beyond required clearances. Additionally, vegetation growth rates can vary, and trees or other vegetation may grow faster than anticipated between scheduled inspections. Vegetation can grow into lines and make contact, despite SCE's efforts to inspect and maintain clearances throughout our 50,000 square-mile area.

e. D1e – Contact from Object – Vehicle

Vehicles can come into contact with SCE poles and other aboveground equipment, resulting in damage to the pole and/or equipment.[20] Vehicle impact causes SCE's equipment to fail in many ways: conductor or other equipment falling to the ground; conductor slapping together causing a fault; or the pole falling to the ground and taking the conductor with it. Sometimes, the failure can result in a wildfire.

2. D2 – Equipment / Facility Failure

a. D2a – Equipment / Facility Failure – Capacitor Bank

SCE uses capacitor banks to compensate for reactive power losses and to regulate voltages on the distribution system. Approximately 85% of all distribution capacitor banks on the SCE system are installed on overhead circuits. Failing capacitor banks may create

[20] Although not covered in this risk analysis, SCE is sensitive to the fact that there can also be injury to the driver and damage to the vehicle.

arcing from the associated equipment, and the released electrical energy can be enough to ignite fires, either at ground level or at pole-top level.

b. D2b – Equipment/Facility Failure – Conductor

When an energized conductor fails and hits the ground, wildfire ignition can occur. In general, there are two ways overhead conductor can experience failure.

The first is when the system's short circuit duty (SCD) exceeds a conductor's rating. Generally, SCD indicates the relative strength of an electrical system, typically measured by the current (in amps) that the system can supply when fault conditions occur. If, at any given point in the system, fault current exceeds the conductor's ability to withstand it, then fault conditions can damage the conductor and lead to conductor failure. Vintage small conductor is especially vulnerable to damage during fault conditions, because it typically possesses a lower conductor rating, or current carrying capacity, compared to larger conductor.

The second is conductor fatigue. Conductor fatigue refers to the decrease in overhead conductor's ability to withstand forces experienced during operational conditions. For overhead wire, the likelihood of fatigue-related failures tends to increase over time, as the conductor is exposed to longer periods of operational stress. For example, overhead conductors have both a normal long-term thermal rating and a higher short-term emergency thermal rating. Emergency thermal ratings are used to accommodate higher levels of load. These ratings are typically relied on during abnormal operating conditions, such as when transferring customers between adjacent circuits in order to restore service as rapidly as possible during circuit outage conditions.

Beyond the operating conditions described above, the conductors could also be exposed to very high-magnitude short circuit current from time to time when there is a fault condition further downstream in the circuit. Even though these short circuit currents are typically very brief in duration, the extremely high current level can result in a rapid increase in localized temperature of the conductor. This can start to change the molecular structure of the conductor material; the result is a significant and permanent reduction in the mechanical strength of the conductor. When coupled with other induced mechanical loading such as wind, vibration, and other environmental factors, this will contribute to the conductor experiencing fatigue-related failures at some point in its lifetime.

c. D2c – Equipment/Facility Failure – Crossarm

Crossarms are mounted on distribution poles and used to support overhead conductor or other pieces of overhead distribution equipment. As crossarm pieces weaken or deteriorate over time, either the crossarm can break or the bracket that attaches the crossarm to the pole can fail. In either case, conductor can come into contact with other conductors, the pole, other pieces of electrical equipment, or the ground. This may lead to the causal fault chain shown in Figure II-3 above, with the end result being a wildfire.

d. D2d – Equipment/Facility Failure – Fuse

Fuses are protective devices designed to clear system faults by interrupting fault current and de-energizing circuits downstream of the fuse. Fuses are essentially thermal devices designed to melt at a specified current in a specified time. Fault clearing times, or the time it takes a fuse to activate, generally depend on both current and time. Faster fault clearing typically occurs for higher levels of fault current, while slower fault clearing occurs for lower levels of fault current.

When the fuse element melts, it must be able to do so without causing catastrophic failure of the fuse itself. Such fuse failures can cause prolonged fault conditions, equipment damage, or fire ignition.

e. D2e – Equipment/Facility Failure – Insulator

Insulators provide mechanical support to energized conductors and maintain electrical isolation between energized conductors and grounded structures such as poles.

Insulators can fail in various ways. For example, insulators, especially older glass or porcelain insulators, can be broken by contact from a wide range of foreign objects, from hail storms to gunshots. The mounting part of insulators that connects the insulator to the crossarm can deteriorate over time and break or come loose. The tie that connects the energized conductor to the insulator can also come loose; this can damage the conductor over time or detach completely from the conductor. In any of these cases, the insulator failure leads to loss of mechanical support for the conductor. This causes the conductor to come into prolonged contact with the pole, with other equipment, or with the ground. Any such contact can eventually lead to an ignition.

f. D2f – Equipment/Facility Failure – Splice/Clamp/Connector

Splices, clamps, and connectors are three different devices used to connect overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector or clamps. Spans of conductors are connected to other spans of conductor with a splice. These devices can degrade due to exposure to the elements, and can be damaged as the result of faults on the circuit. Faults on a circuit and the resulting fault current can cause these devices to overheat and melt, causing the overhead conductor to fall to the ground. Failures of splices can result in a conductor coming down and faulting due to contact with other equipment, objects, or the ground.

g. D2g – Equipment/Facility Failure – Transformer

Distribution transformers can fail for several reasons. One common reason for transformer failures is heavy transformer loading over extended periods of time. Such conditions cause transformers to heat up. This prolonged loading at or near the transformer's rated loading condition can also shorten the useful life of the insulation material. This increases the probability of failure. This problem is exacerbated during extended heat wave conditions, because the equipment does not have the necessary time to cool.

Historically, SCE has experienced a high number of transformer failures during heat storms. The exterior shell of the transformer can deteriorate over time and leak oil, which can also lead to failure. Moreover, because transformers contain oil, when transformers overheat they can fail violently and cause a fire.

h. D2h – Equipment/Facility Failure - Unspecified

This driver category captures wire-down events where field personnel have attributed the event to equipment failure, but the specific equipment detail is not provided.

3. D3 – Wire-to-Wire Contact / Contamination

Wire-to-wire contact can occur during high winds or during conditions where third parties make contact with poles or conductors. The factors that can contribute to wire-to-wire contact include the phase spacing, pole geometry, and conductor tension on each phase of the circuit. When wire-to-wire contact occurs, fault conditions can damage the conductor and cause conductor failure.

Contamination is a phenomenon typically associated with the insulators that support the conductor in a distribution circuit. Contamination-related flashovers typically begin when some type of airborne contaminant combines with moisture from fog, rain, or dew and collects on the surface of insulators. These contaminants can begin to conduct current across the insulators. Unless corrective action is taken, this current can cause the insulator to not perform as intended, resulting in a "flashover." Such flashovers can cause conductor or insulator damage and can lead to a wire-down.

4. D4 – Unknown / Unspecified

Unknown includes incidents where the cause was not identifiable. An example could be a fault on the system where an object made contact with a line but was subsequently blown or dispersed away from the line before SCE personnel arrived at the location.

C. Triggering Event

SCE utilized one triggering event related to wildfire risk. As shown in Figure II-1, this triggering event is "Ignition Associated with SCE in High Fire Risk Areas." This single triggering event can result from the many drivers discussed above and can lead to the outcomes and consequences described below.

D. Outcomes & Consequences

SCE identified four outcomes for the wildfire triggering event as shown in Figure II-1. These four outcomes are based on Red Flag Warnings and the size of the fire. SCE used the Red Flag Warning days because of the higher fire risk during those events and SCE's operating procedures when a Red Flag Warning is in effect within SCE's service area.

SCE also distinguished between fires greater than 5,000 acres and less than 5,000 acres. SCE used the 5,000 acre cutoff to distinguish between large fires with significant safety, financial, and reliability consequences, and smaller fires with lesser consequences. This size cutoff aligns with the largest size classifications for ignitions reported to the Commission per D.14-02-015. Additionally, SCE observed that all fires recorded by CalFire with a cause of "Electrical Power" from 2007-2017 showed recorded fatalities only for large fires greater than 5,000 acres.[21]

To show the likelihood of each outcome occurring, SCE analyzed the fires that occurred in SCE's HFRA service area between 2015 and 2017 that were reportable to the CPUC. Fire size is tracked as part of this CPUC reporting.[22] SCE analyzed meteorological data to identify which fires occurred during Red Flag Warnings. The results are shown for each individual outcome in Figure II-4 below.

[21] The California Department of Forestry and Fire Protection (CalFire) publishes an annual Wildfire Activity Statistics report, commonly known as the "Redbook."
http://www.fire.ca.gov/fire_protection/fire_protection_fire_info_redbooks

[22] For Outcome O3 – "Wildfire Red Flag Warning Not in Effect Greater than 5,000 Acres," SCE's data reported zero fires with this outcome. For analysis purposes, SCE included a 0.19% probability, based on the ratio of CalFire incidents occurring on Red Flag Days compared to non-Red Flag Days for fires greater than 5,000 acres. Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

Figure II-4 – 2018 Outcome Likelihood[23]

Name	%	Percent
O1 - Wildfire Red Flag Warning in Effect Greater than 5,000 Acres	0.8 %	
O2 - Wildfire Red Flag Warning in Effect Less Than 5,000 Acres	31.0 %	
O3 - Wildfire Red Flag Warning Not in Effect Greater Than 5,000 Acres	0.2 %	
O4 - Wildfire Red Flag Warning Not in Effect Less Than 5,000	68.1 %	

For each outcome, SCE identified applicable consequences, and modeled these consequences using statistical distributions. For many consequences modeled in this chapter, SCE developed a distribution based on CalFire's published fire statistics, with cause classifications assigned by CalFire as "Electrical Power," which is defined as "Fire ignited by electrical power distribution or transmission."[24]

Please see Chapter 2 (Risk Model Overview) for additional detail regarding the outcome and consequence distribution modeling process. The sections that follow detail the data used to inform the development of these distributions.[25]

The wildfire events included within CalFire data encompass events in SCE's service area, as well as a number of events that occurred outside our service area but within California. The CalFire data population of fires associated with Electrical Power in SCE's service is relatively small, especially for fires greater than 5,000 acres. By including events from areas outside of SCE's service area, SCE could provide a more robust wildfire risk analysis. SCE's consequence modeling utilizes this CalFire data for fatalities, structures destroyed, and acres burned.

Figure II-5 illustrates the composition of the modeled baseline risk in terms of each consequence dimension, shown in natural units, on both a mean and tail-average basis. The sections that follow examine the inputs used to derive these results. Figure II-5 shows that O1 (Red Flag Day, >5,000 Acres), accounts for most of the serious injury, fatality, and financial impacts of this risk. Conversely, O4 (Non-Red Flag Day, <5,000 Acres) accounts for the majority of reliability impacts of this risk.

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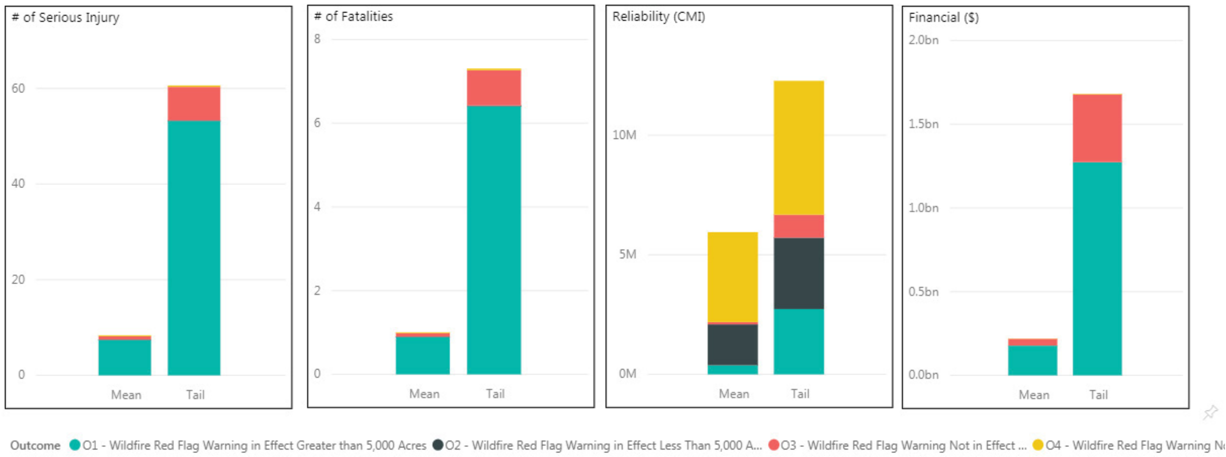
[23] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[24] http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF
[25] Note that SCE includes wildfire consequences from across California to develop these distributions, due to the relatively low number of large fires in SCE service area.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)



1. O1 – Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 0.8% of wildfire events we evaluated result in this outcome. Wildfires that occur during Red Flag Warnings have the potential to be more aggressive and faster-moving fires. This is due to environmental conditions such as low relative humidity, strong winds, dry fuels, the possibility of dry lightning strikes, or any combination of these factors. These large fires can be more dangerous to people and more destructive to property, vegetation, and wildlife.

We summarize potential consequences from O1 on an annualized basis in Table II-4.[26] Serious injuries and fatalities are associated with firefighters and members of the public that could be physically injured during a wildfire event. Financial costs are associated with property damage, firefighting costs, and land restoration costs. Reliability reflects outage events associated with fires. Consequences are shown in natural units (NU), which are defined as Serious Injuries and Fatalities for Safety, Customer Minutes of Interruption (CMI) for Reliability, and US Dollars for Financial. On a mean basis, this outcome is modeled to result in 7.4 serious injuries, 0.89 fatalities, 380,000 customer minutes of interruption, and $177 million in financial consequences. Similarly, on a tail-average basis, this outcome is modeled to result in 53.2

[26] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*), and WP Ch. 10, p. 10.52 *(SME Qualifications)* for additional detail on model inputs and rationale.

serious injuries, 6.4 fatalities, 2.7 million customer minutes of interruption, and $1.3 billion in financial consequences. The similar tables for Outcomes 2 – 4 also display this type of information for their respective consequences.

Table II-4 – Outcome 1 (Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres): Consequence Details[27,28]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	7.4	0.89	380,083	$177,046,382
	NU - Tail Avg	53.2	6.41	2,731,289	$1,272,262,531

2. O2 – Wildfire Red Flag Warning In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 31.0% of wildfire events evaluated result in this outcome. Table II-5 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

[27] As of October 19th, 2018, CalFire Redbook data had not been released for 2017. However, several significant 2017 fires have been publically reported by CalFire in news releases to be caused by Electrical Power, and included within this analysis. Please refer to Section VIII-B for additional description of data availability.

[28] http://www.usfa.fema.gov/downloads/xls/statistics/us_fire_loss_data_sets_2006-2015.xlsx

Table II-5 – Outcome 2 (Wildfire Red Flag Warning In Effect Less Than 5,000 Acres): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.1	0.01	1,709,923	$689,707
	NU - Tail Avg	0.2	0.02	2,983,897	$1,205,427

3. O3 – Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 0.2% of wildfire events evaluated result in this outcome. Table II-6 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-6 – Outcome 3 (Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres): Consequence Details

Outcome 3		Consequences			
		Serious Injury	Fatality	Reliability (CMI)	Financial
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.7	0.09	96,120	$40,484,491
	NU - Tail Avg	7.0	0.84	961,196	$404,844,913

4. O4 – Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 68.1% of wildfire events evaluated result in this outcome. Table II-7 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-7 – Outcome 4 (Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres): Consequence Details

Outcome 4		Consequences			
		Serious Injury	Fatality	Reliability (CMI)	Financial
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.2	0.02	3,760,369	$1,516,932
	NU - Tail Avg	0.3	0.04	5,596,130	$2,261,676

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III. Compliance & Controls

SCE has programs and processes in place today that serve to reduce the frequency of the risk materializing, or the impact level of a risk event should it occur. These activities are summarized in Table III-1, and discussed in more detail thereafter.

Table III-1 – Inventory Compliance & Controls[29,30,31]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$0.0	$84.3
C1	Overhead Conductor Program (Bare + Covered)	D1a, D1b, D1d, D2b, D2f	-	-	$138.7	$0.0
C1a	Overhead Conductor Program - (Bare Only)	D2b, D2f	-	-	$138.7	$0.0
C2	FR3 Overhead Distribution Transformer	D2g	-	-	$0.0	$0.0

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

A. CM1 – Vegetation Management

Vegetation Management includes pruning and removing trees that are in proximity to transmission and distribution high voltage lines. Vegetation Management also encompasses weed abatement around select overhead structures that may pose a hazard to power lines. These activities are mandated by regulation. This compliance-related work is distinct from the Expanded Vegetation Management mitigation developed and requested in the GS&RP mitigation portfolio, which although absolutely critical, is not expressly required by rule or regulation at this time. This Expanded Vegetation Management is represented in M5.

SCE manages vegetation in accordance with several regulations, including General Order (GO) 95 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. SCE engages approved contractors to trim and remove trees and weeds, and engage in other vegetation management activities that comply with these requirements.

[29] Within control and mitigation numbering, "a" and "b" designations indicate a change to a subset of overall program configurations. For example, the C1a OCP control explores the reversal of a standards change that is planned for 2020 to utilize covered conductor across all OCP scope in HFRA. M1a and M1b explore covered or bare conductor options in a subset of HFRA. 2017 recorded costs for OCP are duplicated for C1 and C1a as SCE has just one OCP program in the recorded period.
[30] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).
[31] Control C2 does not show recorded costs, since it is associated with incremental costs for a change of standard for an existing program.

All of the trees in inventory are inspected annually. During these inspections, any trees or vegetation that need to be remediated to maintain the required distances from high-voltage lines are then scheduled to be pruned or removed. In addition, hazard trees, such as overhangs in HFRA, and damaged or diseased trees are also identified for pruning or removal. Sometimes we must trim trees more frequently to continue to meet the Commission's requirements for tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle infestation or resulting from California's Drought Order. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve. The estimated number of dead trees statewide is estimated at over 129 million, with over 14 million dead trees in high-hazard zones.[32]

B. C1 and C1a – Overhead Conductor Program (OCP)

C1 and C1a contemplate the benefit of deploying SCE's OCP program in HFRA. C1 captures the benefit of deploying OCP in HFRA using covered conductor.[33]

C1 will initially leverage bare conductor from 2018-2020 and transition to covered conductor for 2021-2023. SCE implemented a standards change in July 2018 to require new OCP projects in HFRAs to use covered conductor, which will provide additional wildfire risk benefits compared to bare conductor. Standards changes are applied to all new designs initiated after the standard is published. Because standards do not apply retroactively, inflight projects at various stages of completion with operating dates as late as 2020 will be built with bare conductor in HFRAs.

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[32] Source: http://calfire.ca.gov/communications/downloads/newsreleases/2017/CAL%20FIREandU.S%20ForestAnnouce129MillionDeadTrees.pdf

[33] Please see Section IV.A for a more detailed description of covered conductor.

C1a captures the benefit of deploying OCP in HFRA using only bare conductor for the entire period 2018-2023. Covered conductor is described in more detail in Section IV – Mitigations.

In SCE's 2018 General Rate Case (GRC),[34] we proposed the OCP as a new program to address the public safety risk associated with wire-down events. SCE's OCP includes both reconductoring and installation of branch line fuses (BLFs). When OCP projects are performed in HFRA, these projects also will have wildfire risk reduction benefits as well.

Reconductoring and branch line fusing are intended to target and remedy overhead conductor susceptible to exceeding its short circuit duty rating.[35] The OCP also addresses damaged conductors using visible corrosion detection, and evaluates splice counts on the line as indicators of prior damage. As part of OCP, we also address crossarms, poles, connection hardware, and other damaged equipment along the path of the conductor being remediated.

Historically, SCE's distribution circuits were designed with larger conductor closer to the substation (feeding the circuit) and progressively smaller conductors as one proceeds further from the substation. This design approach was based on economics principles, and the fact that a circuit carries less current as it moves away from the substation.

The smaller conductor, when installed, was sized appropriately for the load. However, this smaller conductor is also inherently more susceptible damage from contact with metallic balloons, animals, vegetation, and other drivers listed in Table II-2 as the available SCD increased over time due to system upgrades. By replacing this smaller conductor with larger conductor, we reduce the risk of failure.

Installing branch line fuses protects against fault energy-related conductor failure. Fusing a line limits the amount of energy delivered to a fault. It does so by interrupting the current faster than the next upstream device, often the circuit breaker at the substation, keeping the conductor within its SCD rating. SCE's OCP includes fusing tap lines to mitigate the risk of overhead conductor failure.

[34] See SCE's Test Year 2018 GRC, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

[35] When reconductoring, SCE uses a minimum wire size of 1/0 Aluminum Conductor Steel Reinforced (ACSR), with 1/0 ACSR used predominately for tap lines, and 336 ACSR used predominately for main line sections.

1. Drivers Impacted

The OCP (C1) impacts Driver D1 (Contact from Object) with the covered conductor standards change starting in 2021,[36] and also impacts Driver D2 (Equipment Cause) for all years over the 2018-2023 RAMP period.[37] The OCP (C1a) impacts only Driver D2, for all years over the 2018-2023 RAMP period.[38]

Based on engineering analysis and demonstrated material performance, replacing small wire with large wire will increase the conductor's ability to withstand higher short circuit duty. This makes the conductor less susceptible to failure from faults on the line. Similarly, installing BLFs will reduce the risk of failure by quickly interrupting the flow of current when fault conditions are present.

Reconductoring with bare wire *will not* reduce the frequency of contact from object faults. Contact from objects are external, or random, events that will continue to occur regardless. However, reconductoring with covered conductor *will* reduce the frequency of contact from object faults.

2. Outcomes & Consequences Impacted

The OCP (C1 and C1a) will not directly impact outcomes or consequences in the risk model.

C. C2 – Ester Fluid (FR3) Overhead Distribution Transformer

This control will replace existing overhead distribution transformers (which are primarily filled with mineral oil) with overhead distribution transformers filled with ester fluid. Envirotemp FR3 Fluid, or ester fluid, is a derivative of renewable vegetable oil, and has a higher flash point rating than mineral oil.[39] This decreases the likelihood that the fluid and/or fluid vapors will ignite and stay lit during a catastrophic event. This in turn reduces the chance of igniting surrounding brush and/or other flammable material surrounding the pole and transformer.

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[36] The specific sub-drivers impacted include D1a (Contact From Object – Animal), D1b (Contact From Object – Balloons), and D1d (Contact From Object – Vegetation).

[37] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

[38] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

[39] According to Safety Data Sheets, Petroleum Electrical Insulating Oil (or transformer mineral-oil) has a Cleveland Open-Cup (COC) flashpoint rating of 145°C. Envirotemp FR3 Fluid has a COC flashpoint rating of 310°C.

Also, distribution transformers that are filled with ester fluid can operate at higher temperatures than mineral oil-filled distribution transformers, and still have the same life as the mineral oil-filled transformer. This increases the transformer kVA capacity. This added kVA capacity will prolong the life of the transformer's internal insulation system and improve summer heat storm performance.

As of April 2, 2018, all standard pole-type transformers supplied to SCE are now filled with ester fluid. Ester fluid-filled transformers are currently being installed to support new construction as well as transformer replacements driven by normal work processes (e.g., identified as deteriorated, overloaded, cutover to a higher voltage, etc.). These installations are not occurring on a proactive basis based on oil content alone. The full benefits and reduced risk of fire ignition by distribution transformers across the SCE system is expected to increase over time as the percentage of FR3-filled transformers rises across the system, including in HFRA areas.

1. Drivers Impacted

The use of FR3 transformers (C2) impacts sub-driver D2g (Equipment/Facility Failure – Transformer), as the new transformer fluid, with the higher flash point, will reduce the chance that a catastrophic failure will cause a fire ignition.

2. Outcomes & Consequences Impacted

Using FR3 transformers (C2) will not directly impact outcomes or consequences in the risk model.

D. Additional Controls Discussed in other chapters

In Chapter 12 (Climate Change), SCE models a control that likely also provides certain benefits to this Wildfire chapter. This is C2 – Fire Management Program. Table III-2 describes the interaction of Fire Management Program benefits between the two chapters.

Table III-2 – Control Included in Chapter 12 (Climate Change) with Providing Wildfire Benefit

Chapter 12 - Climate Change Chapter Control	Control Description	Likely Benefits for Wildfire Chapter
C2 – Fire Management Program	SCE maintains a Fire Management Team that includes fire management officers having experience as fire fighters and/or linemen. These fire management officers perform these activities: • Conduct training on electrical safety for first responders. • Proactively monitor fire threats to SCE infrastructure, coordinate with SCE Fire IMTs, and assist in restoration activities involving electrical assets. • Coordinate planning and response operations with external agencies and first responders. • Monitor climate change impacts on hazardous fuel (grass, heavy brush, chaparral, etc.) build-up that increase the severity and duration of wildfire events. Support project teams focus on hardening the grid to accommodate climate change drivers.	These efforts can reduce reliability impacts and increase the safety of our crews, first responders, and customers. For additional detail, please refer to Chapter 12 (Climate Change).

IV. Mitigations

Besides the controls detailed in Section III, SCE has identified potential new and innovative ways to mitigate this risk. These mitigations are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[40]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted
M1	Wildfire Covered Conductor Program	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1b	Underground Conversion	D1 - All, D2 - All, D3, D4	-	-
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	-	O1, O2	All
M3	PSPS Protocol and Support Functions	-	O1	All
M4	Infrared Inspection Program	D2f	-	-
M5	Expanded Vegetation Management	D1d	-	-
M6	Microgrids	-	All	R
M7	Enhanced Situational Awareness	-	All	All
M8	Fusing Mitigation	D2b, D2d, D2e, D2f	-	-
M9	Fire Resistant Poles (M1 Scope)	-	All	All
M9a	Fire Resistant Poles (M1a Scope)	-	All	All
M9b	Fire Resistant Poles (M1b Scope)	-	All	All

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

A. M1 and M1a[41] – Wildfire Covered Conductor Program

Installing covered conductor on SCE's system is an enhanced mitigation technique for reducing wildfire ignition risks, as compared to bare conductor. Prior to 2015, there were

[40] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).

[41] For RAMP modeling purposes, M1 captures the benefits of the covered conductor under WCCP, while M1a utilizes bare conductor for portions of circuits that meet SCD criteria and covered conductor for portions of circuits that meeting CFO criteria.

limited installations of older vintage covered conductor on SCE's system.[42] These limited installations typically occurred in heavily wooded areas with a history of outages (often related to animals and vegetation) and with limited access for tree pruning.

The covered conductor SCE is proposing to deploy as part of this mitigation utilizes a robust three-layer design. The design can prevent arcing caused by contact with a tree limb, conductor-to-conductor contact, or contact with a metallic balloon. In addition, the covering on the conductor (the "insulation") helps reduce the frequency of contact-related circuit interruptions that can lead to wire-down events. The insulation can also reduce the potential for electrocution in a wire-down event where the conductor remains energized. Finally, covered conductor will be sized to accommodate expected levels of fault current should faults occur, regardless of cause. This will also reduce the likelihood of wire-down events.

SCE's Wildfire Covered Conductor Program (WCCP) includes: (a) deploying covered conductor along with fire-resistant poles[43] when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.[44] The WCCP is related to, but distinct from, the current OCP. Both programs address some of the same root causes of wire-down events. But OCP addresses safety and reliability at a more general level, while WCCP specifically focuses on enhancing system safety and resiliency in light of wildfire risks.

While both programs will have some related benefits,[45] the programs necessarily differ in priorities and work practices. WCCP seeks to prevent faults that can cause ignitions in HFRA and prioritizes circuits with higher wildfire risk. OCP, on the other hand, aims to prevent wire-down events that create public safety hazards, and focuses on circuits with higher short circuit duty (SCD) values that serve more customers, typically in urban areas.

As part of our WCCP efforts, SCE developed a circuit prioritization methodology to guide the order in which circuits would be hardened with covered conductor.[46] This approach lets SCE

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[42] See A.18-09-002, Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program (Section IV.B.1) for additional details regarding SCE's Wildfire Covered Conductor Program, historical use of covered conductor, and current proposed covered conductor.

[43] WCCP includes deploying covered conductor, installing fire-resistant poles, and remediating tree attachments. For RAMP modeling purposes, fire-resistant poles were modeled as a standalone mitigation.

[44] Older construction in the forested areas of SCE's service area sometimes made use of existing trees to carry conductor rather than a separate utility pole. These are called "tree attachments."

[45] WCCP will have some safety and reliability benefits and OCP will have some wildfire benefits.

[46] Please refer to WP Ch. 10, pp. 10.43-10.46 (*Circuit Deployment Prioritization*)

maximize the risk reduction benefits over time and prioritize those circuits with greater wildfire risk; this includes ignition frequency, ignition consequence, and estimated mitigation effectiveness when covered conductor is installed.

SCE has approximately 4,500 distribution circuits in its service territory. About 1,300 of these circuits traverse HFRA. WCCP will focus on certain spans located in HFRA that pose the greatest risk of fire ignition on these approximately 1,300 circuits. SCE has identified approximately 4,000 circuit miles of bare overhead conductor in HFRA that appear to be best suited for reconductoring with covered conductor[47] to mitigate contact-related faults and alleviate the risk of wire-down events during fault conditions.

These circuit miles encompass three main fire ignition risk areas within HFRA: (1) spans with vintage small conductor at risk of damage during fault conditions; (2) spans with elevated risks of faults caused by contact from object (vegetation-related); and (3) spans with elevated risks of non-vegetation-related contact from object faults.

While M1 involves reconductoring *solely with covered conductor*, M1a is a hybrid mitigation. In M1a, portions of distribution circuits that meet SCD criteria (vintage small conductor as described in item 1 above) will be reconductored *with bare conductor.* Other portions of circuits that meet the CFO criteria (as described in items 2 and 3 above) will be reconductored *with covered conductor*.

Likewise, M1b – discussed in the section below – also involves a hybrid approach. But here, the combination is different. M1b consists of a combination *covered conductor and underground conversion*.

Table IV-2 summarizes the differences in technology used within each of the M1, M1a and M1b mitigations.

Table IV-2 – Mitigation Scope for M1 Options

Mitigation	Short Circuit Duty Scope (945 circuit miles)	Contact From Object Scope (1,481 circuit miles)
M1	Covered Conductor	Covered Conductor
M1a	Bare Conductor	Covered Conductor
M1b	Covered Conductor	Undergrounding

[47] SCE plans to complete deploying covered conductor for approximately 4,000 circuit miles by 2025.

Currently, SCE removes conductor and equipment attached to trees when these items are identified during vegetation clearing or in response to a trouble call. Conductor installed on a tree is vulnerable due to its close contact with the tree and the risk that the tree will die. A dead tree can fall, and is more susceptible to burning. SCE has approximately 1,640 tree attachments currently in service in HFRA as part of its primary overhead distribution system. For both (M1) and (M1a), SCE will replace tree attachments together with deploying covered conductor; the work may include installing new poles.

1. Drivers Impacted

The WCCP (both M1 and M1a) impacts the same drivers addressed by the OCP, namely: D1 – Contact from Object, and D2 – Equipment / Facility Failure.[48]

M1 is modeled with a higher impact on Driver D1 (Contact from Object) than M1a. With M1, we would install more covered conductor, which should reduce the frequency of contact-related faults.

2. Outcomes & Consequences Impacted

The WCCP will not directly impact outcomes or consequences in the risk model.

B. M1b – Underground Conversion

As shown in the Table IV-2 above, M1b modifies M1 by utilizing underground conversion instead of covered conductor for portions of circuits that meet the CFO criteria; portions of circuits that meet the SCD criteria would still be reconductored with covered conductor.

To date, SCE has not performed any overhead to underground conversions to mitigate wildfire risk. SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C.[49] In cities where undergrounding is required, SCE will install all-new construction that complies with the city's requirements. This would be a new mitigation activity for SCE, because currently there are no programs which specifically target converting overhead to underground lines to address wildfire risks.

An overhead to underground conversion involves removing all above-ground equipment, such as poles, conductor, transformers, switches, etc. We then replace the above-ground equipment by installing underground conduit, cable, vaults, manholes, transformers, switches,

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[48] Specifically, M1 and M1a affects the following sub-drivers: D1a (Contact from Object – Animal), D1b (Contact from Object – Balloons), D1d (Contact from Object – Vegetation), D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[49] See https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

etc. This mitigation would target circuits, or sections of circuits, where the risk of damage would outweigh the relatively high cost of conversion.

Undergrounding electric facilities can be technically challenging and may require multiple designs based on specific geographic factors. For example, portions of SCE's San Joaquin district are heavily-forested and sparsely populated. These areas have overhead circuits installed away from roadways, and traversing hills and other challenging terrain. This makes access by SCE personnel difficult and time-consuming. In some instances, this type of circuit construction uses trees to carry conductor. As we eliminate circuits with tree attachments, we will rebuild along the road to foster our ability to restore service in snowy conditions. When conditions prevent us from safely placing overhead lines (such as no road shoulder, or sloping or rocky terrain), we would underground in the road.

1. Drivers Impacted

This mitigation impacts all drivers and sub-drivers in the risk model. Since this mitigation would eliminate portions the overhead system, all drivers would be impacted by the undergrounding mitigation.

2. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

C. M2 – Remote-Controlled Automatic Reclosers (RARs) and Fast Curve Settings

M2 will perform two related efforts within HFRA: (1) installing 98 additional RARs with Fast Curve operating setting[50] in HFRA; and (2) updating the relay and/or settings on approximately 930 existing RARs and 1,164 circuit breakers with Fast Curve operating settings.

RARs are protective devices applied to mainline conductor that can automatically interrupt faults. The RARs will provide faster or more selective "fault clearing" to further reduce fire ignition risks and lessen service interruptions for SCE customers. These new RARs will provide fault interrupting capabilities with recloser blocking[51] and Fast Curve settings during Red Flag

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[50] Fast Curve Setting modifies the relay fault detection curve, providing faster fault detection and interruption. Once the updated settings are installed, the Fast Curve can be remotely activated or de-activated through SCE's monitoring and control radio network.

[51] Under normal circumstances, SCE automatically recloses its circuits after they are de-energized from a fault interruption. Automatic reclosing is used to allow electric service to be restored quickly following a fault which is momentary or temporary. During Red Flag Warning conditions, SCE's Distribution Control Center remotely blocks the automatic reclosing relay for CBs and RARs within its HFRA. For these circuits, the reclosing relay is disabled and, following a fault, the circuit remains de-energized until a

Warnings. Additionally, they will provide isolation points to help implement Public Safety Power Shutoffs (PSPS). In particular, SCE's PSPS protocols will benefit from additional RARs, because less customers will be impacted if SCE can de-energize a relatively smaller portion of a circuit.

Additionally, during Red Flag Warning conditions, Fast Curve settings will be remotely enabled by SCE's Distribution Control Center operators, resulting in typical faults being cleared more quickly. Fast Curve settings reduce fault energy by increasing the speed with which a relay reacts to most fault currents.[52] Compared to conventional settings, reduced fault durations anticipated with Fast Curve operating settings are expected to reduce heating, arcing, and sparking for many faults.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition outcomes (O1 and O2). Given the RAMP model structure, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling purposes, SCE represented this mitigation as impacting all consequences associated with O1 and O2.

Additionally, SCE notes that reducing wildfire risk by implementing more sensitive protective settings and the blocking of reclosing, will increase reliability consequences associated with faults that do not ignite wildfires. Since non-wildfire related faults are out of scope, the negative reliability impact of M2 is not reflected in the results of this risk analysis.

D. M3 – Public Safety Power Shutoff (PSPS) Protocol and Support Functions

SCE has recently instituted a formalized Public Safety Power Shutoff (PSPS) protocol where it may de-energize selected distribution circuits in HFRA[53] to reduce the chances of fire ignitions during the most extreme and potentially dangerous fire conditions. A PSPS event represents the

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patrol can inspect for sources of the fault. After the patrol inspection occurs, the circuit may then be re-energized and electric service restored.

[52] The Fast Curve reduction in fault energy is dependent on the fault magnitude and existing settings; as a general estimate, the configuration is expected to reduce fault energy by 50 percent.

[53] In rare circumstances, extreme fire conditions could dictate that SCE may need to de-energize a circuit outside the HFRA.

mitigation of last resort in a line of defenses against fire risk. This practice is aimed at keeping the public, SCE customers, and SCE workers safe. SCE currently considers many factors before de-energizing, including:

- Input from in-house meteorologists about current and forecast fire weather conditions;
- Wildfire fuel characteristics, and moisture levels of vegetation surrounding utility infrastructure; and
- Input from first responders and emergency management personnel regarding the potential impacts to ongoing evacuations, essential facilities/services, and at-risk customers.

In addition, SCE will deploy line patrol crews to assess circuit conditions before de-energizing. Prior to restoring service, we will also use these crews to confirm that it is safe to re-energize.

Public outreach is an important component of a utility's pre-emptive power shutoff protocol. SCE will complete outreach efforts with a number of stakeholders, including: state agencies, tribal governments, local agencies, and representatives from local communities. We will do so to help ensure these stakeholders are informed of the protocol and to solicit their feedback. This outreach will primarily be completed by October 2018, but will continue as needed to keep key stakeholders informed of the program. SCE continues to conduct community meetings and workshops to increase stakeholders' awareness and understanding of SCE's PSPS protocol, as well as to obtain feedback.

Additionally, SCE has procured a software solution to enhance its customer notification capabilities in order to more quickly and efficiently deliver notifications to customers before, during and following PSPS events. Specialized capabilities of this solution include:

- Ability to more quickly create and deliver customized outage communications in the customers' digital channel(s) of preference (Smartphone, SMS text, Email, and TTY);
- Bandwidth to deliver up to 1.5 million digital outage communications within one hour; and
- Ability to provide near real-time notifications and access historical records on notifications sent to customers.

To lessen the outage impacts to customers during PSPS events, on a case-by-case basis SCE will consider deploying available temporary mobile generators for Essential Use[54] customers to help maintain electric service for essential life, safety, and public services. Additionally, SCE plans to procure and deploy eight portable community power trailers to augment SCE's current customer outreach efforts during these events. Deploying the trailers will be prioritized based on factors like customer density and outage impact. These trailers can withstand high wind speeds associated with extreme fire conditions. The trailers can also provide local communities with charging stations for their phones, laptops, tablets, and other personal devices they rely upon to receive updates about the outage, monitor public safety broadcasts, and stay in contact with family and friends.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2).[55] For modeling, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling, SCE represented this mitigation as impacting all consequences associated with O1.

Additionally, SCE notes that reducing wildfire risk by implementing PSPS will increase reliability consequences associated with those circuit interruption events where a wildfire ignition is not avoided. Since non-wildfire related faults are out of scope, the negative reliability impact of M3 is not reflected in the results of this risk analysis.

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[54] Essential Use customers are defined by the Commission as those that provide essential public health, and safety services. *See* General Order 166. Examples include agencies providing essential fire or police services, hospitals and skilled nursing facilities, communications utilities, facilities supporting fuel and transportation services, and water and sewage treatment utilities.

[55] As previously mentioned, forecast fire weather conditions is a key component in the decision process of executing a PSPS event. Additionally, there may be rare instances where SCE will need to de-energize through PSPS without the presence of a Red Flag Warning event.

E. M4 – Infrared (IR) Inspection Program

1. Description

SCE is developing a biennial Infrared (IR) Inspection Program for overhead distribution lines within HFRA. Inspection findings will be prioritized per SCE's Distribution Inspection Maintenance Program (DIMP) manual and given appropriate system remediation timeframes. The IR program will identify "Hot Spots" on distribution system equipment. Examples of equipment that will be included in the inspection program are splices, connectors, switches, and transformers. Hot Spots are areas where there is a temperature difference between either two phases, or two pieces of metal on one phase. These Hot Spots are not visible to the naked eye, and can only be detected by a trained thermographer using an IR camera. Hot Spots are reliable predictors of future component failures that, if unaddressed, could potentially result in fires and customer outages.

IR inspections will help increase safety by enhancing critical circuit inspections and reducing fire safety hazards caused by potential equipment failures. These IR inspections will also improve reliability.

2. Drivers Impacted

The IR Inspection Program (M4) impacts Driver D2 (Equipment / Facility Failure)[56] by detecting in advance certain types of equipment failure before it occurs.

3. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

F. M5 – Expanded Vegetation Management

M5 expands SCE's vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated.

For example, a 75-foot tall palm tree located 50 feet from electrical facilities not only has the potential to fall into these facilities, but its palm fronds can dislodge and blow into electrical facilities, igniting a fire. While this palm tree meets all mandated compliance clearances and is not dead or dying, SCE may still identify it as a potential risk to be mitigated by either removing

[56] Specifically, M4 affects Sub-Driver D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

dead fronds or removing the tree altogether. SCE views this as an important effort in light of increasing winds that have the potential to blow palm fronds and other debris into utility lines from even greater distances.

1. Drivers Impacted

The Expanded Vegetation Management program impacts D1d (Contact From Object – Vegetation) by reducing the frequency of vegetation contact-related faults.

2. Outcomes & Consequences Impacted

The Expanded Vegetation Management program (M5) will not impact outcomes or consequences in the risk model.

G. M6 – Microgrids

A microgrid is a collection of generation sources (including conventional and renewable generators, demand side management, and energy storage) and loads capable of operating in parallel with, or independently of, the main power grid. In remote areas, especially those in rural or forested areas, electricity may need to pass over utility equipment located in HFRA. Microgrids could provide greater resiliency to critical customers, water pumping, and hospitals in these areas during times when grid power may need to be proactively shut off to minimize the potential for wildfire ignition during inclement weather conditions. Microgrids are not intended as a permanent service solution, but rather can serve as a backup power source to provide service continuity during critical periods.

1. Drivers Impacted

This mitigation provides resiliency during a PSPS event and will not mitigate any of the drivers. Therefore, Microgrids (M6) will not impact driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

This mitigation will impact the reliability consequences associated with all outcomes, because it provides for faster temporary restoration of power to customers during interruption events.

H. M7 – Enhanced Situational Awareness

M7 will enhance our wildfire situational awareness by deploying weather stations and High Definition (HD) cameras across our HFRA, a high-resolution weather model, and a high-performing computing platform for fire potential index modeling. Situational awareness is an integral part of emergency management, because SCE needs a granular understanding of what is happening across its service area prior to and during emergency events. SCE is further enhancing its situational awareness capabilities to address increasing fire risks throughout its service area. SCE is focused on accessing more detailed information about wildfire risk at the individual circuit level, to better understand how weather conditions might impact utility infrastructure and public safety in high fire risk areas.

SCE intends to enhance its existing weather models by installing additional weather stations on circuits within HFRA. These additional weather stations will enhance the resolution of existing weather models and provide real-time information to help make key operational decisions during potential fire conditions, including PSPS deployment.

When installed, weather stations use various sensors and communications to provide meteorologists with real-time weather data. This includes temperature, relative humidity, dew point, wind speed, wind direction, wind gust behavior, wind gust direction, and other variables.

The weather stations' capabilities include a datalogger, a central component of the station which measures signals coming from the weather station sensors.

Through October 2018, SCE has installed over 110 new stations. SCE's fire meteorologists will continue identifying potential locations for up to approximately 850 total weather stations by 2020.

SCE is installing pan-tilt-zoom (PTZ) HD cameras throughout its HFRA to enable fire agencies and SCE personnel to more quickly identify and evaluate emerging wildfires. Deploying HD cameras throughout our HFRA will enhance SCE's situational awareness capabilities and enable emergency management personnel, including fire agencies, to more swiftly respond to emerging wildfires. In particular, HD camera images save time in verifying and assessing a fire's severity as compared to sending fire crews to perform this assessment.

HD camera views will transmit into SCE's Situational Awareness Center, and will be used by our Incident Management Teams (IMT) to decide how to deploy crews and make other operational decisions, such as PSPS activation. These HD cameras will help mitigate potential safety risks to the public and prevent damage to electric infrastructure. Between 2018 and 2020, SCE is planning to install up to 160 PTZ HD cameras on approximately 80 towers. This will provide coverage of nearly 90 percent of SCE's HFRA.

SCE has contracted with IBM to access a high-resolution weather model. The model will forecast weather parameters such as temperature, wind speed and gusts, humidity, precipitation and fuel characteristics. It will provide these benefits:

- Enhanced resolution and more accurate forecast data to better inform deploying SCE's PSPS protocol;
- Severe-weather forecasting including wind, thunderstorms, heavy rain events and extreme temperatures;
- Visualization of weather conditions and forecasts around SCE infrastructure; and
- Overall support to SCE's IMT in developing HFRA forecasts and fire response plans.

SCE intends to deploy a high-performance computing platform to improve its ability to scientifically quantify the risk of wildfire ignitions in different geographic regions throughout its service area. SCE will procure advanced computer hardware and deploy state-of-the-art software that will run a sophisticated Fire Potential Index model. The model will account for various factors including weather, live fuel moisture, and dead fuel moisture to assess the level of risk of wildfire ignitions.

Our efforts here will also enable software to analyze decades of data for fuel and weather characteristics from past wildfire ignitions, and compare and contrast those variables against current conditions to forecast the Fire Potential Index. The output from this model will inform operational decisions, implement work restrictions, and optimize resource allocation for emergency situations.

SCE will implement an Asset Reliability and Risk Analytics program to build capabilities in predicting an asset's overall wildfire-related risk and prioritize work, repairs, and/or replacement(s) to minimize potential wildfire ignitions.

Additionally, the state's substantially increasing fire risk means that SCE must respond to more frequent and prolonged fire threats throughout its service area. SCE will augment its Business Resiliency staff with four full-time positions to accommodate the increased demands.

1. Drivers Impacted

This mitigation focuses on improving situational awareness and therefore will not directly impact any of the drivers in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve situational awareness related to wildfires in the SCE system, M7 will impact all consequences related to wildfire outcomes in the risk model.

I. M8 – Fusing Mitigation

M8 plans to install or replace fuses at approximately 15,613 fuse locations in two main groupings. The 15,613 figure represents the number of branch line locations in the HFRA. This mitigation should ensure that all locations are addressed. First, we will install new Current Limiting Fuses (CLFs) at 8,855 branch line locations. Second, we will replace existing fuses with CLFs at up to 6,758 existing fuse locations on circuits that traverse the HFRA. This program should reduce the risk of fire ignitions associated with SCE's distribution lines and equipment by reducing fault energy. We plan to complete this work during the 2018-2020 timeframe.

SCE has traditionally applied fuses on branch line locations to improve electric service reliability by limiting the number of customers affected by a fault. This practice has resulted in fuse application on approximately 43 percent of the HFRA-related branch circuits. This mitigation will result in fuse application of approximately 100% of HFRA-related branch circuits when complete. SCE has traditionally used conventional expulsion type fuses (conventional fuses) for fuse applications. For this M8, SCE intends to utilize CLFs instead of conventional fuses for most applications in the HFRA. We selected CLFs for this application because they provide faster fault clearing for most faults and reduce fault energy, compared to a conventional fuse.

Table IV-3 illustrates the groups of fuse installations and replacements.

Table IV-3 – Fuse Groups

Group	Sub-group	Fuse Locations
Installing new CLFs	N/A	8,885
Replacing existing fuses	Conventional expulsion type	1,656
	Conventional non-expulsion type	5,102
Total		**15,613**

For the first group (installing new CLFs), M8 will install new fuses on distribution circuit branch lines in HFRA which are not presently fused, or that may benefit from further segmentation via additional fuse installations. The program will also replace certain existing conventional fuses with CLFs to further minimize ignition risk.

The second group (replacing existing conventional fuses) can be divided into two sub-groups. The first sub-group involves replacing existing expulsion type fuses which require brush clearing at the base of the pole to remove potentially flammable vegetation.[57] The second sub-

[57] This aligns with the CalFire Power Line Fire Prevention Field Guide.

group involves replacing existing conventional non-expulsion type fuses that would benefit from the current limiting technology for energy reduction, but would otherwise be exempt from brush clearing per CalFire's Power Line Fire Prevention Field Guide.

1. Drivers Impacted

SCE's Fusing Mitigation Program impacts Driver D2 - Equipment/Facility Failure.[58] It does so by de-energizing branch lines that experience faults and reducing the fault energy that can damage conductors, insulators, or connectors.

2. Outcomes & Consequences Impacted

The Fusing Mitigation (M8) will not directly impact outcomes or consequences in the risk model.

J. M9, M9a, M9b[59] – Fire-Resistant Poles

At locations where SCE is installing covered conductor in HFRA and pole replacements are required, SCE will use fire-resistant composite poles, where appropriate, instead of traditional wood poles. The variation in mitigation scenarios for M9 (M9, M9a, and M9b) reflect different volumes of installing fire-resistant poles. The volumes of these installations are commensurate with the volumes of covered conductor deployment in M1, M1a, and M1b, respectively. Table IV-4 illustrates this relationship and the number of pole installations contemplated for this mitigation.

Table IV-4 – Covered Conductor & Fire-Resistant Pole Deployment Scenarios

Wildfire Conductor Mitigation Variant	Conductor Type and Volume (circuit miles)	# of Fire-Resistant Poles Modeled in M9 Variant
M1 *(All Covered)*	Covered Conductor - 2,426	27,513
M1a *(Bare + Covered)*	Covered Conductor - 1,481 Bare Conductor - 945	23,940
M1b *(Covered + Underground)*	Covered Conductor – 945	11,060

[58] Specifically, M8 impacts the following sub-drivers: D2b (Equipment/Facility Failure – Conductor), D2d (Equipment/Facility Failure – Fuse), D2e (Equipment/Facility Failure – Insulator), and D2f (Equipment/Facility Failure – Splice/Connector/Clamp).

[59] For RAMP modeling purposes, M9a corresponds to the number of poles requiring replacement that are associated with M1a bare conductor alternative, while M9b corresponds to the number of poles requiring replacement with the M1b undergrounding alternative.

These poles are specifically designed to withstand wildfires; use of the poles will harden the distribution system. This increases the chances that SCE equipment, including conductor, will remain in the air should a wildfire occur, which will afford multiple benefits. First, the equipment is less likely to be damaged if it is out of the path of the fire. Second, with less damage, SCE can re-energize more quickly after a wildfire event. Finally, if the utility equipment remains intact, then members of the public and first responders are safer.

SCE has experience with similar composite poles. Compared to steel poles, composite poles are non-conductive and resistant to corrosion. And compared to wood poles, composite poles are less susceptible to wildlife damage (e.g., woodpeckers), rotting, and fires, and are also lighter in weight and can carry more load (when compared to wood poles of the same class and size). In general, composite poles are preferred to wood poles in several contexts, such as restricted vehicle access (for sectional composite poles) and areas of accelerated pole degradation.

The composite poles SCE plans to install are manufactured using polyurethane resin and E-glass fiber to create a fiber-reinforced polymer (FRP) laminate. Manufacturer testing has proven that the laminate is self-extinguishing (i.e., fire-resistant). In addition, a shield manufactured from the same fire-resistant material is wrapped around the composite pole sections at the manufacturing plant. When the pole is installed, the shield is embedded 12 inches below the ground line of the final grade. Manufacturer testing has shown[60] that the shield will increase fire resistance, enabling the pole to withstand an "extreme" wildfire.[61]

1. Drivers Impacted

This mitigation is focused on provide resiliency during a wildfire event and therefore will not reduce any driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve grid resiliency related to wildfires in the SCE system, M9 will impact all outcomes and consequences in the risk model.

[60] RS Technical Bulletin: 17-010, *RS Poles and Fire Shields Fire Performance*, at p. 1 (February 1, 2018), *available at* https://www.rspoles.com/sites/default/files/resources/C801---17-010---RS-Poles-and-Shields-Fire-Performance-01-Feb-18.pdf.

[61] *Id.* at p. 13. "Extreme" wildfire exposure is defined as gas temperatures between 800 to 1,200°C and exposure of 121 to 180 seconds. *Id.* at p. 4.

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Sections III and IV and has developed a Proposed Plan of controls and mitigations to pursue, as shown in Table V-1 below. Before discussing these controls and mitigations in detail, certain aspects of the analysis should be placed in context. Examining the relative RSE values shows that, in certain cases, the RSE does not accurately capture certain “real life” factors that are critical in actually choosing mitigations.

First, as SCE discussed in Chapter 1 (RAMP Overview), restricting the evaluation of risk reduction and risk spend efficiency to the 2018-2023 RAMP period can distort the benefits of those mitigations whose benefits will extend significantly beyond 2023. Long-lived assets that are installed during the RAMP period continue to operate and provide risk reduction benefits for many years thereafter. There can be dissonance in RSE comparisons between this type of mitigation compared to an O&M mitigation that has more short-lived benefits. In these cases, the long-lived mitigation will have an RSE that is understated compared to the short-term O&M mitigation.

This dissonance can be seen, for example, when assessing mitigation M1 (Wildfire Covered Conductor Program). The long-term benefits are simply not fully captured in the RSE calculation. To illustrate this, SCE has prepared a long-term pilot analysis. The analysis is found at Appendix 1 to this chapter. In that Appendix, the RAMP analysis is extended out to 50 years rather than the 6-year RAMP period, to estimate the full benefit that the covered conductor assets provide over their useful life. When this longer-term pilot analysis is performed, we see the following results:

- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a mean basis increases 18 times.
- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a tail average basis increases 18 times.[62]

Thus, the RSE comparison is somewhat “skewed” between the longer-lived Wildfire Covered Conductor Program (M1) and the O&M mitigation activities such as PSPS Protocol and Support Functions (M3) and Infrared Inspection Program (M4). The risk reduction benefits of M1 are understated compared to the risk reduction benefits of M3 and M4.

[62] The mean and tail average results have not had any discounting applied.

Also, the RSE necessarily cannot take into account certain operational realities. If one looks solely at the RSE scores, there might be a question as to why SCE doesn't forego the Covered Conductor Plan to a significant degree in favor of the PSPS Protocol and the Infrared Inspection Program. But the respective programs address different aspects of mitigating wildfire risk. In today's increasing wildfire risk environment, a sound wildfire mitigation plan must address conductors. The PSPS Protocol and Infrared Inspection Program do not directly address conductors and conductor performance. Making mitigation decisions in this case purely on RSE would lead to significant parts of the system and potentially significant risk issues being unaddressed.

Moreover, there are also real-life "scalability" issues that the RSE comparison cannot take into account. There are practical limits in how much PSPS and infrared inspections can be deployed. One is a system shut-off protocol; it is a mitigation of last resort. The other is an inspection program that does not, and cannot, actually strengthen system components against wildfires.

Table V-1 – Proposed Plan (2018 – 2013 Totals)[63]

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.39	0.0038
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	2.27	0.0020*	7.22	0.0062*
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0310	3.29	0.1057
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.90	0.0889	6.55	0.3068
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1017	0.93	0.3243
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.20	0.0033
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.84	0.0148	3.14	0.0552
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.73	0.0079
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$ 137	$ -	0.60	0.0043	2.21	0.0161
			Total	**$1,609**	**$447**	**7.65**	**0.0037**	**25.83**	**0.0126**

*Full benefits are not included in 6-yr RSE for M1. If full benefits (without any discount) were included for M1 and it was modeled independently, its RSE would increase by 18 times on both a mean and tail-average basis. Please see Section IX-Appendix 1 to this Chapter, and discussion above, for additional details.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

[63] With respect to M1 (Wildfire Conductor Program): Since Tree Attachments were not modeled, the costs associated with Tree Attachments are not included with the M1 – Wildfire Covered Conductor Program costs. Additional information on the modeling of Tree Attachments is found in Section VIII – Lessons Learned.

There are a few additional items to note when examining the Proposed Plan and the relative mitigation scores:

- *Wildfire Covered Conductor Program [M1]* – the risk benefits are understated to an additional degree because the *benefits* of this mitigation associated with Chapter 5 - (Contact with Energized Equipment) are *not* included in this chapter, but the *full cost* of this mitigation *is* included. The costs are not apportioned out between Wildfire and Contact with Energized Equipment. Each chapter calculates RSE using the full cost of the program.
- *PSPS Protocol and Support Functions [M3]* – the risk benefits are overstated because we do not capture the reliability consequences that occur when de-energizations do not prevent a fire.
- *Enhanced Situational Awareness [M7]* – the risk benefits are understated because they do not capture the positive effects of addressing and mitigating fires that are not associated with SCE.
- *Fire-Resistant Poles [M9]* – the risk benefits are understated because they do not capture the positive effects of addressing fires not associated with SCE.
- *RAMP and GS&RP* – For illustrative purposes, SCE has included a workpaper[64] demonstrating that SCE's GS&RP application and RAMP are aligned. The workpaper shows that comparable GS&RP and RAMP analyses produce similar results concerning the cost efficiency of bare conductor compared to covered conductor. Please also see the discussion found in section V.D below.

A. Overview

As we developed our Proposed Plan, we considered many factors, including:

- The risk assessment outlined in this chapter;
- How various controls and mitigations impact the drivers, triggering event, outcomes, and/or consequences;
- The potential execution speed and timing of mitigations;
- How various mitigations might complement one another or existing controls; and
- Cost.

[64] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).

In light of the “new normal” regarding the increasing wildfire risk in SCE’s service area, the Proposed Plan represents a comprehensive approach to enhance SCE’s existing wildfire mitigation efforts and target the principal drivers that lead to potential wildfire ignitions.

A primary component of SCE’s Proposed Plan includes deploying covered conductor (M1). This mitigation targets Driver D1 (Contact from Object). That driver represents the majority of faults that can potentially lead to wildfire ignitions.

As described in Section IV.A (M1 - Wildfire Covered Conductor Program), this mitigation seeks to prevent faults from occurring, and targets three categories of overhead lines: (1) spans with vintage small conductor at greater risk of being damaged during fault conditions; (2) spans with elevated risks of faults due to vegetation-related contact from objects; and (3) spans with elevated risks faults due to non-vegetation-related contact from objects.

The first category, vintage small conductor, is addressed by both SCE’s existing Overhead Conductor Program, and SCE’s Wildfire Covered Conductor Program. The scope represented by C1 (Overhead Conductor Program Covered 2021-2023) consists of in-flight Overhead Conductor Program projects that will be executed with the bare wire standards in place prior to developing our Wildfire Covered Conductor Program. If we have conductor that meets the criteria for this category but is not included in C1, the mitigation will occur through M1 (Wildfire Covered Conductor Program).

The second category, vegetation-related faults, is addressed by SCE’s Wildfire Covered Conductor Program (M1), Expanded Vegetation Management (M5) and Vegetation Management (CM1). Mitigation M5 is incremental to SCE’s existing vegetation management practices (CM1), and will further mitigate tree-related ignitions, particularly in areas where covered conductor is not being deployed.

The third category, non-vegetation-related faults, is addressed primarily by our Wildfire Covered Conductor Program (M1). While the primary selection and targeting of the Wildfire Covered Conductor Program focused on mitigating wildfire outcomes and consequences, M1 is expected to provide meaningful improvements in reliability due to its inherent ability to prevent contact from object-related faults (D1).

Remote-Controlled Automatic Reclosers and Fast Curve Settings (M2) and Fusing Mitigation (M8) work with each other, and work in conjunction with our Wildfire Covered Conductor Program (M1), by reducing the energy associated with faults that may occur, regardless of the cause of the fault. These mitigations complement the Wildfire Covered Conductor Program by providing this energy-reducing protective capability for both covered and bare conductor, either during the time period before covered conductor is scheduled to be installed, or for lines that are not targeted for covered conductor deployment. These mitigations provide ignition-related benefits for all types of faults, including those faults that cannot be mitigated by covered conductor.

Infrared inspections (M4) complement the above-mentioned mitigation measures by targeting additional sub-drivers to D2 (Equipment/Facility Failure drivers) that are not mitigated by covered conductor, such as D2a (Capacitor Banks) and D2g (Transformers).

Covered conductor (M1) and infrared inspections (M4) are expected to mitigate Sub-Driver D2f (Splice/Clamp/Connector). Infrared inspections are expected to mitigate these types of failures on lines when the installation of covered conductor is scheduled but has not yet occurred, or when there are lines that are not targeted to have covered conductor.

Using ester fluid FR3 transformers (C2) for both new and future replacements of overhead transformers works in conjunction with infrared inspections, by reducing both the frequency of transformer failures (slower aging of insulation) as well as reducing the potential consequence should a transformer fail (it is less likely that fluid has reached its flash point).

PSPS Protocol and Support Functions (M3) represents SCE's mitigation of last resort and would be exercised if extreme fire conditions develop and existing controls and other proposed mitigations are insufficient to address the emergent risk. Enhanced Situational Awareness (M7) (i.e., high-resolution forecasting coupled with weather stations) is expected to improve SCE's predicting capabilities. It should reduce false positives that result in pre-emptively deploying resources and notifying customers in advance of potential de-energization. We also expect improvement in targeting of PSPS; this should reduce the number of circuits that have to be de-energized. While SCE believes PSPS should be available in extreme circumstances, it is not a long-term solution that can be used in place of the other mitigations shown in the portfolio.

Lastly, Enhanced Situational Awareness (M7) and Fire-Resistant poles (M9) aim to mitigate consequences associated with ignitions that do occur. These mitigations can help reduce the size of wildfires through faster suppression response and faster restoration times should fires engulf SCE infrastructure.

B. Execution feasibility

While some of the mitigations listed in the Proposed Plan have not been previously executed by SCE to the proposed scale, SCE has obtained experience in execution and a greater understanding of cycle times by deploying in advance some portion of the mitigation portfolio. This includes starting to install covered conductor on the highest-priority circuits, and deploying some weather stations and HD cameras in HFRA. The current mitigation deployment timeline evaluates mitigation deployment cycle time, risk reduction, and resources constraints to develop a plan to maximize risk reduction in light of these factors.

While the Proposed Plan represents significant work over the intended time period, it is operationally feasible to increase mitigation deployment capacities and complete this target in addition to its other ongoing and planned activities. In early 2018, SCE created a program management office (PMO) focused exclusively on bolstering public safety and grid resiliency. We created the PMO in part to consolidate SCE's grid-hardening projects to enable more streamlined and expeditious deployment. As part of this effort, SCE carefully considered how quickly it could move forward with its wildfire mitigation portfolio. SCE views the proposed timeline as both operationally feasible and prudent, given the importance and urgency of mitigating wildfire risks and hardening the grid.

C. Affordability

The Proposed Plan has the second-lowest cost of the three plans. The RSE of the Proposed Plan is just slightly lower than the RSE of the Alternative Plan #1, and significantly higher than the RSE of Alternative Plan #2. The Proposed Plan's RSE is less than Alternative #1 because the conductor-related mitigations in Alternative #1 cost less than the conductor-related mitigations in the Proposed Plan, and the RSE of each conductor-related mitigation is lower than the respective portfolio-level RSE.[65]

Using covered conductor is a crucial part of SCE's Proposed Plan. Each of the three plans includes a significant amount of conductor-related controls and mitigations. To understand the differences in underlying cost-effectiveness of the Proposed Plan compared to the alternative plans, it is helpful to examine the RSEs of the conductor-related controls and mitigations.

The conductor-related controls and mitigations are as follows:

- The Proposed Plan uses C1 and M1.
- Alternative Plan #1 uses C1a and M1a.
- Alternative Plan #2 uses C1 and M1b.

The Proposed Plan's conductor related controls and mitigations provide the most value of all conductor-related controls and mitigations in the three plans. The conductor-related

[65] Please see Section V.A for a discussion of underrepresentation of long-term benefits for covered conductor.

controls and mitigations in the Proposed Plan have a higher RSE than Alternative Plan #1 and Alternative Plan #2.

The Proposed Plan's conductor-related controls and mitigations have a much higher Mitigation Risk Reduction than those Alternative #1. While Alternative Plan #2 has the largest Mitigation Risk Reduction among the three plans for conductor-related controls and mitigations, it also has a much lower RSE than the Proposed Plan and Alternative Plan #1.

Table V-2 below shows a comparison of conductor options and associated risk reduction and risk spend efficiency.

Table V-2 – Comparison of Conductor-Related Mitigation Options

Figures represent 2018 – 2023 totals	Cost ($M)	Mitigation Risk Reduction (Mean)	Risk Spend Efficiency (Mean)	Miles Addressed[66]
C1 and M1 *(Proposed Plan)*	$1,263	2.39	1.892E-03	2,680 circuit miles: ***M1:*** *2,426 Covered* ***C1:*** *65 Covered + 189 Bare* *0 underground*
C1a and M1a *(Alternative Plan #1)*	$1,044	1.90	1.820E-03	2,680 circuit miles: ***M1a:*** *1,481 Covered + 945 Bare* ***C1a:*** *254 Bare* *0 underground*
C1 and M1b *(Alternative Plan #2)*	$5,501	2.99	0.365E-03	2,680 circuit miles ***M1b:*** *945 Covered+ 1,481 Underground* ***C1:*** *65 Covered + 189 Bare*

The Proposed Plan assumes deployment of our Overhead Conductor Program with bare conductor in years 2018-2020 and covered conductor in years 2021-2023 (C1), and the Wildfire Covered Conductor Program with covered conductor in years 2018-2023 (M1).

[66] SCE modeled three different conductor types (covered, bare, and underground) across the three portfolios. Different conductor types were selected in each portfolio based on the fault risk areas within HFRA. For example, Alternative Plan #1 evaluates bare conductor use in short circuit duty areas. Alternative Plan #2 evaluates use of Underground Cable for CFO areas.

This fundamentally differs from Alternative Plan #1, which assumes the existing Overhead Conductor Program with entirely bare conductor in years 2018-2023 and the Wildfire Covered Conductor Program with a mix of bare conductor and covered conductor in years 2018-2023.

This is also fundamentally different than Alternative Plan #2, which assumes existing Overhead Conductor Program bare conductor in years 2018-2020 and covered conductor in years 2021-2023, and the Wildfire Covered Conductor Program with a mix of covered conductor and underground conversion in years 2018-2023.

Therefore, the alternative plans reflect two theoretical "modifications" to the Proposed Plan. Alternative Plan #1 represents a "downgrade" of the Proposed Plan, with increased use of bare conductor. Alternative Plan #2 represents an "expansion" of the Proposed Plan, with increased use of underground conversion.

There are similarities in the RSEs of the Proposed Plan and Alternative Plan #1. The modeled scope in the Proposed Plan and Alternative Plan #1 are over 60% identical (each plan includes at least 189 miles of bare conductor and 1,481 miles of covered conductor). Moreover, the variation in scope is less than 40% between the two Plans. The greater RSE of conductor-based mitigations within the Proposed Plan relative to the Alternative Plan #1 would have been more pronounced had the two plans been modeled with a much larger variation in scope. We chose to model with similar scope to evaluate risk scoring while minimizing variability. This is illustrated by *the large variation* in RSE between the Proposed Plan and Alternative Plan #2, which has a significantly different scope (nearly 1,500 miles of underground conversion) and a much clearer difference in RSE (significantly lower RSE).

D. Other Considerations

The mitigation effectiveness discussions in this RAMP chapter differ in several ways from the mitigation effectiveness discussions found in SCE's GS&RP application. The basic mitigation effectiveness **inputs** used within GS&RP and RAMP are closely aligned. But those inputs are **analyzed** using different methodologies. For example, the GS&RP application compares implementations of different conductor mitigations (i.e., bare versus covered versus underground conversion) across the entire HFRA to develop a mitigation effectiveness factor.[67] The application then develops a mitigation-to-cost ratio for each conductor mitigation. It does not combine the different conductor mitigations.

[67] See page 52 of the GS&RP filing (A. 18-09-002).

In contrast, the RAMP analysis compares different combinations of conductor mitigations (e.g., M1, M1a, or M1b, paired with other mitigations) implemented across a portion of the HFRA. Our RAMP analysis then uses the MARS methodology to calculate a Mitigation Risk Reduction for each portfolio, and then calculates a Risk Spend Efficiency for each portfolio based on cost.[68]

Despite the differences in analytical approaches, the GS&RP and RAMP are aligned. For illustrative purposes, we have included a workpaper that provides an example of applying the GS&RP analysis parameters to RAMP modeling.[69] The workpaper takes the GS&RP analysis of bare conductor versus covered conductor, and runs an equivalent analysis using the RAMP model.[70] As shown in the workpaper, the comparable GS&RP and RAMP analyses produce similar results regarding the cost efficiency of bare conductor compared to covered conductor.

The Proposed Plan is informed by SCE's current capabilities for evaluating and prioritizing mitigation measures, SCE's capabilities to predict potential driver occurrences, and the availability of technologies that can be deployed and are effective at mitigating wildfire risk. In performing these mitigation measures over time, different factors may drive adjustments to the Proposed Plan. These factors include changes to the risk landscape that may be impacted by climate changes and/or mitigation measures implemented by third parties, and improvements in SCE's ability to evaluate wildfire risk across its service territory. Also, policy constraints may restrict SCE's ability to implement desired mitigations or may change how we allocate limited resources.

Lastly, as new technologies emerge, SCE will continue to evaluate the effectiveness of more advanced solutions and how they may complement its existing portfolio of mitigation measures. If new measures prove to be better than existing ones, SCE will work to transition to these improved measures as appropriate.

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[68] See Chapter 2 (Risk Model Overview) for additional detail regarding MARS, MRR and RSE.

[69] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).

[70] In running the equivalent analysis, SCE used the same potential frequency of ignition and scope assumptions under which the GS&RP analysis was performed.

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an alternative plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2013 Totals)[71]

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Overhead Conductor Program - (Bare Only)	2018	2023	$ 98	$ -	0.08	0.0008	0.24	0.0025
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	2018	2023	$ 947	$ -	1.83	0.0019	5.87	0.0062
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0311	3.34	0.1073
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0893	6.64	0.3112
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.30	0.1031	0.95	0.3324
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0010	1.24	0.0034
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.19	0.0562
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9a	Fire Resistant Poles (M1a Scope)	2018	2023	$ 119	$ -	0.53	0.0044	1.99	0.0167
			Total	**$1,372**	**$447**	**7.12**	**0.0039**	**24.40**	**0.0134**

A. Overview

Alternative Plan #1 deploys many of the same controls and mitigations as the Proposed Plan. However, a key difference between these two plans is the conductor-related mitigations chosen. Alternative Plan #1 represents a scenario where SCE uses the less expensive, and less effective, bare reconductoring mitigation in place of covered conductor. Alternative Plan #1 (using C1a) deploys bare conductor to target vintage small conductor for work between 2021-2023. In contrast, the Proposed Plan (using C1) deploys covered conductor for that same period.

Alternative Plan #1 also includes M1a, which uses bare conductor for the portions of circuits designated as short circuit duty. In contrast, the Proposed Plan includes M1, which uses covered conductor for those same portions. As discussed in Section V (Proposed Plan) bare reconductoring is less effective than using covered conductor at addressing the wildfire risk.[72] This was a key factor in our decision not to select Alternative Plan #1.

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[71] With respect to M1a: Since Tree Attachments are not modeled, the costs associated with Tree Attachments are not included with the M1a – Wildfire Covered Conductor Program (CFO – CC, SCE Lengths – Bare) costs.
[72] Please see Section V.C for additional detail.

Lastly, with respect to fire-resistant Poles, Alternative Plan #1 includes M9a as it corresponds to a reduced number of pole replacements associated with bare conductor. Bare conductor imparts lower gravity and wind loads on the poles as compared to covered conductor. In contrast, the Proposed Plan includes M9, to align with the type and volume of conductor deployed in that plan.

The remaining control (C2) and mitigations (M2 through M5, M7, and M8) remain identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use bare conductor for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of Alternative Plan #1 is very similar to the Proposed Plan.

C. Affordability

Alternative Plan #1 represents the least expensive plan, but also provides the least amount of risk reduction. Bare reconductoring is much less effective than covered conductor in terms of avoiding wildfires. Additionally, the fact that bare reconductoring is unable to mitigate the majority of fault types that are associated with fire ignitions makes Alternative Plan #1 less desirable.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan.

VII. Alternative Plan #2

SCE developed one other alternative plan, as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 (2018 – 2013 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.38	0.0037
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1b	Underground Conversion	2018	2023	$ 5,399	$ -	2.87	0.0005	9.00	0.0017
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0312	3.26	0.1048
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0896	6.49	0.3040
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1009	0.91	0.3179
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.19	0.0032
M6	Microgrids	2021	2023	$ 10	$ -	0.00	0.0000	0.00	0.0000
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.13	0.0551
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.71	0.0078
M9b	Fire Resistant Poles (M1b Scope)	2018	2023	$ 55	$ -	0.23	0.0042	0.85	0.0155
			Total	$5,775	$447	7.90	0.0013	26.09	0.0042

A. Overview

In Alternative Plan #2, SCE chooses to rely on underground conversion (M1b) and only selects covered conductor for a portion of the targeted circuits (M1b uses underground conversion for the portions of circuits targeted as CFO). In contrast, the Proposed Plan uses covered conductor (M1) for those same portions. Underground conversion is more effective than covered conductor in addressing fire risk, but is substantially more expensive.

Finally, in scoping the use of fire-resistant poles, Alternative Plan #2 selects M9b, while the Proposed Plan uses M9. M9b involves only replacing poles associated with the portions of circuits designated as short circuit duty. Since Alternative Plan #2 includes underground conversion, the scope of M9b will include fewer fire-resistant poles, since none are required for underground portions of the system. Besides the underground conversion, Alternative Plan #2 also include microgrids (M6). Microgrids provide limited incremental reliability benefits to mitigate outage impacts related to PSPS.

Like Alternative Plan #1, the remaining control (C2) and mitigations (M2 through M5, M7, and M8) for Alternative Plan #2 are identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use underground conversion for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of this alternative is significantly impacted by using underground conversions (M1b). As described in Section IV.B, undergrounding overhead lines is considerably more complex than overhead construction, even with covered conductor. This complexity increases the construction time and costs, which impacts available resources.

The complexity also adds to the time needed to mitigate the same quantity of circuit miles. This meaningfully decreases the feasibility of executing Alternative #2. These execution challenges influenced SCE in determining that this alternative was not the most prudent one.

C. Affordability

Alternative Plan #2 gives an increase in risk benefits at substantially increased costs compared to the Proposed Plan. Notably, Alternative Plan #2 reflects the fact that this portfolio (including substantial undergrounding) provides approximately 3% incremental risk benefit on a mean basis compared to the Proposed Plan. But Alternative Plan #2 is approximately *three times as expensive* as the Proposed Plan. This principally drives the lesser RSE of Alternative Plan #2 compared to the Proposed Plan. As such, it appears that Alternative Plan #2 does not provide the most value in addressing wildfire risk.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan. However, when compared to overhead lines, underground lines have several drawbacks that were not captured in the modeling and analysis. Underground systems:

- are more difficult to repair;
- cannot be visually inspected;
- require service interruptions to repair; and
- are more difficult to troubleshoot in emergencies, which can lead to longer outages.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Through the RAMP process, SCE has learned some important lessons in degrees of confidence in modeling mitigation effectiveness, constraints and limitations of the bowtie structure, and mitigations that cannot be easily modeled. Each area is discussed below.

1. Constraints of Bowtie-Structured Analysis

Use of the bowtie structure can limit our ability to assess the complete suite of risk benefits and tradeoffs associated with mitigations assessed in this chapter.

For example, the triggering event – i.e., the center of the bowtie – for wildfire analysis is an ignition associated with SCE in the high fire risk area. However, SCE's wildfire mitigation strategy focuses not only on fire prevention (i.e., reducing potential ignitions) but also suppression (i.e., more rapid identification and assessment of wildfires) and enhancing system resiliency (i.e., more robust design that can withstand damage during wildfires).

Because the triggering event in this analysis was limited to fires associated with SCE facilities, the fire prevention benefits of SCE's controls and mitigations are represented. However, the full suppression benefits and system resiliency benefits of SCE's controls and mitigations are understated, because these are benefits apply to *all fires*, not just SCE-associated fires.

Some operational measures such as PSPS [M5] have operational risks that are likewise understated due to the bowtie structure. The triggering event in the bowtie limits the analysis to fire ignition events. Implementing PSPS results in de-energizing selected circuits under Red Flag conditions, but it is virtually guaranteed that there will be more de-energized circuits then there will be ignitions avoided. The reliability "risk penalty" for de-energization (CMI for customers on these circuits) will accrue for all PSPS implementation events, but the risk analysis only evaluates the smaller number of ignition events. Therefore, the center of the bowtie itself prevents a complete analysis of all of the adverse operational risks associated with PSPS implementation.

2. Mitigation Benefits Not Captured in the Risk Analysis

SCE modeled the risk benefits of mitigations relative to the risk being evaluated in the chapter. Sometimes, a mitigation (such as M9 – Fire-Resistant Poles) can provide benefits in reducing the risk associated with ignitions associated with SCE. A mitigation like fire-resistant poles can also provide benefits in connection with fires that are not associated with SCE. In other words, the scope of this chapter necessarily focuses on fire ignitions that are associated with SCE. But a fire-resistant pole is "indifferent" to the cause of the fire. Its resistant capabilities will apply regardless of who or what caused the fire.

Additionally, the benefits of fire-resistant poles (and several other controls and mitigations in this chapter, and others) will continue beyond the six-year RAMP window.[73] Accordingly, the total benefits of these poles, as modeled in this chapter, are understated, since our analysis focuses on risk benefits over the 2018-2023 period.

B. Data Collection & Availability

To develop consequence distributions for modeling purposes, SCE utilized data reported by CalFire for statewide fires greater than 300 acres, with a cause classified by CalFire as "Electric Power." The data was collected in October 2018, and 2017 fire data was not yet available within the Redbooks that CalFire publishes. Given the significance of the 2017 fire activity, SCE reviewed news releases issued by CalFire to collect data on several additional fires from 2017 that had a cause classified by CalFire as being "caused by trees coming into contact with power lines" or being "caused by electric power and distribution lines, conductors and the failure of power poles."[74]

SCE also faced challenging data collection and availability issues regarding consequence models for fires. For example, the CalFire data was not immediately helpful for developing serious injury, fatality, and financial consequence models for smaller fires. Generally, the CalFire data provided far less information on the financial and safety consequences of smaller fires.

SCE faced a different data challenge in modeling the reliability consequences for both small and large fires. In general, SCE has a large and robust data source for outage information (ODRM). Unfortunately, while this database captures CMI outage characteristics for fire-related outages in the SCE system, it does not include details of the corresponding fire characteristics

[73] Please see the Appendix in Section IX for additional detail

[74] 2017 fires that were identified in 2018 CalFire press releases that were included within analysis include: La Porte, Lobo, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket, Atlas, Cascade, and Liberty fires. These links provide the specific detail:
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause%20v2%20AB%20(002).pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause.pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/Cascade%20Fire%20Cause%20Release.pdf
http://www.rvcfire.org/Documents/NEWS%20RELEASE%20-%20CAL%20FIRE%20INVESTIGATORS%20RELEASE%20CAUSE%20OF%202017%20LIBERTY%20FIRE.pdf

(i.e., larger or smaller, Red Flag or non-Red Flag Days, SCE- or non-SCE-associated ignition). Because ODRM is a circuit-level outage database and not a fire-related outage database, some assumptions were required to translate circuit-level outage details into fire-level outage consequence distributions for reliability.[75] As a future opportunity for improvement, directly tracking CMI consequences of fires in fire databases would be preferable to attempting to merge separate fire and outage databases.

C. Performance Metrics

The following metrics can help track performance related to wildfire risk:

1. Fire Ignitions Associated with SCE Equipment

This metric relates to ignitions occurring in SCE's service area. Specifically, SCE tracks Commission-reportable ignitions related to SCE electrical equipment or workers, that meet all of the following criteria: (1) A self-propagating fire of material other than electrical and/or communication facilities; (2) The resulting fire traveled greater than one linear meter from the ignition point; and (3) SCE has knowledge that the fire occurred at the time of filing the report. This metric represents the triggering events associated with the wildfire risk bowtie.

2. Covered Conductor Installed in HFRA

This metric tracks the number of circuit miles of covered conductor installed in SCE's HFRA. This metric is directly associated with M1, which aims to reduce the drivers that lead to ignitions. The quantity of covered conductor installed represents the extent to which SCE's overhead distribution lines in HFRA are hardened and represents a leading indicator for fire ignitions. SCE's target for this metric, at this time, is 2,426 circuit miles from 2018 through 2023.[76]

[75] For small fires, SCE used ODRM "CMI per circuit" data from fire-related cause codes with major event days (MEDs) excluded, as the basis of a CMI consequence distribution for small fires. The two underlying assumptions in this methodology are that (a) small fires will not be enough to trigger MEDs, and (b) small fires are generally individual circuit outage events.
For large fires, SCE used ODRM "CMI per day" data from fire-related causes codes with MEDs included, as the basis of a CMI consequence distribution for large fires. The two underlying assumptions in this methodology are that (a) large fires may be enough to trigger MEDs, and (b) large fires are most likely to be events that impact multiple circuits. In general, SCE expects that this methodology will understate CMI/fire for large fires that span multiple days, but will overstate CMI/fire for large fires where multiple fires burn on the same day. For purposes of RAMP, SCE assumed that these two factors will generally offset each other and result in a reasonable reliability consequence distribution for large fires.
[76] The 2,426 circuit miles identified includes four circuit miles completed prior to the GS&RP filing (A. 18-09-002), 592 miles described in the GS&RP filing through 2020, and 1,830 miles estimated to be required

3. Branch Line Fusing in HFRA

This metric tracks the number of fusing locations addressed by M8 (Fusing Mitigation) in HFRA. This mitigation measure aims to reduce ignitions when faults occur on distribution branch lines in HFRA. Because Fusing Mitigation encompasses all branch lines for portions of circuits that traverse HFRA, it represents another measure for hardening distribution circuits in HFRA. SCE's plan, at this time, is to address 15,613 fuse locations from 2018 through 2020,[77] by installing or replacing fuses on branch lines with faster acting current-limiting type fuses.

for reconductoring for 2021-2023. The 2021-2023 estimate will be reviewed and potentially revised prior to SCE's 2021 GRC application.

[77] Please see discussion at Section IV regarding Fusing Mitigation (M8).

IX. Appendix 1: Long Term Analysis of M1 – Wildfire Covered Conductor Program

Long-lived assets that are installed during the 2018-2023 RAMP period continue to operate and provide risk reduction benefits for many decades afterward. To provide an illustrative example of capturing the long-term benefits of such assets, SCE piloted a limited study focusing on covered conductor. Use of covered conductor is represented as M1 (Wildfire Covered Conductor Program).

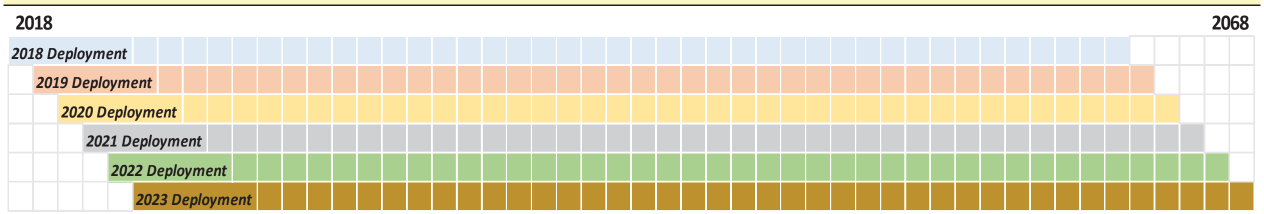
The RAMP analysis is extended out to 50 years to estimate the full benefit that the covered conductor assets provide over their useful life.

For purposes of this limited study, SCE made the following simplifying assumptions:

- 45 years of useful life for the deployments made each year during the RAMP period;
- No degradation occurring during the 45-year period;
- No benefits occurring after the 45-year period;
- No discounting of costs or benefits; and,
- M1 is run as a stand-alone portfolio with no other mitigations / controls.[78]

Figure IX-1 illustrates the full timeline when covered conductor is deployed during the RAMP period:

Figure IX-1 – Deployment of M1 (Wildfire Covered Conductor Program)

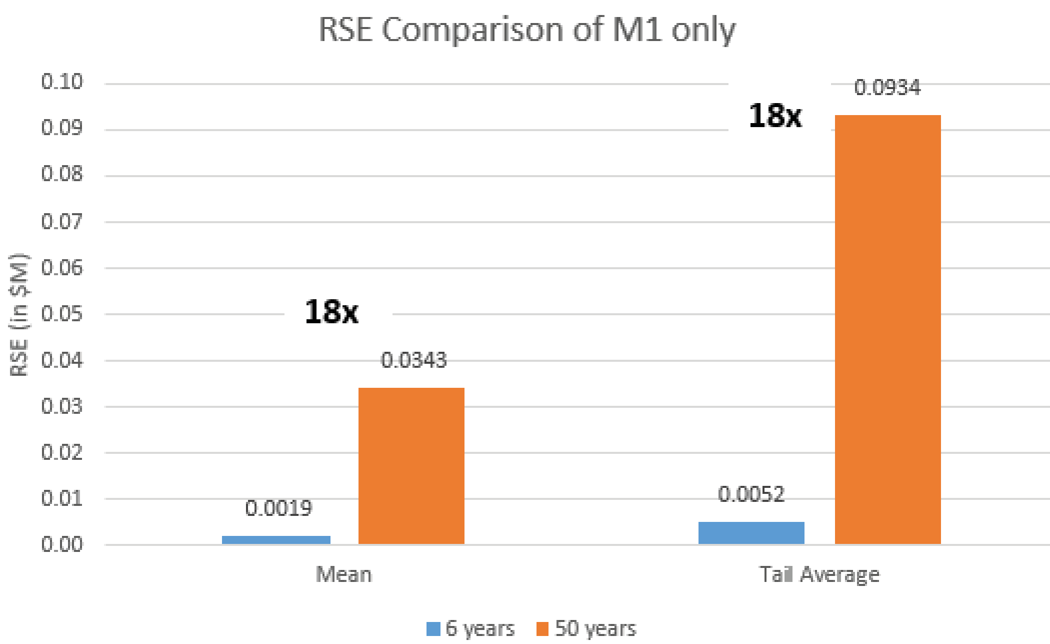


The chart below illustrates the Risk Spend Efficiency (RSE) for covered conductor (M1) for the 6-year RAMP period and the RSE for a 50-year period. The chart includes comparisons using both mean and tail average results.

[78] See Chapter 2 - RAMP Model Overview, Section 3, for discussion on scenarios with multiple mitigations.

Compared to the 6-year RAMP period analysis, the long-term RSE increases approximately 18 times on a mean basis, and increases approximately 18 times on a tail-average basis. This is shown in Figure IX-2.

Figure IX-2 – Short and Long-Term RSE Comparison of M1



For additional detail on performing long-term risk analyses, please see Chapter 8 (Hydro Asset Failure), Appendix 1. In that Appendix, SCE pilots a full long-term evaluation on the entire Hydro Asset Safety chapter, and includes more robust discussion on the impacts involved in modeling risk and mitigations beyond the RAMP period.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Underground Equipment Failure

Chapter 11

Rosemead CA
November 15, 2018

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Tables

I. Executive Summary

A. Overview

In this chapter, we evaluate the risk to SCE, its electrical system, and the public resulting from underground electrical equipment failing. SCE has constructed a risk bowtie to quantify the potential safety, reliability, and financial consequences resulting from this risk.

SCE's Proposed Plan for this risk encompasses elements of SCE's Distribution Infrastructure Replacement (DIR) program, including the existing Worst Circuit Rehabilitation Program, the existing Cable in Conduit Replacement Program, the existing Underground Oil Switch Replacement Program, and a new Covered Pressure Relief and Restraint (CPRR) program. The existing programs directly influence the frequency of this risk. The new program reduces the severity of the impact when the risk does occur. SCE also contemplated two alternative plans that include adding a new mitigation aimed at further reducing the frequency of occurrence.

B. Scope

The scope of this chapter is defined in Table I-1.

Table I-1 – Chapter Scope

IN SCOPE	Primary distribution UG electrical equipment failure that could potentially lead to a vault or manhole explosion event.
OUT OF SCOPE	• Events initiated by human performance (which would be covered in Chapter 7 - Employee, Contractor, and Public Safety); • Events initiated by UG structure deterioration and failure;[1] • Failure of padmounted UG electrical equipment;[2] • Equipment failures leading to explosions within structures without a manhole lid; and, • Secondary distribution systems.[3]

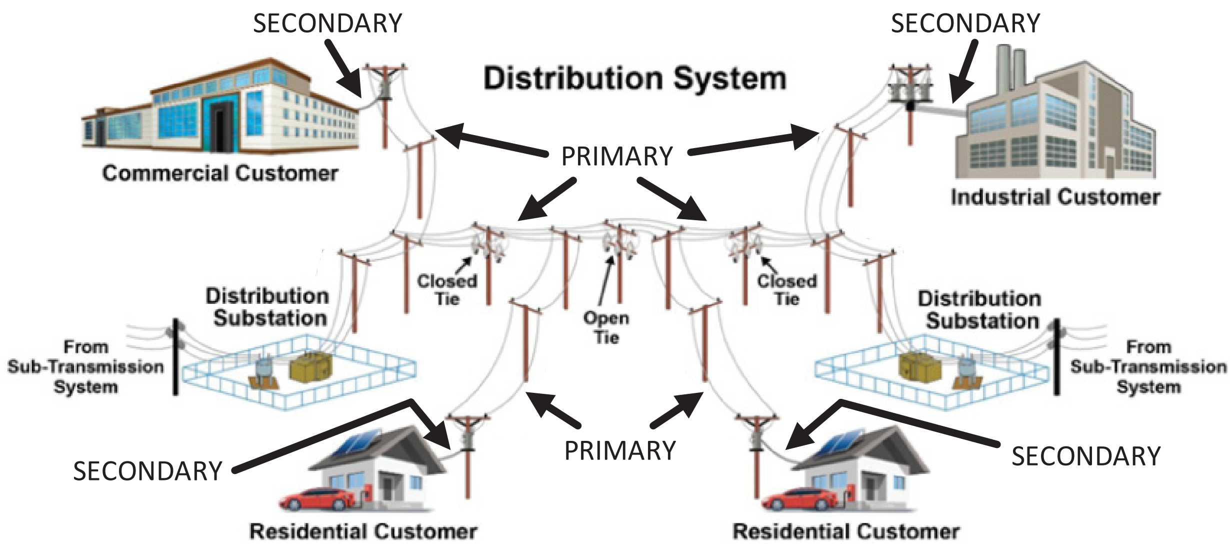
[1] Structural failure of an underground structure itself, such as concrete deteriorating in a vault that has a manhole cover, is not included in this analysis because it is not a driver for the triggering event.

[2] SCE identifies surface-mounted equipment ("padmounted") such as switches, transformers and capacitor banks as part of its underground system. However, failure of such equipment is not likely to result in an explosion within a subsurface structure. Accordingly, failures of such padmounted equipment are not included in this analysis.

[3] Secondary distribution systems are not included in this analysis, because the vast majority of SCE's secondary distribution systems are radial systems; based on available data, such facilities typically are not associated with underground explosions. SCE's Long Beach secondary is an exception to this statement, as we have experienced events in that area in the past. Further discussion is provided in Section II.A – Background.

This scope includes equipment failures on SCE's primary distribution system and excludes failures on SCE's secondary distribution systems. The term "primary" refers to the high-voltage side of distribution transformers, typically 4 kV, 12 kV or 16 kV. The term "secondary" refers to the low-voltage side of distribution transformers, typically 480 V or less. Figure I-1 below is a simplified diagram of the SCE distribution system illustrating the distinction between primary distribution and secondary distribution. While this figure shows overhead distribution facilities, the concepts equally apply to underground distribution facilities as well.

Figure I-1 – Illustration of Typical Primary and Secondary Distribution Systems



The drivers of this risk include the failure of equipment installed on SCE's primary distribution system in subsurface installations. The two outcomes resulting from this risk include (1) the uncontrolled release of energy from a manhole or vault ("explosion"), and (2) contained or controlled ("non-explosion") energy events.

It is important to note that this risk includes explosions explicitly within underground vaults or manholes. SCE recognizes that there are other types of subsurface structures that can also have risks related to equipment-related failures and explosions. For additional discussion, see the data collection discussion in Section VIII.B of this chapter.

C. Summary Results

Table I-2 provides summary information on the controls and mitigations contemplated and included in this chapter, as well as the results of SCE's risk evaluation included in this chapter, using SCE's Multi Attribute Risk Scoring (MARS) framework. SCE discusses in detail in Sections V, VI, and VII the reasons why SCE is recommending the Proposed Plan at this time, rather than Alternative Plan #1 or Alternative Plan #2.

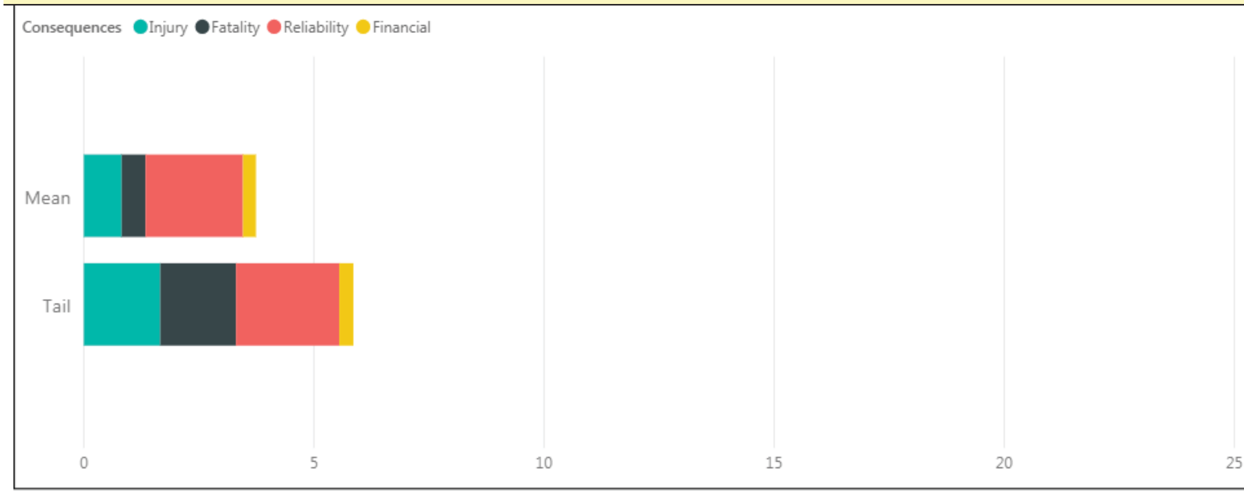
Table I-2 – Summary Results (Annual Average over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Cable Replacement Programs (WCR)	X	X	X
C2	Cable Replacement Programs (CIC)	X	X	X
C3	UG Oil Switch Replacement Program	X	X	X
M1	Cover Pressure Relief and Restraint (CPRR) Program	X		
M2	BURD Transformer Replacement			X
Mean (MARS)	*Cost Forecast ($ Million)*	$191.1	$179.8	$180.3
	Baseline Risk	3.7	3.7	3.7
	Risk Reduction (MRR)	0.61	0.48	0.54
	Remaining Risk	3.1	3.3	3.2
	Risk Spend Efficiency (RSE)	0.0032	0.0026	0.0030
Tail Average (MARS)	*Cost Forecast ($ Million)*	$191.1	$179.8	$180.3
	Baseline Risk	5.9	5.9	5.9
	Risk Reduction (MRR)	0.91	0.61	0.69
	Remaining Risk	5.0	5.3	5.2
	Risk Spend Efficiency (RSE)	0.0048	0.0034	0.0038

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-2 below illustrates the baseline risk associated with underground equipment failure. The mean result is the average result across all simulations. The tail-average result is the average of the most extreme ten percent of simulations. In other words, it indicates lower-probability, higher-impact events. The color coding represents the contribution from each of the risk attributes analyzed within this RAMP report. This figure shows that reliability is the largest impact on a mean basis, while safety impacts become a much larger share of the risk on a tail-average basis.

Figure I-2 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

SCE's electric distribution system covers 50,000 square miles and runs throughout the communities we serve. Electrical components, such as cable, conductor, transformers, switches, etc., are installed above or underneath nearly every street in SCE's service territory. This equipment is necessarily located adjacent to schools, residential neighborhoods, shopping malls, community centers, and entertainment venues. In the SCE electric distribution system approximately one-third of primary conductor miles are installed underground.[4]

As described in SCE's Test Year 2018 General Rate Case (GRC),[5] the equipment installed in SCE's underground vaults can degrade or deteriorate as a result of age, wear, and environmental factors. In addition, underground equipment is inadvertently damaged when vaults and manholes are used by members of the public to improperly dispose of liquids or material such as motor oil, cleaning solvents, etc.

As aging electrical equipment degrades over time, its probability of in-service failure increases. However, underground equipment has unique risks associated with in-service failures because the equipment is contained within relatively small underground vaults or manholes. As a result, underground equipment failures can result in an explosion of combustible gases that build up within the structure. These explosions can forcibly dislodge a vault or manhole cover from its frame, damage streets, and injure the public or utility workers.

SCE, like many other electric utilities, has experienced underground equipment failures resulting in explosions, fires, and smoke events. An article in T&D World states: "For most utilities, maybe only one in 1,000 manholes has an event in a year. But with so many manholes in the U.S., this adds up to approximately 2,000 manhole events per year, or 5.5 events per day."[6]

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[4] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 21, Table III-5; p. 48, line 1.

[5] See A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 7-9.

[6] See http://www.tdworld.com/intelligent-undergrounding/where-theres-smoke. This statistic, while widely reported, is also a very high-level approximation, and includes smoke and fire incidents as well as explosion incidents. For comparison, the SCE system has approximately 40,000 vaults and manholes, and SCE's modeled incidence rate is 20 explosion events per year. Therefore, the apparent incidence rate in the SCE system is roughly equivalent to "1 explosion per 2000 vaults/manholes per year." This suggests that SCE's experience is comparable on an order of magnitude basis to the industry's experience in terms of underground incident frequency. The SCE-specific explosion incidence rate is discussed in greater detail in the "Outcomes & Consequences" section later in the Chapter.

Vault explosions have occurred in SCE's service territory, including but not limited to these recent events.[7]

- SCE's Long Beach District, July 2015 – During outages on two separate days, SCE's system experienced as many as eight vault events (i.e., reports of fire or smoke) and two vault explosions, according to City of Long Beach 911 records.[8]
- SCE's Whittier District, July 20, 2016 – Cable accessory on a distribution circuit failed in service. This resulted in a vault cover being displaced and caused significant damage to a passing vehicle and injury to the vehicle occupant.
- SCE's Huntington Beach District, September 28, 2016 – Cable on a distribution circuit failed in service. This resulted in the vault casting and ladder, portions of the vault vent pipes, and the lid of an adjacent pull box all being displaced.
- SCE's Covina District, November 5, 2016 – Cable on a distribution circuit failed in service. This resulted in a manhole lid being displaced, causing damage to both the manhole lid and the street. The damage from this event is shown in Figure II-4.
- SCE's Covina District, October 23, 2017 – Cable on a distribution circuit failed. This resulted in a manhole lid being displaced, causing damage to the structure, the street, multiple vehicles, and nearby homes.

B. Risk Bowtie

To evaluate the risk of underground equipment failure within SCE's system, SCE has constructed an UG Equipment Failure risk bowtie as shown in Figure II-1. The bowtie presents the risk drivers, outcomes, and consequences with additional detail on each provided in the sections below.

[7] See http://cpuc.ca.gov/AnnualReports for the California Public Utilities Commission Annual Report to the Legislature for details on events reported by California utilities, including reportable underground vault/equipment failures.

[8] The Commission opened an investigation, I.16-07-007, on the Long Beach incident and issued its decision in D.17-09-024. SCE is in the process of improving the Long Beach secondary network system as directed in the Commission's Decision. The Long Beach secondary network makes up a very small percentage of SCE's total underground system, and is not the focus of the Underground Equipment Failure risk as evaluated in this chapter. However, the damage that resulted from the Long Beach incident is an important example of the risks associated with the failure of equipment installed in an underground electrical system.

Figure II-1 – Risk Bowtie

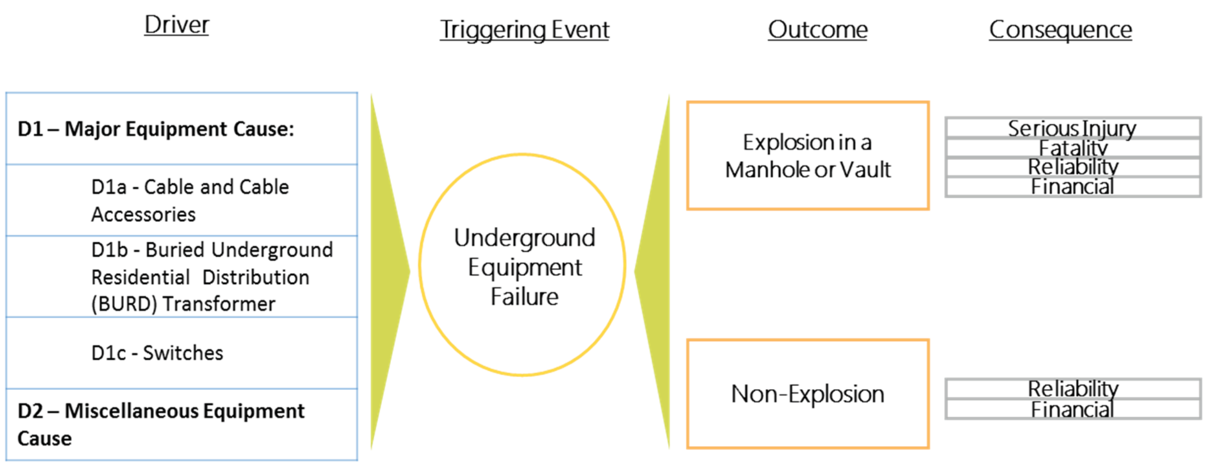


Figure II-2 shows the 2018 projected frequency for drivers that in aggregate compose the triggering events for this risk. Drivers and sub-drivers are described in detail in the section below.

Figure II-2 – 2018 Projected Driver Frequency[9]

Name	Freq	Frequency
D1 - Major Equipment Cause	1877	
D2 - Miscellaneous Equipment Cause	28	

C. Driver Analysis

SCE identified two different categories of drivers on its primary distribution system: D1 (Major Equipment Cause), and D2 (Miscellaneous Equipment Cause).

SCE used its Outage Database and Reliability Metrics (ODRM) system to identify driver frequencies. The ODRM system collects information on all distribution interruptions such as outage location, duration, cause, and number of customers impacted. SCE uses this information to calculate system reliability metrics such as System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).

[9] Please refer to WP Ch. 11, pp. 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

1. D1 – Major Equipment Cause

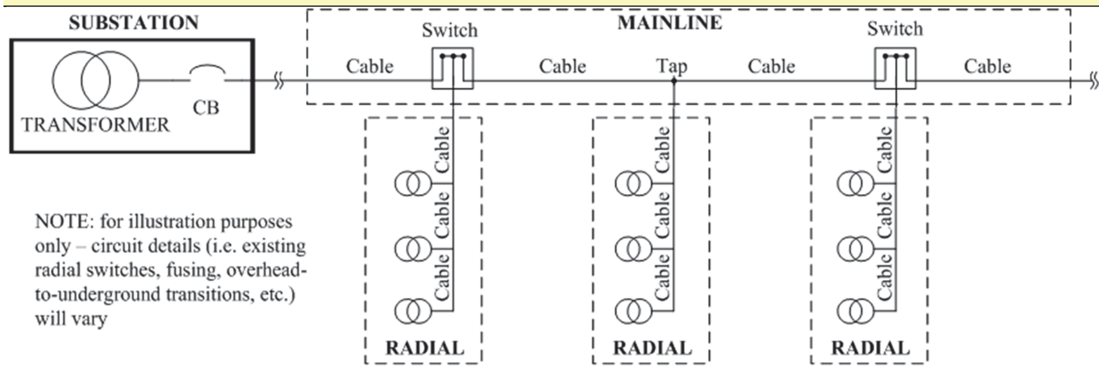
The first category of drivers is identified as “Major Equipment Cause” and includes the major types of underground equipment associated with significant underground failures, including failures of Cable and Cable Accessories, Buried Underground Residential Distribution (BURD) Transformers, and UG Switches.

a. D1a – Cable and Cable Accessories

This sub-category includes in-service failures of distribution cable and related cable accessories such as elbows, junction bars, and splices.

D1a includes the failure of primary voltage distribution cable in both mainline and radial applications. Figure II-3 illustrates mainline and radial cable on a typical distribution circuit. Failure of mainline cable tends to impact more customers, where radial cable failures are isolated to fewer customers.

Figure II-3 – Mainline and Radial Cable Illustrated on a Typical Underground SCE Circuit



The largest population of underground cable installed on SCE’s primary system is known as cross-linked polyethylene (XLPE) cable. This cable type was SCE’s standard primary distribution cable installed between years 1970 through 1999, and represents approximately half of all primary voltage underground distribution cable installed in the SCE system.[10] For older cable, breakdown of the insulation over time causes cable failure. Typically, external moisture around the cable penetrates through the polyethylene insulation, causing electrical tracking along voids and contaminants in the insulation and forming patterns that look like “trees.” This phenomenon of “water treeing” is a common cause of underground cable failure, particularly for XLPE cable.[11] Heat from the electricity running through the cable

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[10] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 21, Table III-5.
[11] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 19, lines 21-26.

contributes to thermal decomposition of polymers. This can lead to the generation of combustible gases.[12]

When a cable fails, electricity breaks through the insulation and results in a fault. This fault condition causes an upstream protective device (such as a fuse, automatic recloser, or substation circuit breaker) to operate and cut off power to all customers downstream of the protective device. This fault condition can also release a large amount of energy and, in extreme cases, lead to outcomes such as an explosion in a vault or manhole.

When a cable accessory fails, the resulting consequences can be very similar to the consequences of cable failures themselves. For this reason, SCE has combined cable and cable accessories together for this analysis.

Based on 2015-2017 ODRM data, SCE's system has experienced an annual average of 1,399 failures of cable and cable accessories (approximately 76% of the total annual observed UG Equipment Failures). Approximately 40% of these 1,399 failures are mainline cable failures, and approximately 60% are radial cable failures.

b. D1b – Buried Underground Residential Distribution (BURD) Transformer

This sub-category includes in-service failures of UG equipment known as BURD transformers. Like all distribution transformers, BURD transformers step down voltage from primary voltage levels (typically 4 kV, 12 kV or 16 kV) to voltages utilized by end-use customers. BURD transformers are designed to be used in subsurface applications such as vaults and manholes. Figure II-4 shows a typical BURD transformer installed within an underground vault on SCE's system.

[12] "…intensive thermal decomposition of polymeric material during the development of a manhole event can take the form of either combustion or pyrolysis. The most severe consequences of manhole events are caused by generation of combustible gas during thermal decomposition of polymers." Zhang L., Boggs S. (2009) The electro-chemical basis of manhole events. *IEEE Electrical Insulation Magazine,* 5:25, p. 27. *available at* https://eprcable.ims.uconn.edu/wp-content/uploads/sites/857/2014/09/manhole.pdf

Figure II-4 – BURD Transformer (left) installed in an SCE underground structure (right)

BURD transformer failures can be catastrophic in nature.[13] To illustrate, Figure II-5 shows a picture of a catastrophically failed BURD transformer. In this picture, the top of the transformer shows significant damage caused when the transformer collided with the concrete vault ceiling. The transformer was launched upward when the core and coil were ejected out of the bottom of the transformer housing during the equipment failure.

Figure II-5 – D1b (BURD Transformer): Catastrophic Failure

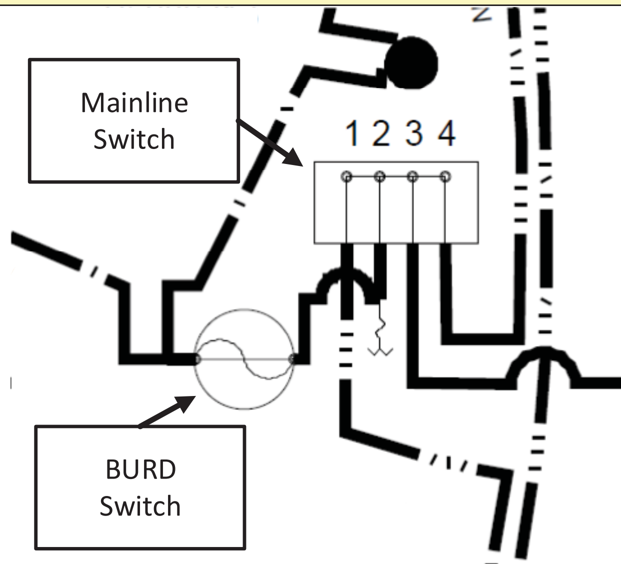
[13] Generally speaking, SCE uses the term “catastrophic” to mean a sudden and complete failure of a piece of electrical distribution equipment associated with an uncontrolled release of energy.

Based on 2015-2017 ODRM data, SCE's system has experienced an average of 328 BURD transformer failures per year (approximately 18% of total annual observed UG Equipment Failures).

c. D1c - Switches

This sub-category includes the in-service failure of subsurface equipment known as switches. Similar to distribution cable, distribution switches will typically fit into one of two types – mainline switches and BURD switches. Mainline switches are typically used to divide mainline circuits into sections or blocks. BURD switches are typically used to separate mainline and radial portions of a circuit. Figure II-6 graphically represents a mainline switch and a BURD switch on a typical SCE underground distribution circuit. Overall, SCE has approximately 16,000 mainline switches installed on its underground system; approximately 1,000 of these are oil-filled switches. SCE also has approximately 17,000 BURD switches installed on its underground system; roughly half of these are oil-filled switches.

Figure II-6 – Illustration of Mainline Switch and BURD Switch



Oil-filled switches are a particular concern to SCE. When an oil-filled switch ages, there can be an increase in dissolved explosive gases within the switch oil. These dissolved gases increase the risk of explosion. Failures of oil-filled equipment can damage adjacent electrical equipment (e.g., cable, transformers, and other switches). This increases the duration of the outage and the scope of restoration. Property damage and injuries can also result from oil switch failures. As stated in our 2018 GRC, SCE plans to continue to preemptively replace oil-filled subsurface switches with gas-filled or vacuum switches until all such oil-filled switches have been replaced.[14]

Based on three years of historical data (2015-2017), SCE's system has experienced an average of 90 switch failures per year (approximately 4.9% of total annual observed UG Equipment Failures). Approximately 70% of these 90 failures are BURD switch failures, for a BURD switch annual failure rate of approximately 0.4% of the entire BURD switch population. The remaining 30% of these 90 failures are mainline switch failures, for a mainline switch annual failure rate of approximately 0.2% of the entire mainline switch population. SCE attributes the lower annual failure rate of mainline switches to its existing infrastructure replacement program. This program has been replacing aging mainline oil-filled switches every year since at least 2005.[15] As we describe in our 2018 GRC, at this time SCE intends to place greater focus on pre-emptively replacing radial switches as opposed to mainline switches.[16]

2. D2 – Miscellaneous Equipment Cause

The second category of drivers is identified as D2 (Miscellaneous Equipment Cause). This includes all applicable underground equipment failures not included in D1 (Major Equipment Cause). These can include fuses, other isolation devices, underground capacitor banks, and other miscellaneous equipment. Due to the relatively small number of occurrences of equipment failures among these types of equipment, they were grouped together for analytical purposes within this analysis.

Based on 2015-2017 ODRM data, SCE's system has experienced an average of 28 failures per year for equipment that does not fit into driver categories D1a-D1c (approximately 1.5% of total annual observed UG Equipment Failures).

D. Triggering Event

The triggering event is the in-service failure of UG electrical equipment within an SCE underground structure. Based on 2015-2017 ODRM data, in total, SCE is experiencing an average triggering event frequency of 1,845 UG Equipment Failures per year.

To account for equipment aging, SCE modeled failures due to D1 – Major Equipment Cause with an approximately 3% annual growth rate.[17] SCE modeled no annual growth in failures due to D2 - Miscellaneous Equipment Cause because of the relatively small size of the driver

[14] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 6-7.
[15] See A.10-11-015, Exhibit SCE-03, Vol. 3, p. 44, Table II-10.
[16] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 7-10.
[17] Please refer to WP Ch. 11, pp 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

category and the wide variety of equipment that could be included in this category. The resulting triggering event frequency for years 2018 through 2023 is shown in Table II-1.

Table II-1 – Forecast Annual Triggering Events[18]

Full Name	2018	2019	2020	2021	2022	2023
Underground Equipment Failure						
Baseline	**1,904.56**	**1,966.07**	**2,029.60**	**2,095.21**	**2,162.97**	**2,232.96**
Driver						
D1 - Major Equipment Cause	1,876.56	1,938.07	2,001.60	2,067.21	2,134.97	2,204.96
D2 - Miscellaneous Equipment Cause	28.00	28.00	28.00	28.00	28.00	28.00
Total	**1,904.56**	**1,966.07**	**2,029.60**	**2,095.21**	**2,162.97**	**2,232.96**

E. Outcomes & Consequences

Figure II-7 shows the likelihood of each of the two outcomes occurring when there is an in-service failure of UG electrical equipment within an underground structure.

Figure II-7 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Explosion in a Manhole or Vault	1.1 %	
O2 - Non-Explosion	98.9 %	

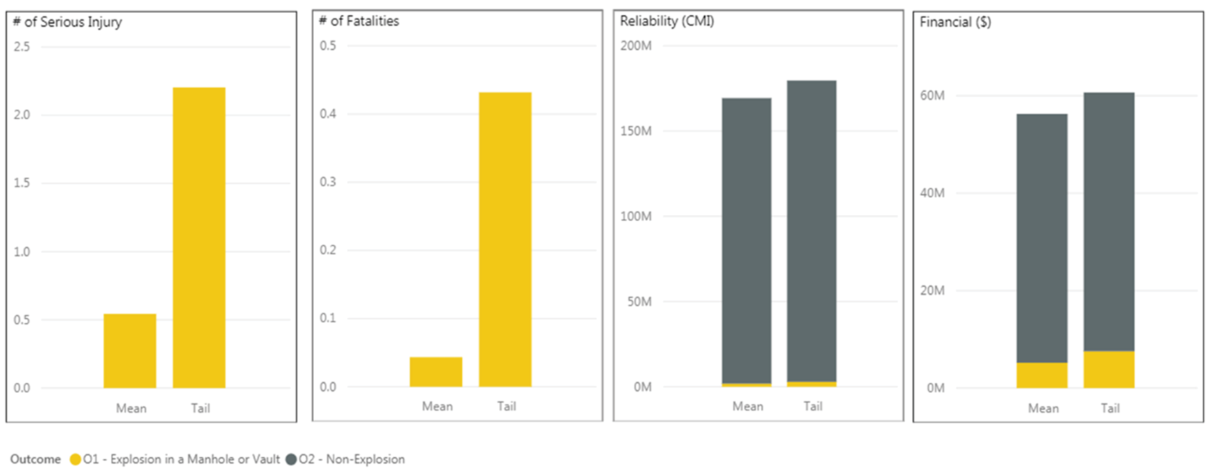
SCE relied upon historical data to determine the likelihood of each outcome occurring. Prior to 2018, data related to underground equipment failures within a vault or manhole was captured in Repair Order form. SCE had first attempted to extract the necessary data from these forms, but our ability to reasonably access this data proved to be insufficient for RAMP

[18] Refer to WP Ch. 11, pp 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

modeling purposes.[19] As such, in 2018 SCE implemented a new data tracking process called the Cover Pressure Relief and Restraint (CPRR) Event Tracker. SCE used this data to determine outcome likelihood for this risk.[20]

Figure II-8 illustrates the composition of the modeled baseline risk in terms of each consequence dimension, shown in natural units, on a mean and tail-average basis. The sections that follow detail the inputs used to derive these results.

Figure II-8 – Consequences by Outcome



1. O1 - Explosion in a Manhole or Vault

For this RAMP analysis, SCE uses the term "explosion" to refer to the uncontrolled release of energy from an underground vault or manhole caused by equipment failure on the distribution system. This outcome can result in displaced manhole covers, other pieces of flying debris, and/or significant damage to roadways or sidewalks. All of these can pose a risk of serious injury or fatality to the public. For example, Figure II-9 shows the damage to an SCE manhole and a public street associated with a vault explosion triggered by a failed distribution cable (D1a).

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[19] A Repair Order (RO) is a form initiated by field personnel as they first respond to circuit interruptions or other trouble calls. The form is used by field personnel to identify the type and size of needed repair crews, and to provide a detailed list of material and equipment required to make repairs. SCE found that the historical RO forms did not explicitly classify underground equipment failures on a basis that could be mapped to this RAMP bowtie. In light of this uncertainty, it was not possible to determine credible outcome percentages based on the available RO data.

[20] The CPRR Event Tracker is a system that began collecting underground explosion data in 2018. The CPRR Event Tracker helps SCE track underground structure explosion data across all underground structures in the SCE system. Data for the tracker is reported from field crews through SCE's Grid Operations organization to the Underground Structures Management group, where it is uploaded into the CPRR Event Tracker itself.

Figure II-9 – Illustration of Explosion Outcome (O1) due to Cable Driver (D1a)

Based on SCE's CPRR Event Tracker Data, SCE has observed a rate of approximately 20 explosion events per year in underground vaults or manholes. With a triggering event frequency of 1,845 equipment failures per year, this results in an outcome percentage of 1.1% of underground equipment failures that result in an explosion in an underground vault or manhole (O1).[21]

Table II-2 summarizes the baseline consequences across risk dimensions for Outcome 1, showing mean and tail risk. The table also summarizes the source data used to develop consequence distributions for this outcome.

[21] SCE recognizes that the CPRR Event Tracker Data – which includes only partial year 2018 data – is not a large data set from which to extrapolate annual expected values of vault or manhole explosions. Going forward, SCE anticipates that this data set will become more robust as additional data is gathered.

Table II-2 – Outcome 1 (Explosion from a Vault or Manhole): Consequence Details

Outcome 1		Consequences			
		Serious Injury	Fatality	Reliability (CMI)	Financial
Model Inputs	*Data/sources used to inform model inputs*	Incidents involving SCE underground equipment that resulted in injuries in 2018; Incidents listed in CPUC annual reports 2015-2017; Developed SME estimate of one serious injury in two years.	A SME estimate was developed to estimate the annual consequences to be one fatality in 25 years.	SCE Evaluated actual underground equipment failure events based on analysis of SCE ODRM Database from 2015-2017.	Average cost of equipment repair resulting from underground equipment failure explosion events.
Model Outputs *(Annual Average)*	NU - Mean	0.5	0.04	1,835,142	$5,194,075
	NU - Tail Avg	2.2	0.43	2,886,326	$7,552,824

2. O2 - Non-Explosion Events

The majority of underground equipment failures do not result in an explosion from a vault or manhole. For purposes of this analysis, these safe failure events are referred to as "non-explosion" events. In such instances, the system operates as designed, and the energy associated with these equipment failures does not exceed the system's capacity to contain or control it.

Based on all available CPRR Event Tracker data, SCE has concluded that 98.9% of UG Equipment Failures result in non-explosion event outcomes (O2). This is equivalent to an expected value of approximately 1,825 non-explosion events per year throughout SCE's service territory.

Table II-3 summarizes the baseline consequences across risk dimensions for Outcome 1, showing mean and tail risk. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-3 – Outcome 2 (Non-Explosion Events): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	N/A	N/A	SCE Evaluated actual underground equipment failure events based on analysis of SCE ODRM Database from 2015-2017.	Average cost of equipment repair resulting from underground equipment failure non-explosion events.
Model Outputs *(Annual Average)*	NU - Mean	N/A	N/A	167,463,798	$51,071,135
	NU - Tail Avg	N/A	N/A	176,712,950	$53,119,027

III. Compliance & Controls

SCE has programs and processes in place today that serve to reduce the frequency of this risk event from occurring, or the impacts of the risk event should it occur. These activities are summarized in Table III-1, and discussed in more detail below.

Table III-1 – Inventory of Compliance & Controls[22]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Underground Detail Inspections (UDI) and Underground Preventive Maintenance	Not Modeled	Not Modeled	Not Modeled	$0	$37
C1	Cable Replacement Programs (WCR)	D1a	O1, O2	R	$135	$0
C2	Cable Replacement Programs (CIC)	D1a	-	-	$74	$0
C3	UG Oil Switch Replacement Program	D1c	-	-	$19	$0

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 - Underground Detail Inspections (UDI) and Underground Preventive Maintenance

1. Description

SCE's UDI and Underground Preventive Maintenance are activities included under SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of General Orders (GO) 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety and maintains system reliability; and (3) delivers overall greater safety value for each dollar we spend by allowing SCE to focus its limited resources on higher-priority risks.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and how it potentially impacts safety and reliability. We consider various factors, including the facility or equipment itself, loading, location, accessibility, climate, and direct or potential impact on safety or reliability. DIMP enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's direction under GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

[22] Please refer to WP Ch. 11, pp. 11.3-11.8 *(RAMP Mitigation Reduction Workpaper)* and WP Ch. 11, pp 11.9-11.14 *(Mitigation Effectiveness Workpaper).*

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify and rate conditions observed considering the factors discussed previously. Highest priority items requiring immediate action are assigned Priority 1. Priority 2 items do not require immediate action, but require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired or temporarily repaired and reclassified as a lower priority item. Priority 3 items are lower priority items that involve little or no safety or reliability risk. SCE responds to Priority 3 conditions by taking action at or before the next detailed inspection. These actions may include re-inspecting, reassessing, or repairing. These maintenance priorities are also utilized by Troublemen when responding to trouble calls and emergency situations.

B. C1 - Cable Replacement Programs (Worst Circuit Rehabilitation)

1. Description

SCE's Worst Circuit Rehabilitation (WCR) Program[23] addresses problems of aging or obsolete underground mainline cable, and mitigates the negative consequences of in-service cable failures on system reliability and associated safety risks. The WCR Program focuses on circuits that disproportionately contribute to system reliability, by ranking circuits based on three years of historical reliability performance data and targeting the worst performing 1% of circuits for detailed consideration. Circuit rehabilitation typically involves replacing aging mainline cable on each circuit. The WCR Program also adds circuit enhancements such as automation, automatic reclosers, branch line fuses, and fault indicators.

The current deployment plan for this program includes replacing approximately 1,900 conductor miles from 2018 through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The WCR Program impacts Driver D1a (Cable and Cable Accessories). The WCR Program replaces aging mainline cable and cable accessories prior to failure, and SCE's ODRM indicates that approximately 40% of cable-related failures are on mainline cable.

3. Outcomes & Consequences Impacted

The WCR Program targets mainline cable that has both a higher probability of failure and a higher reliability consequence of failure. Therefore, the WCR Program impacts reliability consequences associated with underground equipment failures.

[23] Please see A.16-09-001, Exhibit SCE-02, Vol. 8 for a detailed description of the program and its history.

C. C2 - Cable Replacement Programs (Cable-In-Conduit)

1. Description

SCE's Cable Life Extension (CLE) Program and Cable-in-Conduit (CIC) Replacement Program collectively and in concert, address the increasing problems of radial cable failures.

The CLE Program consists of two activities. The first activity is a partial discharge testing activity ("cable testing") which identifies those radial cable segments at greatest risk for imminent failure. The second activity is a cable rejuvenation activity ("cable rejuvenation") that provides life extension benefits by improving the insulation characteristics of aged radial cable. This program does so by physically injecting a silicone-based fluid along the strands of aging underground radial cable. This fluid migrates into the conductor insulation, modifying its chemistry and improving its dielectric strength. Both the cable testing and the cable rejuvenation activities identify cable segments in scope for the CIC Replacement Program, which replaces cables that fail testing, as well as cables that cannot be remediated through cable rejuvenation.

The current deployment plan for this control includes replacement or rejuvenation of approximately 1,600 conductor miles of radial cable through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The CLE and CIC Replacement Programs impact Driver D1a (Cable and Cable Accessories). These two programs either extend the life of aging radial cables or replace radial cables and cable accessories prior to failure. SCE's ODRM indicates that approximately 60% of cable-related failures are on radial cable.

3. Outcomes & Consequences Impacted

In general, the CLE and CIC Replacement Programs target aging radial cable based on probability of failure and not impact of failure. Therefore, the CLE and CIC Replacement Programs will not impact outcomes or consequences associated with failures.

D. C3 - Underground Oil Switch Replacement Program

1. Description

SCE's Underground (UG) Oil Switch Replacement Program replaces oil-filled switches in underground structures which are approaching the end of their service lives and pose a threat to both system reliability and public and employee safety. SCE plans to continue its program of preemptively replacing oil-filled subsurface switches with gas or vacuum switches until all oil-filled switches have been replaced. In the recent past, program efforts have focused primarily on mainline oil-filled switches. Going forward, SCE intends to focus pre-emptive switch replacements more on radial switches than on mainline switches because of the greater failure rate of BURD switches and the relatively older age of the existing BURD switch population.[24]

The current deployment plan for this control includes replacing approximately 1,500 oil switches through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The Underground Oil Switch Replacement Program impacts D1c (Switches). The program replaces both mainline and radial subsurface oil-filled switches prior to failure.

3. Outcomes & Consequences Impacted

In general, the Underground Oil Switch Replacement Program targets specific switches based on probability of failure, rather than impact of failure. As a result, SCE has modeled the program as having no impact on the outcomes or consequences associated with underground equipment failures.

[24] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 7-10.

IV. Mitigations

Besides the controls detailed in Section III, SCE has identified potential new and innovative ways to mitigate this risk. These mitigations are summarized in Table IV-1, and discussed in more detail thereafter.

***Table IV-1 – Inventory of Mitigations*[25]**

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted
M1	Cover Pressure Relief and Restraint (CPRR) Program	-	O1	S
M2	BURD Transformer Replacement	D1b	-	-

Consequence abbreviations: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period.

A. M1 - Cover Pressure Relief and Restraint (CPRR) Program

1. Description

The CPRR Program is a new mitigation program that would deploy a new vault lid technology on SCE's system. Standard unrestrained vault and manhole covers can become projectiles during explosion events. This mitigation would involve replacing standard vault and manhole covers with new technology covers that are designed to both relieve built-up pressure and restrain the cover during explosion events.

SCE has been building expertise in this type of mitigation through research, targeted deployment, and ongoing pilot efforts involving vault lid technologies. For example, SCE began installing tethers on vaults in Long Beach in late 2015, following the vault lid displacement events earlier in that year. Further evaluating these vault lid tethers led to developing a more robust engineering design concept involving vault lid venting and restraint technology in 2016. SCE began piloting this concept in select areas of the system in 2017, and updated underground standards for new construction activities to incorporate this technology. In late 2017 and 2018, SCE began piloting proactive vault lid replacements; this work in ongoing.

The CPRR Program would target the installation of venting and restrained vault lids in approximately 550 vaults and manholes in 2019, and approximately 1,000 vaults and

[25] Please refer to WP Ch. 11, pp. 11.3-11.8 *(RAMP Mitigation Reduction Workpaper)* and WP Ch. 11, pp 11.9-11.14 *(Mitigation Effectiveness Workpaper).*

manholes each year thereafter through 2023, for a total installation count of approximately 4,550 lids by the end of 2023. Installations would be targeted based on location-specific risk factors such as population density, proximity to schools or hospitals, congregating areas, and the nature and type of electrical equipment in the associated underground structures.

2. Drivers Impacted

The CPRR Program is consequence-focused, and would not impact any of the identified drivers.

3. Outcomes & Consequences Impacted

The CPRR Program would impact the safety consequences associated with O1 (Explosion from a Vault or Manhole). The CPRR Program involves the use of new vault lid technology that decreases the likelihood of serious injury or fatality due to a vault explosion event.

B. M2 - BURD Transformer Replacement

1. Description

This is a new mitigation program that would initiate preemptively replacing BURD transformers. SCE does not, at present, have a program targeting preemptive replacement of aging BURD transformers. In this risk analysis, BURD transformer failures were noted to be the second largest driver, with 328 transformer failure events per year at current rates. This amounts to nearly one BURD transformer failure per day in the SCE system.

SCE has approximately 82,000 BURD transformers in its inventory today. This mitigation was modeled as replacing only 100 BURD transformers per year for years 2019-2023 with like-for-like replacements. This assumed replacement rate of only 0.1% of the population each year was selected simply for illustrative purposes in this analysis.

2. Drivers Impacted

Implementing a new BURD Transformer Replacement Program would directly impact D1b (BURD Transformer). Such a program would replace aging BURD transformers prior to failure.

3. Outcomes & Consequences Impacted

A new BURD Transformer Replacement Program would target specific transformers based on the probability of failure rather than the impact of failure. As a result, SCE has modeled the program as having no impact on the outcomes or consequences associated with underground equipment failures.

V. Proposed Plan

SCE has evaluated the controls and mitigations identified in Sections III and IV above, and has developed a Proposed Plan for mitigating this risk. This elements of this Proposed Plan are shown in Table V-1 below.

Table V-1 – Proposed Plan 2018-2023 Totals

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.436	0.0007	0.531	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.221	0.0060	2.851	0.0078
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.159	0.0014	0.204	0.0019
M1	Cover Pressure Relief and Restraint (CPRR) Program	2019	2023	$ 68	$ -	0.855	0.0126	1.863	0.0274
			Total - Proposed Plan	**$1,147**	**$0**	**3.671**	**0.0032**	**5.449**	**0.0048**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

The Proposed Plan continues to deploy existing controls at specified levels over the RAMP period. This involves executing the WCR, CIC, CLE, Switch replacement, and CPRR programs. The Proposed Plan deploys proven distribution infrastructure replacement programs that help address this risk, with the largest risk reduction and the highest RSE compared to the two alternative plans.

SCE's existing controls primarily reduce the frequency of equipment failures, and in the case of the WCR Program, reduce the reliability impact of equipment failures. However, the efforts will not eliminate all in-service equipment failures. This plan also includes the Cover Pressure Relief and Restraint (CPRR) Program (M1), which would help reduce the potential safety consequences when those failures do occur.

B. Execution Feasibility

Executing the Proposed Plan is feasible. The Proposed Plan largely relies on highly mature work processes, well-understood equipment types, and established work methods. SCE has a high degree of confidence that it can execute these programs at the levels described.

SCE began piloting this concept in select areas of the system in 2017, and updated underground standards for new construction activities to incorporate this technology. In late 2017 and 2018, SCE began piloting proactive vault lid replacements. Based on results to date, SCE has a high degree of confidence in the ability to execute a larger scale CPRR program.

We will use the results of the pilot to help inform future deployment of the program. Accordingly, SCE may refine this mitigation plan in our 2021 GRC, as appropriate.

C. Affordability

This Proposed Plan is the most expensive mitigation plan that SCE considered. However, the Proposed Plan also has the highest RSE and largest risk reduction. Based on these results, the CPRR Program would enhance the overall RSE of SCE's existing portfolio of controls.

D. Other Considerations

Because this Proposed Plan consists of existing and established controls, and we have gained experience executing a pilot for CPRR equipment, SCE does not anticipate other challenges in executing this plan.

VI. Alternative Plan #1

SCE evaluated other options to address this risk. We developed Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 2018-2023 Totals

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.438	0.0007	0.538	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.240	0.0061	2.901	0.0079
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.161	0.0015	0.208	0.0019
			Total - Alternative #1	**$1,079**	**$0**	**2.839**	**0.0026**	**3.646**	**0.0034**

A. Overview

Alternative Plan #1 continues to only deploy existing controls at specified levels over the RAMP period. This involves executing the WCR, CIC, CLE, and Switch replacement. The Proposed Plan deploys proven distribution infrastructure replacement programs that help address this risk.

SCE's existing controls primarily reduce the frequency of equipment failures, and in the case of the WCR Program, reduce the reliability impact of equipment failures.

B. Execution Feasibility

As discussed in Section V, SCE has a high degree of confidence in the feasibility of deploying the existing controls in this plan.

C. Affordability

The Alternative Plan #1 is the least-cost option of the three mitigation plans. The RSE of the Alternative Plan #1 is slightly lower than the RSEs compared to the Proposed Plan and Alternative Plan #1, which suggests that it could be made more cost-effective by adding one or both of the alternative mitigations M1 (CPRR Program) or M2 (BURD Transformer Replacement).

D. Other Considerations

SCE does not currently anticipate other challenges in executing this plan.

VII. Alternative Plan #2

SCE evaluated additional options to address this risk, and developed Alternative Plan #2 as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 2018-2023 Totals

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.429	0.0007	0.525	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.178	0.0059	2.812	0.0076
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.156	0.0014	0.201	0.0018
M2	BURD Transformer Replacement	2019	2023	$ 3	$ -	0.462	0.1444	0.596	0.1861
			Total - Alternative #2	$1,082	$0	3.226	0.0030	4.134	0.0038

A. Overview

This Alternative Plan #2 includes all existing controls as described in the Proposed Plan (C1, C2, C3). Alternative Plan #2 adds a new infrastructure replacement program for BURD transformers. As indicated above, the infrastructure replacement program replaces BURD transformers with new ones on a like-for-like basis. This new mitigation, M2 (BURD Transformer Replacement), would further reduce the drivers of underground equipment failures.

More specifically, the second-largest driver of underground equipment failures – BURD transformers – is not directly addressed by any existing control within SCE's DIR programs. M2 would address this gap.

B. Execution feasibility

Because the modeled BURD Transformer replacement program targeted a relatively small number of assets (100 transformers per year), the execution feasibility of Alternative Plan #2 would be similar to that described for the Proposed Plan. SCE is familiar with replacing BURD transformers, and anticipates this program would be conceptually feasible to execute.[26]

[26] In fact, SCE replaces a small number of BURD transformers every year as part of its existing PCB Replacement Program (PCBRP) which was described in Exhibit SCE-02, Volume 8 of SCE's 2018 GRC. Conceptually, if a preemptive replacement program for BURD transformers was initiated, executing the program in a similar fashion to the existing PCBRP might be possible with as little impact as possible on design and construction resources.

C. Affordability

The cost of Alternative Plan #2 is lower than the Proposed Plan, and slightly higher than Alternative Plan #1. Similarly, the RSE of this plan is lower than the RSE of the Proposed Plan, and higher than the RSE of Alternative Plan #1. As currently modeled, M2 (BURD Transformer Replacement) might be a cost-efficient way to increase mitigation activities to address this risk. However, due to the modeling uncertainty discussed in greater detail below, further analysis is needed to justify deploying the mitigation at this point in time.

D. Other Considerations

There are certain modeling considerations that have led SCE to not pursue Alternative Plan #2 at this time.

The mitigation effectiveness modeling of the cable replacement programs (C1 and C2), the underground oil switch replacement program (C3) and of the CPRR Program (M1) are based on detailed analyses previously performed by SCE. At this time, SCE has not performed similar detailed analysis regarding replacing BURD transformers. Instead, SCE relied on much more simplified assumptions to evaluate a conceptual BURD Transformer Replacement Program. These simplified assumptions on how effective the mitigation is have not yet been fully analyzed or vetted through internal engineers and stakeholder review processes.

However, this simplified analysis has given us indications that M2 may be an effective risk mitigation measure. Going forward, SCE intends to perform more detailed risk analysis for M2 in a manner comparable to the analysis performed for C1-C3 and M1. If the results of this additional analysis continues to demonstrate that M2 has a favorable RSE compared to other programs, then SCE will introduce a BURD Transformer replacement program at that time. As applicable, SCE intends to provide an update of this additional analysis in the upcoming 2021 GRC.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has learned important lessons through this RAMP process in quantitatively modeling long-term benefits. We also gained learning in the consistency of mitigation effectiveness assumptions, and the significance of predictive accuracy for infrastructure replacement programs.

1. Quantitative Modeling of Long-Term Benefits

Quantitatively modeling infrastructure replacement programs requires that we: (a) carefully consider factors like infrastructure aging, and degradation; and (b) examine the benefits over time of near-term investments in assets with long service lives. One of the foundational pillars of SCE's Distribution Infrastructure Program is the aging of SCE's infrastructure and the long-term benefits achieved from infrastructure replacement programs. However, these benefits are not entirely addressed by RAMP analysis, which only assesses risk benefits through 2023. This impacts this RAMP chapter because of the long-life nature of the controls and mitigations discussed. Please also refer to the global discussion of this challenge in the Lessons Learned section in Chapter 1 (RAMP Overview).

2. Consistency of Mitigation Effectiveness Assumptions

It is important to have a consistent framework for determining and modeling mitigation effectiveness to appropriately compare RSEs of controls and mitigations. In the context of this chapter, SCE had performed previous detailed asset analysis of WCR, CIC, Underground Switches, and CPRR Programs. As a result, the RSEs for these controls and mitigations were based on mature analyses and had undergone internal vetting on several occasions. This type of analysis was not available for modeling the mitigation effectiveness of M2 - BURD Transformer Replacements.

Accordingly, at this time, SCE cannot be certain whether the high RSE of BURD Transformer Replacements as shown in our RAMP analysis occurred because the program would be extremely efficient at reducing risk, or because the modeling assumptions for mitigation effectiveness were overly optimistic. When interpreting these results, appropriate consideration must be given to the degrees of confidence in the underlying mitigation effectiveness modeling assumptions.

3. Predictive Accuracy for Infrastructure Replacement Programs

In general, the results show that higher levels of modeled predictive accuracy is associated with higher RSEs for infrastructure replacement programs. In essence, the more accurate that infrastructure replacement programs can be in targeting assets nearest to failure, the more near-term effectiveness such programs have. SCE has been working to develop predictive analytics techniques for a wide variety of assets, including transformers, switches, cable, and overhead circuitry. SCE believes that these data science approaches are a very strong complement to infrastructure replacement programs, and that investing in predictive accuracy can improve RSE. This improvement in RSE is most apparent for shorter-term periods of analysis, such as within the 6-year RAMP analysis window.

B. Data Collection & Availability

While SCE had access to good-quality data on the driver side of the bowtie, SCE experienced challenges with data availability on the consequence side of the bowtie. SCE has long-established processes and procedures for understanding driver frequencies. But in developing this RAMP analysis, we spent a good deal of time and effort attempting to understand the present rates of the identified outcomes and consequences in the SCE system.

For example, the bowtie shown in Figure II-1 went through multiple iterations of Outcomes as we developed this RAMP analysis. Specifically, SCE's bowtie initially assumed four outcomes: underground explosions; underground fires; underground "smokers" (i.e., underground release of smoke without overt explosion or fire); and underground "silent failures" (i.e., any underground equipment failure that is not an explosion, fire, or "smoker"). We initially selected this four-outcome framework, in part, because of ongoing work in the industry related to analyzing underground explosions.[27]

However, once this framework was selected, SCE immediately began encountering significant obstacles in modeling outcomes this way. The largest problem was that SCE has not been collecting underground performance data in a manner that can readily inform the distribution of outcomes in the model. Trying to extract the necessary data from Repair Orders was insufficient for modeling purposes. SCE had to rely on an alternate data source for outcome modeling. SCE's subsequent implementation of the CPRR Event Tracker significantly improves data collection practices regarding outcomes of underground equipment failures. Based on the

[27] Specifically, SCE is aware that the Insulated Conductors Committee (ICC) of the IEEE Power and Energy Society (PES) is presently drafting a guide for smoke, fire and explosions in underground electrical structures. Because this guide is currently in draft form, it was not available for direct use in this risk analysis. However, the characterization of outcomes in this draft guide – i.e., smoke, fire and explosion – was a convenient starting point for modeling outcomes in this RAMP analysis.

availability of the CPRR Event Tracker, SCE reduced the number of outcomes from four to two, as discussed earlier in this chapter.

These two outcomes as currently defined still do not encompass some existing underground explosion risk. As the name suggests, the CPRR Event Tracker was developed to add greater clarity to the number of events that could be mitigated by a CPRR Program for vaults and manholes. But other types of subsurface structures can also experience explosion events; these events would not be mitigated by CPRR. Examples of these types of structures include surface operable enclosures (SOEs) and completely submersible transformers (CSTs). The lids of these structures differ from conventional vault and manhole lids. The resulting consequences of explosions within these structures could be substantially different than those within vaults and manholes. These risks have not been included in this RAMP analysis. A third outcome – i.e., explosion in a subsurface structure other than a vault or manhole – should be considered for inclusion in future RAMP scoring efforts in this risk area.

Our analysis here illustrates that RAMP risk modeling should be viewed as an iterative process. Developing a model will generate results, which in turn will help us refine the continued development of the model.

C. Performance Metrics

Two potential metrics would be valuable in evaluating underground equipment failures:

- Quantity of CPUC reportable safety incidents associated with underground equipment.
- Quantity of Underground Equipment Failure Events.

Additionally, SCE proposes to track the effectiveness of executing programs by comparing actual infrastructure replacement counts to planned amounts, including:

- Miles of WCR and CIC replaced.
- Number of oil transformers replaced.
- Number of vault lids retrofitted.
- Number of BURD transformers replaced (if applicable).

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Climate Change

Chapter 12

Rosemead CA
November 15, 2018

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I. Introduction

A. Executive Summary

1. Overview

SCE is committed to building, maintaining, and operating a safe, reliable, clean, and affordable electric system for the communities that we serve. Meeting this commitment requires understanding the impacts of climate change on our electric system and our customers, and adapting to these changes where necessary.

Climate change is a unique risk for SCE. It cannot be summarily addressed as a singular event with a specific outcome. Rather it is a series of evolving near-, medium-, and long-term impacts that will affect assets, business processes, and customers.

The devastating wildfires that swept through parts of California in 2017 and 2018 demonstrate the serious threat that climate change poses to California's communities and to the environment. Adaptation and resilience in the face of climate change are vital. We are working to address the effects of climate change on our infrastructure and in our communities, and to adapt to the uncertainty of climate-related events.

Since 2015, SCE has been involved in national efforts, partnering with the Department of Energy and with other utilities to accelerate deploying adaptation measures (including technologies, practices, and policies) that will create a more resilient energy system and reduce climate- and weather-related vulnerabilities. SCE has completed an initial analysis of its system using future climate projection models to better understand how to prepare for changes in its environment. In 2018, SCE is refining that analysis and preparing plans to deal with near-, medium-, and long-term climate change impacts. This includes severe weather events that are becoming increasingly frequent and intense, as well as long-term issues such as rising sea levels.

SCE looks forward to working with the Commission and its Staff, other utilities, our customers, and key stakeholders to create comprehensive strategies that address the current and future impacts of climate change across critical infrastructure systems.

2. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 – Chapter Scope	
In Scope	How SCE will manage and adapt to the impacts of climate change to our electric system and our customers.
Out of Scope	SCE's actions to reduce greenhouse gas emissions.
Time Periods Evaluated & Methods Used	Due to the unique nature of climate change, this chapter evaluates the climate change risk over *two time periods*, using two separate methods: • **Near-Term Period (2018 – 2023):** In Sections II - VII, SCE performs a risk assessment of climate change over this time period using the same bowtie structure and RAMP risk model used in the other RAMP chapters. SCE calculates risk reduction and risk spend efficiency for various controls and mitigations that will address near-term climate change risks.[1] • **Climate Change Vulnerability and Impact Assessment (2018 to 2050):** In Appendix 1 to this chapter, SCE evaluates the long-term risk posed by climate change, from now through 2050. Here, SCE does not use the bowtie structure or risk model found in other RAMP chapters. Instead, SCE leverages other scientific models and research to analyze climate risks to SCE's assets, business processes, and customers over broader time horizons. This Climate Change Vulnerability and Impact Assessment considers event-based risks (e.g., major storms) as well as more gradual risks (e.g., rising sea levels).

3. Summary Results – Near-Term Period (2018 – 2023)

SCE examined potential consequences from 99th percentile extreme heat events, extreme rain events, and extreme wildfires in the near term (2018-2023). Table I-2 and Figure I-1 summarize the resulting baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.[2] Further detail is provided in Sections II - VII.

[1] The RAMP risk model is largely designed for risk assessment of drivers that are event-based (such as major storms). Thus other longer-term, non- "event-based" climate change impacts (such as rising sea levels) are assessed in Section IX as part of the Climate Change Vulnerability and Impact Assessment.
[2] In this chapter, SCE is focusing on the mean outputs of the model rather than the tail average outputs. The mean outputs are already the result of a 99th percentile-type year. Accordingly, the tail average of 99th percentile events are exceptionally extreme and unlikely.

Table I-2 – Summary Results: Annual Average Over 2018 – 2023 Time Period

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Emergency Management	x	x	x
C2	Fire Management Program	x	x	x
C3	Climate Adaptation Community Grants*	x	x	x
M1	Climate Adaptation & Severe Weather Program	x	x	x
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	x	x	
M2b	Situational Awareness, Monitoring & Analytics (Max)			x
M3	Distribution System Stress Reduction Program		x	
Mean (MARS)	*Cost Forecast ($ Million)*	$14	$18	$20
	Baseline Risk	4.53	4.53	4.53
	Risk Reduction (MRR)	1.06	1.06	1.10
	Remaining Risk	3.47	3.46	3.42
	Risk Spend Efficiency (RSE)	0.08	0.06	0.05
Tail Average (MARS)	*Cost Forecast ($ Million)*	$14	$18	$20
	Baseline Risk (MARS)	14.57	14.57	14.57
	Risk Reduction (MARS)	3.03	3.05	3.23
	Remaining Risk	11.54	11.52	11.33
	Risk Spend Efficiency (RSE)	0.22	0.17	0.16

CM: Compliance (Not shown in this chart, but addressed in Section III; this is an activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this report, and as such, excludes these activities from this table.)

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does model controls in this report.)

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE does model mitigations in this report.)

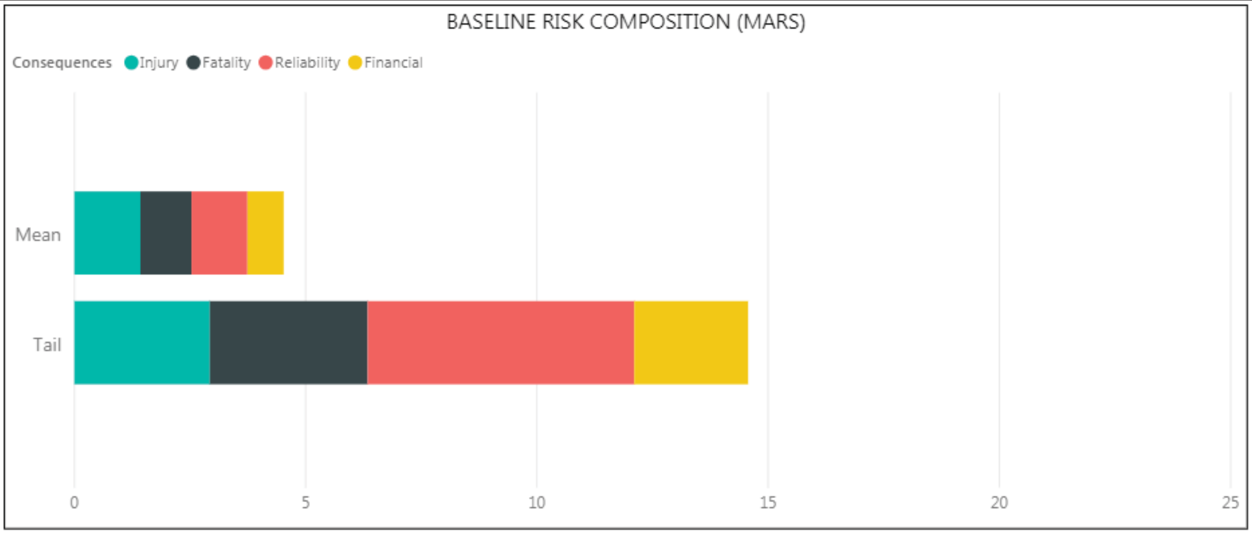
MARS: Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk consequences from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR: Mitigation Risk Reduction. This is the reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE: Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

**C3 is not modeled or included in the costs for this table.*

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

MARS CONSEQUENCE

AggregationType	Injury	Fatality	Reliability	Financial	**Total**
Mean	1.43	1.10	1.21	0.78	**4.53**
Tail	2.93	3.41	5.77	2.46	**14.57**

The risk evaluation results shown above reflect our near-term risk analysis, which contemplates the annual impacts from identified risk outcomes. On a mean basis, the model contemplates the annual impacts from ten triggering events, including:

- Six instances of major storm events;
- Less than one instance of a catastrophic storm;
- Approximately three instances of increased energy procurement costs due to heat events; and
- Less than one instance of exceptionally high energy procurement costs due to heat events and other compounding factors.

On an annualized, unmitigated basis, the baseline translates to less than two serious injuries per year (1.63); less than one fatality per year (0.20); approximately 97 million Customer Minutes Interrupted; and approximately $157 million in financial consequences.

In comparison, the Proposed Plan is forecast to reduce consequences to approximately one serious injury per year; less than one fatality per year (0.13); approximately 69 million Customer Minutes Interrupted; and approximately $112 million in financial consequences.

4. Summary Results – Climate Change Vulnerability and Impact Assessment (2018 - 2050)

SCE is in the process of completing a comprehensive near-, medium-, and long-term Climate Change Vulnerability and Impact Assessment for the 2018-2050 time period. This assessment will identify and evaluate a comprehensive suite of climate change drivers, including both event-based and more gradual impacts of climate change. This includes analyzing near-term climate impacts resulting from rising sea levels, drought, snowpack, etc., as well as the compounding and cascading impacts that arise from climate change hazards.[3]

Because we do not yet have final results, SCE plans to update its proposed climate change mitigation plan in SCE's Test Year 2021 General Rate Case (GRC) submission.[4] Please see Appendix 1 to this chapter for additional information on this assessment.

B. Climate Change Terminology

In California and across the nation, there are many research efforts, policy discussions, and regulatory proceedings evaluating climate change. It is helpful to understand and match up the terminology that is used across forums. Accordingly, SCE includes guidance here on how we are using terms within this RAMP chapter, relative to these other forums.

SCE defines climate adaptation in the context of climate risks. Climate adaptation means adjusting utility systems and business practices to deal with the current and likely consequences of climate change. Individual climate adaptation actions are also called "controls" or "mitigations" in the context of this RAMP report in order to use language consistent with other RAMP chapters. This terminology is not to be confused with the other common use of the term "mitigation" in the climate change policy arena, which can refer to actions specifically targeted at actually reducing greenhouse gas emissions.

SCE undertakes adaptation efforts in response to projected climate change impacts that are expressed over time in the near-, medium- and long-term. Adaptation strategies and tactics can range from *incremental* (relatively low-investment change to existing processes to be more resilient in the face of climate change) to *transformative* (changes requiring significant investment of time and resources to implement). The range depends on the timing of potential climate change impacts as well as whether potential impacts are extreme, gradual, or cascading and compounding.

[3] Cascading and compounding impacts include hazards that can potentially exacerbate one another, possibly causing greater stress or damage to the electric system.
[4] SCE is scheduled to file its 2021 GRC Application in September, 2019.

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C. Climate change increasingly impacts Californians, in the RAMP period (2018-2023) and beyond.

Climate change is already affecting Californians, who now face a "new normal." According to California Natural Resources Agency, the impacts of climate change are evidenced today by the increase in frequency and/or severity of extreme events (e.g., wildfires, heavy rains, and heatwaves), as well as more gradual changes measured over the course of a year, a decade, or longer (e.g., drought, changes in snowpack, sea level rise, and increasing average temperatures). The impacts are also seen in cascading or compounding conditions caused by multiple potential hazards (e.g., rising temperatures result in more frequent drought conditions, which collectively can fuel greater bark beetle infestations, leading to greater tree mortality).[5] Independent state, federal, and non-governmental groups have identified several climate threats[6] that will impact California and pose risks to SCE.

Table I-3 and Figure I-2 describe SCE's two-tiered approach to assessing climate risk in the near- and longer-term. Table I-3 includes a summary of the climate drivers evaluated, the potential impacts (or outcomes) of these drivers, and adaptation actions (or mitigations) we are considering to reduce climate risk. Figure I-2 depicts a comprehensive bowtie describing SCE's overall approach, including drivers and outcomes assessed in the RAMP and Climate Vulnerability and Impact Assessments. This approach builds on the 2016 *Southern California Edison Climate Impact Analysis and Resilience Planning* report. [7]

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[5] *See* California Natural Resources Agency. 2018. *Safeguarding California Plan: 2018 Update, California's Climate Adaptation Strategy, January 2018*, a*vailable at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf, pp. 8, 148 and 244.

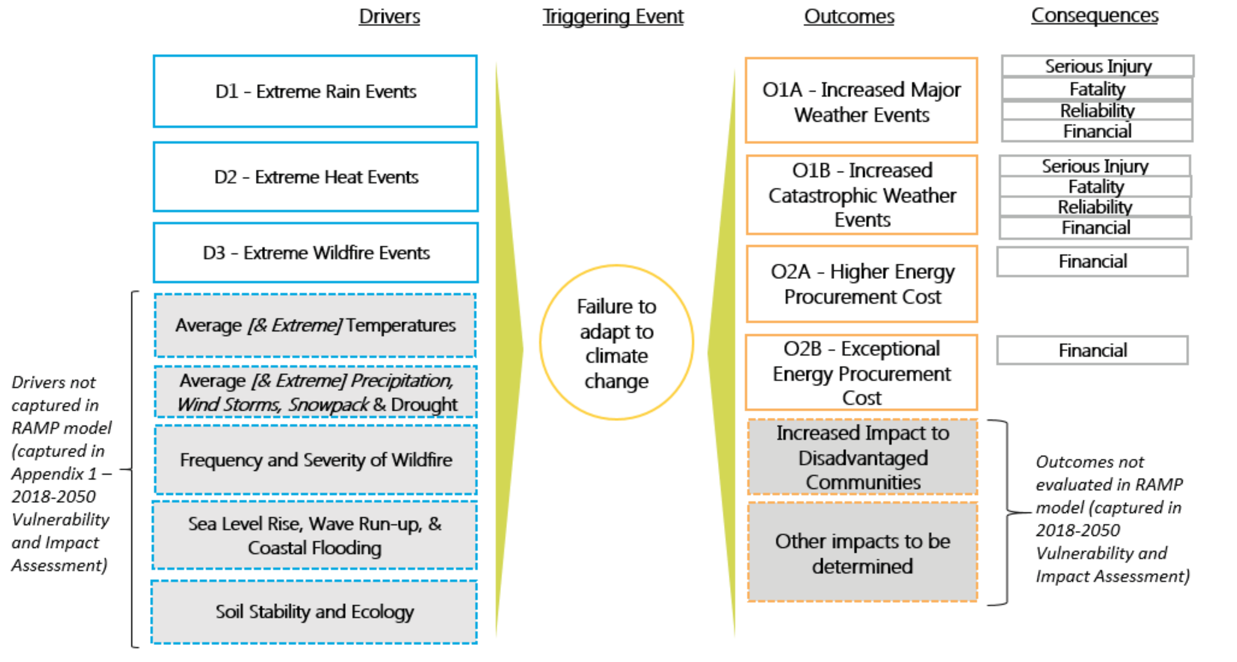
[6] A number of sources, including DOE literature, cite the specific hazards we can anticipate in California. One example is found in the DOE Climate Change and the Electric Sector: Regional Vulnerabilities and Resilience Solutions. This source identifies and evaluates key climate impacts and vulnerabilities by region of the US. California impacts are discussed on pages 3-1 to 3-14, *available at* https://www.energy.gov/sites/prod/files/2015/10/f27/Regional_Climate_Vulnerabilities_and_Resilience_Solutions_0.pdf

[7] Please refer to WP Ch. 12, pp. 12.1 – 12.32 *(2016 SCE Climate Impact Analysis and Resilience Planning Report)*.

Table I-3 – Comparison of Near-Term & Medium- and Long-Term Climate Risk Analyses

	Near-Term RAMP Analysis (2018 – 2023)	Climate Change Vulnerability and Impact Assessment (2018- 2050)
Climate and Environmental Drivers Evaluated	• Extreme Heat Events • Extreme Rain Events • Extreme Wildfire Events	• Average & Extreme Temperatures • Average & Extreme Precipitation, Wind, Storms & Snowpack; Severity of Drought • Frequency and Severity of Wildfire • Sea Level Rise, Wave Run-up, & Coastal Flooding • Soil Stability & Ecology (Landslides, Mudslides, and Subsidence, Vegetation, and other Ecological Variables)
Outcomes Evaluated	• Increased Major Storm Events • Increased Catastrophic Storm Events • Higher Energy Procurement Cost • Exceptional Energy Procurement Cost	• Everything in RAMP analysis, plus: • Increased impact to disadvantaged communities • Other impacts to be determined
Mitigations Considered	• Emergency Management • Fire Management • Climate Adaptation Community Grants • Climate Adaptation & Severe Weather Program • Situational Awareness, Enhanced Forecasting & Analytics • Equipment Replacement due to System Stress	• Everything in RAMP analysis, plus: • System hardening • Relocation of assets • Exploration of technology solutions • Changes to business processes, planning, and practices

Figure I-2 – Overall Climate Change Bowtie (2018 – 2050)[8]



To SCE's knowledge, current science as it relates to wind projections is still fairly uncertain, especially in the ability to project changes in extreme (i.e., 99th percentile) wind events. However, wind events that happen concurrently with wildfire or major storm events can cause cascading or compounding impacts (e.g., making the extreme event even worse). Therefore, non-climate environmental drivers (such as wind events) are important factors that SCE must consider to the extent possible. These drivers are included in this longer-term analysis.

Additionally, SCE is examining the potentially disproportionate impact of climate drivers on the vulnerable and disadvantaged communities SCE serves, using existing vulnerability indices such as CalEnviroScreen and the California Healthy Places Index to inform our efforts.

To foster climate resilience on the part of SCE and the communities we serve, the Company is evaluating options over the near-, medium-, and long-term. For example, SCE is exploring ways to:

- Improve infrastructure and systems to enhance resilience (e.g., hardening system components to withstand extreme events; adding more infrastructure to offset system stress as a result of increasing heat; aligning engineering criteria; and adjusting replacement specifications with climate projections);

[8] The drivers which are not event-based were not modeled in the near-term RAMP risk analysis; they are included in grey boxes and will be explored in Appendix 1 through the Climate Change Vulnerability and Impact Assessment.

- Change utility operating practices to mitigate climate change impacts (e.g., changing vegetation management practices, increasing weather and hazard monitoring; increasing predictive modeling capabilities; developing consistent asset planning and load forecasting criteria based on future scenarios using climate models; and planning with customers to address impending hazards like sea level rise and coastal inundation); and
- Increase our outreach to engage communities about climate change impacts and collaborate on ways to mitigate those impacts (e.g., improving grid resiliency in climate vulnerable communities; developing funding opportunities for communities to conduct vulnerability assessments and mitigation strategies; and developing targeted engagement with local governments regarding key hazards that may impact communities and utilities).

D. SCE has formed a Climate Adaptation and Severe Weather Program to facilitate a consistent assessment and mitigation approach across the Company

Much of the efforts we describe in this RAMP chapter will be coordinated by SCE's new Climate Adaptation and Severe Weather Program. The program aims to identify the appropriate framework and criteria to assess and mitigate climate risks, and coordinate the use of this framework on a company-wide basis. SCE describes these efforts in Section IV under the Climate Adaptation & Severe Weather Program mitigation (M1).

SCE's Climate Adaptation and Severe Weather Program builds on our significant climate resilience work to date. It advances the analysis and activities described in the 2016 *Southern California Edison Climate Impact Analysis and Resilience Planning* report, identifying key climate drivers and vulnerabilities impacting SCE over the next 100 years, and proposing mitigation measures to increase climate resilience in the near-, medium-, and long-term.

E. Strong collaboration among public and private stakeholders is necessary to fully understand the near- and long-term effects of climate change.

For SCE to successfully adapt to climate change, we must partner closely with a broad coalition of stakeholders across all sectors – government, private, non-profit, academic, and community-based organizations – to align our goals and resources related to climate change adaptation. *The Company cannot operate independently in preparing for the impacts of global climate change.* The interdependencies that exist between the utility industry, emergency management, and local communities require that any broadly-implemented resilience strategy include each entity.

One example of this type of collaboration occurred in 2015, when SCE became one of 17 utilities to voluntarily join the Partnership for Energy Sector Climate Resilience, a U.S

Department of Energy (DOE) Initiative. The partnership aims to enhance energy security by improving the resilience of energy infrastructure against the impacts of extreme weather and climate change.

SCE is also actively participating in the Commission's Order Instituting Rulemaking (OIR) to Consider Strategies and Guidance for Climate Change Adaptation (R.18-04-019). SCE fully supports the OIR's vision to: (1) understand and assess climate change's potential impact on investor-owned electric and gas utilities' ("IOU") infrastructure; and (2) incorporate appropriate climate adaptation strategies into Commission proceedings and activities, as well as the IOUs' respective planning, operations, and procurement activities.

II. Risk Assessment

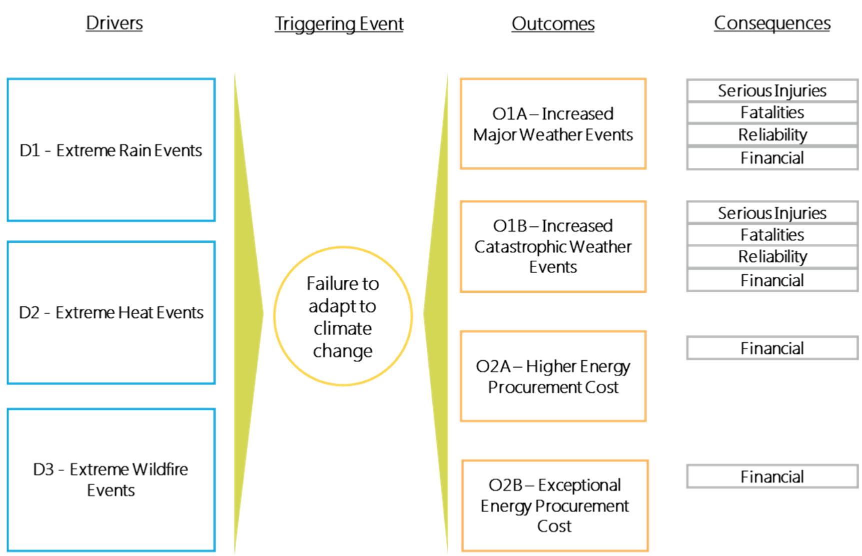
A. Background

Sections II - VII will detail the RAMP model risk assessment that SCE performed on near-term climate change risks from 2018-2023.

B. Risk Bowtie Analysis

Figure II-1 shows the risk bowtie used to structure the near-term Climate Change risk assessment.

Figure II-1 – 2018-2023 Risk Bowtie



C. Driver Analysis

The drivers in this chapter were identified from established climate science literature and common themes in climate models.[9]

In the RAMP risk model, SCE chose to use "99th percentile" data for each of the three event-based climate drivers. This reflects expected shifting extremes due to climate change in the near-term. These three climate drivers are projected to change compared to historic averages as the climate changes (i.e., more frequent and hotter heatwaves, a downward trend in frequency of extreme rain events, and more extreme wildfires).

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[9] See, e.g., Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja, Statewide Summary Report, *California's Fourth Climate Change Assessment (2018),* publication number: SUMCCCA4-2018-013, *available at* http://www.climateassessment.ca.gov/state/docs/20180827-StatewideSummary.pdf.

These 99th percentile events were calculated based on a combination of historical data within SCE's service area and a range of potential future values, using a mix of SCE temperature and precipitation data as well as CAL FIRE data. We used a statistical modeling method to forecast expected increases (for extreme heat events and extreme wildfires) and decreases (for extreme rain events) associated with a changing climate for the 2018-2023 time period. This analysis is described for each driver in the following sections.

Since the drivers used are representative of 99th percentile events, they can be interpreted as the worst-case weather scenario SCE may face between now and 2023 due to a changing climate.

Figure II-2 – 2018 Projected Driver Frequency Summary

1. D1 - Extreme Rain Events

To capture rare and extreme rain events, SCE used data from 75 weather stations across the Los Angeles/Orange County area. This data was utilized to calculate a 99th percentile rain event.[10] Using this data, we determined that the 99th percentile rainfall event is a cumulative 1.5 inches of rain over 3 consecutive days or less. During such events, the electric system can experience significant strain in the form of outages and storm declarations.[11]

While climate models are suitable for developing forecasts for time horizons beyond 10 years from present, modeling within the 10-year window is limited.[12] Developing projections over near-term timescales (less than 10 years from present) is challenging, due to

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[10] Refer to WP Ch. 12, Index of Workpapers *(D1 – Extreme Rain Events)*.
[11] Refer to WP Ch. 12, p. 12.33 *(Sample of Rain Events and Storm Declarations)*.
[12] Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (Eds.). 2013. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, *available at* http://www.ipcc.ch/report/ar5/wg1/

natural climate variability, including the climate system's inherent randomness.[13,14,15] SCE developed a statistical analysis using historical values to develop projections for mean values in 2018 – 2023. SCE then applied a probability distribution based on the historical distribution of values to better account for uncertainty.

We used data from 2017 back to 1976 to develop a regression and project values for the 2018 - 2023 period. The year 1976 is widely acknowledged as the beginning of a "climate shift," where global temperatures began to increase at least partially due to atmospheric greenhouse gas concentrations.[16]

SCE experienced an average of less than 4 extreme rain events per year from 2014 to 2017. SCE's analysis of data from 75 weather stations indicates a slight downward trend in the number of rain events of this size in the 2018-2023 time period. This near-term variability does not necessarily contradict existing studies that report Southern California may become even wetter due to climate change. Several climate projection models (which span a longer time horizon and consider all rain events) show a potential increasing trend of rain.[17] SCE

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[13] Strategic Environmental Research and Development Program (SERDP) (2016) Climate-Sensitive Decision-Making in the Department of Defense: Synthesis of Ongoing Research and Current Recommendations. US Department of Defense, *available at* https://www.serdp-estcp.org/News-and-Events/Blog/Climate-Sensitive-Decision-Making-in-the-Department-of-Defense-Synthesis-and-Recommendations

[14] Walsh, J; Wuebbles, D; Hayhoe, K; Kossin, J; Kunkel, K; Stephens, G; Thorne, P; Vose, R; Wehner, M; Willis, J; Anderson, D; Kharin, V; Knutson, T; Landerer, F; Lenton, T; Kennedy, J; Somerville, R (2014) Appendix 3: Climate Science Supplement. Climate Change Impacts in the United States: The Third National Climate Assessment, Melillo, JM; Richmond, TC; Yohe, GW; Eds., U.S. Global Change Research Program, 735-789. doi:10.7930/J0KS6PHH, *available at* http://s3.amazonaws.com/nca2014/low/NCA3_Climate_Change_Impacts_in_the_United%20States_LowRes.pdf?download=1

[15] Flato, G; Marotzke, J; Abiodun, B; Braconnot, P; Chou, SC; Collins, W; Cox, P; Driouech, F; Emori, S; Eyring, V; Forest, C; Gleckler, P; Guilyardi, E; Jakob, C; Kattsov, V; Reason, C; Rummukainen, M (2013) Evaluation of Climate Models. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, *available at* http://www.climatechange2013.org/report/full-report/

[16] Trenberth, K.E., P.D. Jones, P. Ambenje, R. Bojariu, D. Easterling, A. Klein Tank, D. Parker, F. Rahimzadeh, J.A. Renwick, M. Rusticucci, B. Soden and P. Zhai, 2007: Observations: Surface and Atmospheric Climate Change. In: *Climate Change 2007: The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, page 240, *available at* https://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter3.pdf

[17] Allen, R, & Luptowitz, R. *El Niño-like teleconnection increases California precipitation in response to warming,* Nature Communications 8, published July 7, 2017, *available at* https://www.nature.com/articles/ncomms16055

analyzed only the projected extreme rain events for the 2018 – 2023 period, using a Poisson distribution[18] to represent the distribution's high tail values.

2. D2 – Extreme Heat Events

SCE calculated extreme heat events using effective temperature, which is a weighted average of three consecutive days of heat. Three consecutive days of high heat are commonly represented as a heatwave, which is when we typically see marked increased load and burden on the electric system. Using effective temperature, we analyzed historical trends across several decades. We used recorded daily maximum temperatures from five weather stations located across Southern California to calculate effective temperature across the service territory. SCE identified 101°F as the 99th percentile value for effective temperature, based on averages of effective temperature data from January 2011 – August 2018. We then used data from 2017 back to 1976 to develop a regression, and project values for the 2018 - 2023 period.[19]

SCE expects to be averaging approximately four extreme heat events per year during the 2018-2023 time period. In contrast, between 1976 and 2017, SCE averaged three events per year. Also, most historical Southern California heat waves have occurred from July to September; but as climate warming occurs, these events appear to begin earlier in the season and continue through the fall, while summer events become more frequent and more intense. The increasing tendency for multiple hot days in succession – resulting in heat waves that last longer – could cause problems for transmission and distribution infrastructure. An especially important factor may be the lack of nighttime cooling that has characterized recent heat waves in California. This absence of nighttime cooling can cause additional stress on the transformers and other electrical components that require regular cooling.

3. D3 – Extreme Wildfire Events

For this RAMP analysis, SCE defines Extreme Wildfire Events as the 99th percentile largest wildfire events, based on acres burned.[20] While this analysis evaluated the entirety of SCE's service area, much of our electrical transmission and distribution lines and equipment are

[18] A Poisson distribution is used to model the number of events occurring within a given time interval. In statistical analysis, it is a distribution function that is useful for characterizing events with very low probabilities of occurrence within some definite time or space.
[19] Please refer to WP Ch. 12, Index of Workpapers *(D2 – Extreme Heat Events)*.
[20] Please refer to WP Ch. 12, Index of Workpapers *(D3 – Extreme Wildfire Events)*.

located in high fire risk areas[21] (approximately 35% of SCE's service area is located in high fire risk areas).

Wildfire activity has increased in recent decades.[22] Since 1979, while the number of fires in California decreased, the acreage burned per year increased. Similarly, the average acres burned per fire has increased over the same time period.[23]

While the size and impact of California's wildfires has grown, recently our state has experienced a dramatic increase in year-round, devastating wildfires unlike anything previously seen. In 2017, Southern California experienced "unremitting" Santa Ana winds accompanied by extremely low humidity (as low as one percent) with low single-digit readings even at the beaches; this resulted in "near apocalyptic" fires.[24] Six of the state's 20 most destructive fires have occurred within the last year.[25]

Unfortunately, 2018 has been another devastating year, with low precipitation, returning drought conditions, and record-setting heat occurring as early as July 2018.[26] This year, the state has seen the largest fire in its history with respect to acreage burned, the

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[21] The term "High Fire Risk Areas" refers to the locations in SCE's service territory that have been given a Tier 2 or Tier 3 designation in the most recent CPUC High Fire Threat District maps (CPUC Fire Maps). See D.17-12-024. The term also encompasses any additional locations that SCE had previously identified in its service area as high fire risk areas prior to the release of the most recent CPUC Fire Maps.

[22] *See* National Oceanic and Atmospheric Administration, *Assessing Fire Hazard Risk In Southern California(2018)*, *available a*t https://coast.noaa.gov/digitalcoast/stories/californiafire.html; *see also,* John Abatzoglou &A. Park Williams, *Impact of Anthropogenic Climate Change on Wildfire Across Western US Forests,* PNAS, (October 18, 2016),*available at* http://www.pnas.org/content/113/42/11770.

[23] CAL FIRE Redbooks, 2016 Wildfire Activity Statistics, *available at* http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF.

[24] Rong-Gong Lin II, *L.A.'s increasingly hot and dry autumns result in "these near-apocalyptic fires,"* L.A. Times (December 21, 2017), *available at* http://www.latimes.com/local/lanow/la-me-ln-weather-thomas-fire-20171221-story.html.

[25] CAL FIRE statistics as of August 20, 2018. Does not include Mendocino Complex fire, which is currently the largest in California's history (acres burned) but not within the top 20 most destructive (structures destroyed). Structures include homes, outbuildings (barns, garages, sheds, etc.) and commercial properties destroyed.

[26] National Interagency Fire Center, *Southern and Central California Monthly/Seasonal Outlook* (Aug. 2018), *available at* https://gacc.nifc.gov/oscc/predictive/outlooks/myfiles/assessment.pdf. (Note that this website is updated daily, and the numbers may have increased since August 2018)

Mendocino Complex Fire.[27] As of August 9, 2018, California's wildfires have burned over 1,121,916 acres,[28] damaged or destroyed over 2,500 structures,[29] and resulted in six fatalities.[30]

Experts had predicted that decades from now climate change would increase the risk of these uncharacteristically large and severe wildfires, including a potential increase in the total area burned.[31] However, it appears that these projected impacts are happening now, and regrettably ahead of some forecasts. Shortly after the Mendocino Complex Fire, Governor Brown explained that "[t]he more serious predictions of warming and fires to occur later in the century, 2040 or 2050, they're now occurring in real time."[32] California's recently released Fourth Climate Change Assessment—while acknowledging that projecting future wildfires is complicated—nonetheless notes the potential for greater fire risk in the future and particularly "mass fires" burning large areas simultaneously.[33]

Given that there are tens of thousands of wildfires in California per year, SCE elected to consider only large California wildfires (those that exceed 300 acres, a threshold established by CAL FIRE).[34] SCE identified 100,124 acres as the present day 99th percentile wildfire size, based on data from 2011 – 2017. We then used data from 1979 – 2017 to develop a regression, and project values for the 2018 - 2023 period.[35,36]

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[27] Eric Levenson, *A look at California's largest wildfires by the numbers,* CNN (August 7, 2018), *available at* https://www.cnn.com/2018/08/07/us/california-fire-numbers/index.html.

[28] National Interagency Fire Center ("NIFC"), *National Year-to-Date Report on Fires and Acres Burned by State and Agency* (August 29, 2018), *available at* https://gacc.nifc.gov/sacc/predictive/intelligence/NationalYTDbyStateandAgency.pdf (Note that this website is updated daily, and the numbers may have increased since August 29, 2018)

[29] NIFC, *National Large Incident Year-to-Date Report* (August 29, 2018), *available at* https://gacc.nifc.gov/sacc/predictive/intelligence/NationalLargeIncidentYTDReport.pdf (Note that this website is updated daily, and the numbers may have increased since August 29, 2018)

[30] Sarah Ravani and Lauren Hernandez, *California Wildfires: Firefighter's death the 6th of 2018; Yosemite Reopens*, S.F. CHRONICLE (August 14, 2018), *available at* https://www.sfchronicle.com/california-wildfires/article/Mendocino-Complex-fires-claim-first-life-5-000-13154845.php#photo-15986939

[31] Tania Schoennagel et al., *Adapt to More Wildfire in Western North American Forests as Climate Changes*, (May 2, 2017), *available at* http://www.pnas.org/content/pnas/114/18/4582.full.pdf.

[32] Jaclyn Cosgrove et al., *California fires rage, and Gov. Jerry Brown offers grim view of fiery future,* L.A. Times (Aug. 01, 2018), *available at* http://www.latimes.com/local/lanow/la-me-ln-california-fires-20180801-story.html.

[33] Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja. (2018). Statewide Summary Report. *California's Fourth Climate Change Assessment.* Publication number: SUMCCCA4-2018-013, *available at* http://www.climateassessment.ca.gov/state/docs/20180827-StatewideSummary.pdf.

[34] CAL FIRE. 2016. Historical Wildfire Activity Statistics, *available at* http://calfire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF.

[35] CAL FIRE. 2018. Historical Wildfire Activity Statistics (Redbooks), *available at* http://calfire.ca.gov/fire_protection/fire_protection_fire_info_redbooks.

[36] While SCE originally intended to use data back to 1976, CAL FIRE only provides data on individual large fires back to 1979.

D. Triggering Event

The triggering event, “failure to adapt to climate change,” reflects the notion that SCE must adapt and thoughtfully decide when identifying mitigations specifically designed to deal with the diverse impacts that climate change will create for our business. Figure II-3 shows the forecast triggering event frequency composition for each year over the 2018 – 2023 period.

As described in the Driver Analysis section, there is a great deal of variability and uncertainty in expected climate change impacts, especially in the near term. Therefore, the number of triggering events should be taken as directional rather than as a specific expected outcome. The slight decrease in projected triggering events occurs because the growth in projected frequency of extreme heat events and extreme wildfire events is offset by the larger projected decrease in frequency of extreme rain events.

Figure II-3 – Triggering Event Frequency Composition

Risk	2018	2019	2020	2021	2022	2023	**Total**
CMC							
Baseline	**10.72**	**10.58**	**10.44**	**10.29**	**10.15**	**10.01**	**62.19**
Driver							
D1 - Extreme Rain Events	5.31	5.14	4.98	4.81	4.65	4.48	**29.37**
D2 - Extreme Heat Events	4.20	4.22	4.24	4.26	4.28	4.30	**25.50**
D3 - Extreme Wildfire Events	1.21	1.21	1.22	1.22	1.23	1.23	**7.32**

E. Outcomes

SCE identified four main outcomes resulting from the triggering event: increased major weather events, increased catastrophic weather events, higher energy procurement cost, and exceptional energy procurement cost. To do this, SCE: (1) evaluated current experience with climate change impacts on our electric system; and (2) conducted historical and statistical analyses of heat, rain, and wildfire data to forecast climate-driven near-term changes and to assess the implications of these changes on SCE’s electric system. Figure II-4 depicts the estimated likelihood of four outcomes that were modeled.

Figure II-4 – 2018 Outcome Likelihood

Outcome Percentage

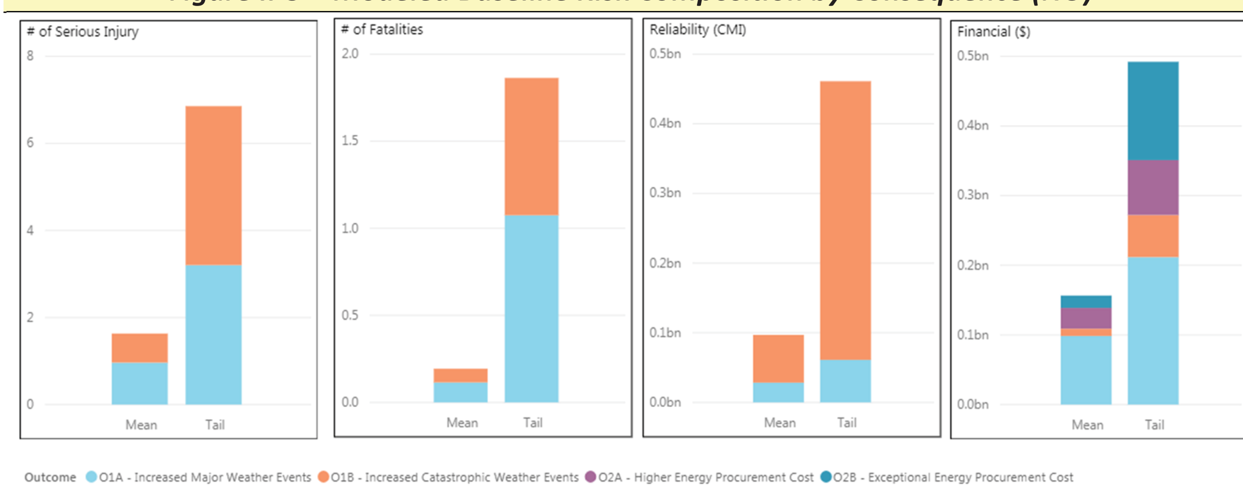
Name	%	Percent
O1A - Increased Major Weather Events	60.0 %	
O1B - Increased Catastrophic Weather Events	5.0 %	
O2A - Higher Energy Procurement Cost	32.5 %	
O2B - Exceptional Energy Procurement Cost	2.5 %	

When ten triggering events per year are applied to these outcome percentages in the model, the following is projected to occur on an annual basis:

- Six instances of major storm events;
- Less than one instance of a catastrophic storm;
- Approximately three instances of increased energy procurement costs due to heat events; and
- Less than one instance of exceptionally high energy procurement costs due to heat events and other compounding factors.

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence. This shows that all of the safety and reliability impacts come from O1A (Increased Major Storm Events) and O1B (Increased Catastrophic Weather Events). These two outcomes also produce the majority of financial consequences associated with this risk. The sections that follow detail the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (NU)



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1. O1A – Increased Major Weather Events

This outcome is defined as facility and infrastructure loss to any of SCE's assets resulting from increasing "major storm events."[37] These events may require major restoration activities, which include remediating damaged transmission and distribution assets, telecommunications equipment, or operational facilities. More frequent or severe extreme rain, heat, or wildfire events could result in more significant outage days, and SCE may need to mobilize and deploy more restoration efforts as a result. SCE has experienced between five to six significant or major storm restoration events per year in the last seven years.

Potential consequences from O1A (Increased Major Weather Events) are summarized on an annualized basis in Table II-1. Safety impacts are associated with injuries or fatalities resulting from storms. Reliability impacts are associated with service interruptions caused by weather events. Financial costs are associated with equipment repair or replacement and restoration activities following weather events. For O1A, the estimate of annual impacts is 0.97 serious injuries, 0.12 fatalities, over 28 million CMI, and over $98 million in financial harm, on a mean basis.

Table II-1 – Outcome 1A (Increased Major Weather Events): Consequence Details[38]

Outcome 1A		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE reviewed worker injuries resulting from storms over 2015 – 2017. Many of these injuries could have easily turned into serious injuries. Based on this, SCE applied an estimate of approximately one serious injury occurring each year during the most extreme storms.	SCE applied a ratio of injuries to fatalities (8.3:1) based on the number of injuries and fatalities accounted for in the National Fire Protection Association's report Fires by Occupancy or Property Type, which uses data from 2010 - 2014.	SCE reviewed representative data on customer minutes of interruption (CMI) from 2014 - 2017 for weather related events (heat days, rain storms, wildfires, etc.). The representative data for identified storms were utilized as baseline inputs to the model. Recorded data shows that SCE experiences between 5-6 major storm events per year.	SCE reviewed data on storm-related expenses (equipment repair and restoration, logistics for procuring new infrastructure, as well as other storm response and recovery activities) from 2014 - 2017. For example the total storm related expenses totalled $65M in 2016 and $97M in 2017. SCE has recorded about 6 major storm events occur per year.
Model Outputs	NU - Mean	0.97	0.12	28,455,249	$ 98,573,300
	NU - Tail Avg	3.21	1.08	61,115,582	$ 211,713,648

[37] A major storm event is defined as significant outage days, where SCE declares a "storm" or restoration event based on damage that may be widespread or extensive enough to require territory-wide coordination. The damage incurred is a result of significantly bad weather such as rain and heat, or weather-driven events like wildfire. SCE also responds to many smaller storm events on a more frequent basis throughout the year.
[38] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.

2. O1B – Increased Catastrophic Weather Events

This outcome is defined as catastrophic facility and infrastructure loss resulting from extreme weather events. This includes similar assets to those described in Outcome 1A. However, Outcome 1B focuses on rare compounding or extreme conditions such as a string of extreme heat or rain events that can lead to catastrophic loss. These types of events may be physically isolated but can cause complex impacts. For example, significant rainfall in some parts of the SCE territory may result in landslides that could potentially threaten transmission lines that serves communities in another part of the service area.

Potential consequences from O1B are summarized on an annualized basis in Table II-2. Safety impacts are associated with injuries or fatalities resulting from storms. Reliability impacts are associated with service interruptions caused by weather events. Financial costs are associated with repairing equipment or replacing and restoring equipment and assets after a weather event has occurred. For O1B, the estimate of annual impacts is 0.67 serious injuries, 0.08 fatalities, over 68.5 million CMI, and over $10.3 million in financial harm, on a mean basis.

Table II-2 – Outcome 1B (Increased Catastrophic Weather Events): Consequence Details[39]

Outcome 1B		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE reviewed the 7 largest wildfires in the past 12 years and observed 1 fatality to a utility worker, or 0.0833 fatalities/event. SCE applied a ratio of (8.3:1) based on the number of injuries and fatalities accounted for in the National Fire Protection Association's report on Fires by Occupancy or Property Type, which uses data from 2010 - 2014, to derive a serious injury value.	SCE reviewed the 7 largest wildfires in the past 12 years and observed 1 fatality to a utility worker. This translates to 0.0833 fatalities/event.	As an example for this outcome, SCE evaluated the impacts from extreme rain events on areas prone to landslides that contain transmission towers. SCE estimated that such extreme rain events to occur every 37.5 years, and could result in 453 million minutes of customer interruption on average.	SCE estimated the cost to restore power and provide backup generation to mitigate the impacts of the outcome. SCE estimated $18-20M dollars for contingency back-up generation.
Model Outputs	NU - Mean	0.67	0.08	68,507,788	$ 10,358,584
	NU - Tail Avg	3.65	0.79	399,964,690	$ 60,475,864

3. O2A – Higher Energy Procurement Cost

This outcome occurs when extreme heat contributes to higher energy procurement costs. Heatwaves are typically three or more consecutive days of extremely high temperatures.

[39] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.

Historically, heatwaves occur between three to four times per year in SCE's service territory and result in peak electricity demand.

Electricity market costs during heatwaves are typically about four times higher than prices of electricity during non-heatwave summer days, although the load is only 1.3 times higher on average for heatwaves vs non-heatwave summer days. As an example, the total cost of electricity during heatwaves in 2017 (four events) was about $67M more as compared to what the costs would have been on average temperature summer days.[40]

The price of electricity is usually highest in the summer months due to customer demand, power plant availability,[41] and cost of fuel.[42] Other factors such as weather conditions and regulations also influence the price of electricity.[43] Additionally, heat increases the cost of operation and maintenance, for power plants and transmission and distributions systems,[44] and also increases line losses of electricity.[45]

Potential consequences from O2A are summarized on an annualized basis in Table II-3. Financial costs are associated with increased energy procurement costs during extreme heat events. For O2A, the estimate of annual impacts is nearly $30 million in financial harm, on a mean basis.

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[40] Please refer to WP Ch. 12, pp. 12.36 – 12.42 *(Heatwave vs. Average Summer Temperatures Workpaper)*.

[41] Costs to operate and maintain power plants vary based on the type, age and efficiency of the power plant.

[42] Fuel costs such as natural gas vary in correlation with demand. A higher demand increases the fuel cost and therefore increases the cost to generate electricity.

[43] Extreme temperatures can increase the demand for electricity, especially for cooling. Therefore, the price of electricity goes up in response to the demand. Significant strain is also placed on generators and transmission lines as they perform less efficiently. In addition, wildfires or the risk of wildfires can force transmission lines to be taken offline, and these situations impair the operation of the system.

[44] Transmission and distribution systems supply electricity and have associated maintenance cost and schedules, including repair and restoration of damaged components resulting from accidents or extreme weather events.

[45] Transformers, power lines and ancillary equipment will function at a lower efficiency due to line loss arising from higher temperature operating conditions. Line loss is energy waste resulting from the transmission of electrical energy across power lines; it can affect transmission and well as distribution lines. These losses occur due to the conversion of electricity to heat and electromagnetic energy. In hotter temperatures, line loss is more prominent.

Table II-3 – Outcome 2A (Higher Energy Procurement Cost): Consequence Details[46]

Outcome 2A		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*				SCE evaluated the differences in daily energy procurement costs during summer heat wave days vs non-heatwave summer days, over the 2015-2017 period.
Model Outputs	NU - Mean				$ 29,912,995
	NU - Tail Avg				$ 78,838,221

4. O2B – Exceptional Energy Procurement Cost

a. Description

As highlighted in Outcome 2A, there is a correlation between heatwaves and higher energy procurement costs. However, when this phenomenon is coupled with other compounding forces, such as volatile natural gas prices, the price of electricity can rise to unprecedented levels. For example, an instance occurred from July 24th – 25th, 2018 when the market reacted unfavorably to declarations by SoCalGas related to natural gas supply (Stage 4 alert on 7/23/18 and Low Inventory Operational Flow Order on 7/25/18).[47] As a result, natural gas prices soared from an average of $4/MMBTU to $39/MMBTU, driving up the market price of electricity by a similar order of magnitude. SCE has experienced one instance of exceptionally high procurement costs due to heat events and other compounding factors in 2018.[48] The cost to procure power during these events was approximately $200M higher than what otherwise would have been incurred given average summer temperatures and absent compounding impacts from other market forces.[49]

Potential consequences from O2B are summarized on an annualized basis in Table II-4. Financial costs are associated with energy procurement costs during extreme heat events coupled with other compounding forces, such as volatile natural gas prices. For O2B, the estimate of annual impacts is over $17 million in financial harm, on a mean basis.

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[46] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.
[47] US Energy Information Administration – Published September 25, 2018, *available at* https://www.eia.gov/todayinenergy/detail.php?id=37112
[48] Year-to-date through 9/13/18.
[49] Please refer to WP Ch. 12, pp. 12.36 – 12.42 *(Heatwave vs. Average Summer Temperatures Workpaper)*.

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Table II-4 – Outcome 2B (Exceptional Energy Procurement Cost): Consequence Details[50]

Outcome 2B		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				SCE evaluated the differences in daily energy procurement costs during summer heat wave days vs non-heatwave summer days in 2018, when those days experienced compounding market forces that drove energy prices exceptionally higher than normal.
Model Outputs	NU - Mean				$ 17,675,855
	NU - Tail Avg				$ 141,132,954

[50] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*. Also note that while O2B is focused on exceptionally high procurement costs compared to procurement costs contemplated in O2A, the modeled financial consequences for O2B, as shown in Table II-4, are lower on an annual basis than O2A. This is due to the lower likelihood of occurrence of O2B. For example, in the last four years, O2B has only occurred once while O2A has occurred 12 times, and this ratio is reflected in the model outputs.

III. Compliance & Controls

SCE has programs and processes in place that address climate change impacts on SCE's business. These controls are summarized in Table III-1 and described in more detail below.

Table III-1 – Inventory of Compliance & Controls[51]

Controls		Risk Bowtie Impacts			2017 Recorded Capital ($M)	2017 Recorded Expense ($M)
ID	**Name**	**Drivers**	**Outcomes**	**Consequences**		
C1	Emergency Management	n/a	O1A, O1B	All	$0	$3.7
C2	Fire Management Program	n/a	O1A	All	$0	$0.5
C3	Climate Adaptation Community Grants (not modelled)	n/a	n/a	n/a	$0	$0.5

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does risk-model controls in this report.)

A. C1 – Emergency Management

Emergency Management provides expertise and direct support for SCE's emergency management preparedness, response and recovery operations. The group's personnel build relationships with external emergency response partners, such as law enforcement, first responders, other utilities and city, county, state, and federal government agencies to enhance resiliency of SCE's operations and external collaboration during actual incidents. Emergency management includes training, exercising and activating one or more SCE Incident Management Teams (IMT)[52] / Incident Support Teams (IST),[53] and the Crisis Management Council (CMC).[54]

SCE coordinates drills and exercises for the IST/IMT and CMC in addition to an annual Full-Scale Exercise. That exercise includes external evaluators and emergency management counterparts from other utilities and government agencies.

SCE operates a 24/7 Watch Office that serves as a hub for Emergency Management. The Watch Office is the primary point of contact for SCE's various control centers (e.g., grid control, distribution operations control, telecommunications control, security operations, and more). It provides company-wide situational awareness (in collaboration with the co-located Situational

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[51] Please refer to WP Ch. 12, pp. 12.43 – 12.52 *(RAMP Mitigation Reductions)*.

[52] An IMT is a team of trained personnel from across SCE who are brought together to coordinate within and across four functional areas of the Company (Electrical Services, Generation, Security & Facilities, and Information Technology) prior to and during an emergency event.

[53] An IST is a team of trained personnel similar to an IMT; however, the IST acts as a coordinating body to provide governance when there are multiple simultaneous incidents ongoing, such as multiple wildfires in different geographical regions of our service territory

[54] The CMC is a senior executive governance body responsible for providing strategic corporate-level policy making and direction related to emergency management. The CMC does not make incident-level or tactical decisions.

Awareness Center), reports on critical incidents, executes notifications, and manages IST/IMT activations.

SCE utilizes an Emergency Operations Center (EOC) to assemble IST/IMTs and help them collaborate when coordinating a corporate response to an incident. The EOC has modernized IT/Telecommunication equipment, and is co-located with the Watch Office and Situational Awareness Center to enable effective planning, communication and engagement with all stakeholders including field crews and external parties to efficiently coordinate restoration and recovery operations.

While the costs for this control are only represented within this Climate Change chapter, the Emergency Management control also supports our preparedness and response to other risks, including those presented in other RAMP risk chapters.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Emergency management practices reduce the safety and reliability consequences of Outcomes 1A and 1B. Keeping our customers and our crews safe is our highest priority during major or catastrophic storm events. IMTs, field crews, and operators set objectives for safety, restoration, and other priorities before commencing work. Job hazard assessments are conducted and safety instructions are sent to the various teams and crews mobilized to restore service. Collectively, these actions refocus our work and our employees on safety and reduce safety-related consequences.

The coordinated approach to emergency management can reduce reliability consequences by utilizing emergency management plans developed in advance of the severe weather events (rain storms, heat storms, and wildfires) to maintain reliable performance of the system, including in situations where natural hazards can cause infrastructure damage. SCE response crews are often staged and ready to respond and restore equipment and service during storms and other incidents.

In addition, SCE proactively addresses emergent risks that may occur because of extreme weather-related events. For example, in 2015, the El Niño season threatened to cause major outages in Santa Barbara County if non-redundant infrastructure serving that geographic area were to experience significant weather-related damage. In response to this risk, SCE took proactive steps and provided for alternative generation in the event that power delivery equipment experienced significant damage due to extreme rainfall and deep-seated landslides.

Financial consequences can be reduced or substantially avoided by effectively planning and executing mitigation strategies to moderate the impact of damage to SCE infrastructure. This in turn reduces “downstream” impacts to customers such as loss of service, productivity and revenue. For example, SCE coordinates with fire agencies to deploy tactics such as dropping flame retardants and cutting dozer lines to limit the spread of wildfires to critical infrastructure.

B. C2 – Fire Management Program

SCE maintains a Fire Management Team that includes fire management officers possessing experience as fire fighters and/or linemen. These fire management officers perform the following activities:

- Conduct training on electrical safety for first responders;
- Proactively monitor fire threats to SCE infrastructure, coordinate with SCE IMTs, and assist in restoration activities involving electrical assets;
- Coordinate planning and response operations with external agencies[55] and first responders;
- Monitor climate change impacts on hazardous fuel (grass, heavy brush, chaparral, etc.) build-up that increase the severity and duration of wildfire events; and
- Support project teams focus on hardening the grid to accommodate climate change drivers linked to wildfires.

Over the past few years, these efforts have become more integral to preparing for and responding to wildfires. Accordingly, SCE plans to hire one additional fire management officer and one fire scientist to support the increased focus on preventing and mitigating fires. These resources will support projects, programs and work streams focused on preparing for, responding to, and mitigating the impacts of wildfires. This includes supporting the development of complex fire models, which are designed to predict wildfire ignition and propagation by considering multiple variables such as weather, fuel, and asset conditions.

[55] External agencies that SCE coordinates with include: United States Forest Service, CAL FIRE, and County Fire Authorities.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

The actions of our Fire Management Programs will help reduce the severity and impact of major and catastrophic wildfires that may impact SCE assets and the communities we serve. These actions include disseminating red flag warnings[56] to prepare for fire weather conditions. Additionally, SCE fire management officers coordinate with state and federal agencies on tactical efforts such as dropping flame retardant and cutting fire breaks, as well as other measures to limit the spread of fires, help ensure safety, and protect critical transmission and distribution lines.

By identifying fires and monitoring fire behavior, SCE coordinates with agency representatives to limit and contain the spread of encroaching fires. By adding a fire scientist, SCE will be able to develop and mature its fire modeling capabilities.

Safety consequences can be reduced as a result of SCE conducting training sessions on electrical safety for first responders, issuing fire threat indications for SCE assets, and helping facility evacuations as necessary. Furthermore, Fire Management can assist in coordinating firefighting activities during an event to avoid contact with energized equipment and sidestep other potentially dangerous situations. Fire Management educates SCE personnel on tactics that the fire agencies use, so that efforts with the fire agencies are aligned and coordinated.

C. C3 – Climate Adaptation & Resiliency Community Grants

This control funds a diverse set of public and private stakeholders to support projects and programs that help disadvantaged communities adapt to climate change. The funding model focuses on collaborating and facilitating regional climate adaptation and resiliency.

Funded programs and projects include research, community-based education, environmental justice outreach, habitat restoration, disaster preparedness, species protection and environmental stewardship. SCE partners with local and regional government associations and efforts, such as the Los Angeles Regional Collaborative for Climate Action and Sustainability

[56] A red flag warning is prescribed by the National Weather Service based on critical fire weather conditions either occurring now, or will shortly. A combination of strong winds, low relative humidity, dry fuels and the possibility of dry lightning strikes can contribute to extreme fire behavior. Accessed September 26, 2013, http://www.fire.ca.gov/communications/communications_firesafety_redflagwarning

(LARC), so that alignment exists and effective and widespread implementation occurs. Because these grants are issued using shareholder funds, SCE does not model the effect of this control.

D. Additional Controls Discussed in Other Chapters

The Wildfire RAMP chapter contains one compliance control (CM1 – Vegetation Management) and one control (C2 – Ester Fluid (FR3) Overhead Distribution Transformer), which also provide benefits in the Climate Change arena. The quantitative modeling of the costs and benefits of these controls is provided in the Wildfire chapter. SCE qualitatively addresses how controls modeled in the Wildfire chapter likely provide benefits for climate change adaptation in this chapter. This qualitative approach was chosen because:

- It allows SCE to examine how Wildfire chapter controls and mitigations not only impact the 99th percentile extreme wildfires modeled in the Climate Change chapter, but also to look at potential benefits for the ongoing longer-term Climate Change Vulnerability Assessment (see Appendix 1). That longer-term assessment will examine wildfires associated with climate change and examine the impacts of increasing temperatures and heatwaves. This assessment may ultimately provide additional detail concerning mitigations that affect broader wildfire risks not associated with utilities.
- The magnitude of dollars that would be included if the Wildfire chapter controls and mitigation were quantitatively modeled would dwarf the existing portfolio of controls and mitigations contained in this chapter. For example, the costs associated with the controls and mitigations included in the climate change portfolio are approximately $13 million per year, while the wildfire mitigations total well over $100 million per year. Including the Wildfire chapter controls and mitigations could skew the existing portfolio results and potentially dilute the control/mitigation analysis currently included in the Climate Change chapter.
- The qualitative assessment approach can provide the base for potential further improvement and cross-chapter integration in future RAMP filings.

Table III-2 contains a summary of the controls included in the Wildfire chapter that could provide benefits for reducing climate change risk.

Table III-2 – Controls Included in Wildfire Chapter with Qualitative Climate Change Benefits

Wildfire Chapter Control	Control Description	Likely Benefits for Climate Change Chapter
CM1 – Vegetation Management	Vegetation management includes the expenses associated with tree pruning and tree removal in proximity to transmission and distribution high voltage lines, and weed abatement around selected overhead structures. It also includes costs to plant different species of trees as replacements and in handling preventive soil treatment. Besides SCE's normal vegetation management program, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle or resulting from California's Drought Order.	• Tree pruning and removal could decrease risk to SCE's infrastructure from non-utility-associated wildfires (e.g., wildfires caused by lightning strikes, arson, etc.) • Removal of dead, dying and diseased trees will reduce the fuel available to spread wildfires. Removing these trees will also prevent them from catching fire due to causes other than utilities.
C2 – Ester Fluid (FR3) Overhead Distribution Transformer	Distribution line transformers insulated with mineral oil have a flashpoint of approximately 180°C while FR3 insulated transformers have a flashpoint closer to 360°C. This increased flashpoint means that new FR3 filled transformers can absorb more fault energy during an internal fault before failing catastrophically. This reduces the chance of igniting surrounding brush or other flammable material. Additionally, FR3 transformers have increased thermal loading capability which should improve summer heat storm performance, increasing the life expectancy of the transformers' insulation.	• As temperatures rise and the number and severity of extreme heat events increase, transformer capacity, efficiency, and resiliency are expected to decline. FR3 transformers can help mitigate these impacts through improved performance during summer heat storms.

IV. Mitigations

Besides the work that SCE has performed through 2017, SCE has identified methods to mitigate this risk. These activities are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[57, 58]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Prop.	Alt. #1	Alt. #2
M1	Climate Adaptation & Severe Weather Program		O1A, O1B	All	x	x	x
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	D3	All	All	x	x	
M2b	Situational Awareness, Monitoring & Analytics (Max)	D3	All	All			x
M3	Distribution System Stress Reduction Program		O1A	R		x	

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE risk-models mitigations in this RAMP report.)

Consequence Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial - F

A. M1 – Climate Adaptation & Severe Weather Program Description

SCE formally implemented this program in 2018 and plans to continue this effort through the RAMP period as a long-term effort to centralize the Climate Adaptation and Severe Weather efforts across the Company. The program comprises SMEs from different organizational units (Transmission & Distribution, Generation, Corporate Real Estate, Business Resiliency, Information Technology, Policy & Community Engagement, and Strategic Planning), and external consultants in the climate change field. This program primarily seeks to better understand the impacts of climate change on our grid and facilities, and develop adaptation strategies to address climate impacts over time.

This program will identify the appropriate framework and criteria to assess and mitigate climate risks and coordinate the use of this framework company-wide. Specifically, the program seeks to:

- Modify business processes (e.g., energy procurement and demand forecasting, engineering and equipment procurement, customer service, power generation and delivery, and system design and planning) to enhance SCE's resilience to potential climate impacts;
- Develop an investment and programming strategy and implementation plan to address near-, medium-, and long-term impacts;
- Identify indicators to monitor over time to inform decision making;

[57] Please refer to WP Ch. 12, pp. 12.43 – 12.52 *(RAMP Mitigation Reductions)*.

[58] For M1, only impacts to O1A and O1B were modeled due to insufficient data to model the mitigation effectiveness on other outcomes.

- Harden assets and infrastructure (e.g., buildings, IT, electric and generation infrastructure) in response to potential climate impacts;
- Change engineering criteria and standards to modify to enhance asset and system resilience;
- Update maintenance practices (e.g. inspection schedules, and preemptive replacement approaches) to enhance asset and system resilience; and
- Advance SCE climate strategy through policy action and external engagement.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Currently, the program performs analyses to inform seasonal weather outlooks and storm preparedness efforts. This enables proactive planning for potentially severe weather events. In other words, this mitigation can reduce the consequences associated with major and catastrophic weather events on our system.

In the future, all outcomes and consequences will be targeted and potentially impacted by this mitigation. The Climate Adaptation and Severe Weather Program is currently conducting vulnerability assessments that will inform the types of mitigation activities that will also address O2A (Higher Energy Procurement Costs) and O2B (Exceptional Energy Procurement Cost). Please see Appendix 1 for additional information.

B. M2a – Situational Awareness, Monitoring & Analytics (Optimal)

Situational awareness is critical to SCE's operational decision-making and service delivery. Situational awareness gives SCE visibility to critical system operations, weather conditions across the system at different degrees of granularity, and other externalities that affect the daily operation of the grid. SCE has historically maintained this capability by coordinating information, analytics, and monitoring through the use of a 24-hour a day "Watch Office" that receives and disseminates critical information across the Company.

The Situational Awareness Center (SA Center) is currently operated by three meteorologists who provide weather forecasts, analytics, and hazard advisories to support executing core business functions. SCE intends to add two additional meteorologists in the fourth quarter of 2018. These additional meteorologists will support increasing workloads in the SA Center and help build capabilities in wildfire mitigation. The SA Center also assists electricity demand forecasting and enhances the execution of work in the field. The SA Center is being equipped with advanced computer systems that simultaneously run several meteorology applications and integrate information collected from monitoring devices such as weather stations and HD

Cameras. This will increase our capacity to better forecast weather and climate-related events, and will help inform decision-making during regular operations and during incidents.

a. Weather Stations

Weather stations are pieces of equipment containing sensors that capture and transmit weather data, including wind speed, humidity, etc. This real-time weather information can be used to monitor weather and validate weather models.

SCE evaluated existing weather forecasting and assessment products and services offered by vendors, as alternatives to the deployment of this mitigation. However, the weather forecasting and assessment models available through these existing tools rely on limited reliable weather sensor data in high fire risk areas. To improve the accuracy and specificity of weather data to support operational decisions, there is a strong case for installing additional weather stations and HD cameras with specific circuit-level detail to provide more granular information that is not achievable through other off-the-shelf weather forecasting products and services.

SCE's pre-existing weather stations were installed over twenty years ago, and while still in use, lack the precision and capabilities of modern-day technologies. Furthermore, these legacy weather stations were deployed in substations and not on distribution lines in high fire risk areas. They do not directly support SCE's objective to forecast and assess high fire conditions that may warrant preemptive de-energization.

SCE intends to install additional weather stations on circuits in high fire risk areas, including up to a total of 125 stations by the end of 2018, and an additional 725 weather stations from 2019 – 2020. This results in a total network of about 850 weather stations throughout the SCE high fire risk areas. SCE has established a distribution overhead standard and installation guide, which is being used by distribution crews to install these units. Once we reach the desired level of deployment of 850 weather stations, SCE believes we will have improved granularity in weather data to more effectively forecast weather conditions at the circuit level and inform critical operational decisions during extreme weather events.

b. High Definition (HD) Cameras

Wildfires frequently start as smaller versions of brushfires before they grow and become catastrophic events. To minimize the growth and propagation of fires and help with fire suppression efforts, SCE is partnering with the University of California, San Diego (UCSD) to procure, install and maintain pan-tilt-zoom HD Cameras at up to 80 sites. These cameras can spot fires from a 100-mile radius and determine the size and approximate location of the fire. SCE is targeting these cameras to provide up to 90 percent coverage of SCE's high fire risk area.

UCSD is serving as a technical, research, and execution partner for deploying the weather stations. SCE is working with the Orange County Fire Department (OCFD) on an initial roll-out, and will begin incorporating counties and fire agencies throughout SCE's high fire risk area to provide HD Camera live feeds. This information is critical to fire agencies for effectively deploying air and ground resources to limit and contain fires in the early stages.

c. Advanced Weather Modeling Tool

In addition to the integrated weather monitoring devices (weather stations and HD Cameras) mentioned above, SCE contracted with IBM, an international leader in weather modeling, to develop an advanced modeling tool. This tool will provide more frequent, higher-resolution forecast data on one comprehensive platform, including information gained from SCE's weather stations. The tool will provide higher-resolution forecast information down to 500m, and short-term forecast updates as frequently as every 15 minutes. This is faster than SCE's current models, which are mainly run on six- or twelve-hour cycles and at resolutions of 3km or greater. The model will forecast weather parameters such as temperature, wind speed and gusts, humidity, and precipitation. This system will provide these benefits:

- Enhanced resolution and more accurate forecast data to better inform deploying SCE's PSPS protocol;
- Severe weather forecasting including wind, thunderstorms, and heavy rain events along with extreme temperatures;
- Visualization of weather conditions and forecasts around SCE infrastructure; and
- Overall support to SCE's IMT in developing HFRA forecasts and fire response plans.

IBM has delivered an initial functional forecasting model and visualization tool. IBM is currently developing enhancements to the initial release of the software, and will add additional capabilities and features in future phased releases.

d. Advanced Modeling Computer Hardware

The advanced capabilities described above will require advanced computing power and speed to efficiently and reliably predict wildfire threats and other hazards. SCE will procure advanced computer hardware and deploy state-of-the-art software to run a sophisticated Fire Potential Index model. The model will account for various factors including weather, live fuel moisture, and dead fuel moisture to assess the level of risk of wildfire ignitions. This platform will also enable software that analyzes decades of data for fuel and weather characteristics from past wildfire ignitions, and compares and contrasts those variables against current conditions to forecast the Fire Potential Index. The output from this model will be used to inform operational decisions, implement work restrictions, and optimize resource allocation for emergency situations. SCE is obtaining the hardware and software for its high-performance computing platform, and intends to begin using it in 2019.

1. Drivers Impacted

This mitigation will reduce effects of D3 – extreme wildfire events. If we can more quickly spot developing fires, we can enable faster responses to contain the fire. SCE is focused on accessing more detailed information about wildfire risk at the individual circuit level, to better understand how weather conditions might impact utility infrastructure and public safety in high fire risk areas. This plan includes contracting with IBM to access a high-resolution weather model and purchasing a high-performance computer platform that will aggregate complex data to generate geographically-based fire potential indices to approximate wildfire risk across SCE's service area.

Coupled with deploying additional weather stations and HD cameras, these new capabilities will better inform operational decisions, help SCE's emergency management staff determine how best to reduce potential wildfire risks, and make us even more effective at responding to fire events when they occur. Because technology is critical to this effort, and is always evolving, SCE is exploring the use of alternative technologies in parallel with utilizing the proven technology being used today. Our approach includes a program study to support a high-resolution weather forecast tool.

2. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Increased situational awareness will enable SCE to better forecast the impacts of extreme events on our generation, corporate real estate, and telecommunication assets as well as impacts on business processes. This mitigation will enable the Company to take early action (such as pre-staging of resources and activation incident management teams) to pre-plan our response. This lets us make quicker decisions regarding how and when to restore power when an extreme event occurs.

This mitigation may also improve response time, which in turn may reduce outage times. Greater awareness of emerging weather events will allow us to plan upfront and appropriately modify work procedures to improve the safety of our workers and the communities we serve.

b. O2A – Higher Energy Procurement Cost and O2B – Exceptional Energy Procurement Cost

Highly accurate weather forecasts are critical in determining SCE's generation capacity on hot weather days. Accurate weather forecasts are also needed to accurately forecast load for day-ahead market transactions. An accurate weather and load forecast allows for a more informed assessment of financial risk. This assessment of financial risk helps determine hedging strategies as well as the potential need to purchase energy on the spot market.

Exceptionally high energy procurement cost incidents are difficult to predict,[59] so it becomes even more important to have quality weather and demand forecasts. Advanced weather modeling may foster greater integration of additional weather variables tailored to improve load forecast projections with more accurate and granular weather forecast information.

C. M2b – Situational Awareness, Monitoring & Analytics (2600 weather stations)

This mitigation includes all components of M2a, but adds additional weather stations to the scope. This mitigation would install 2,600 weather stations (two per circuit for each of the 1,300 circuits in HFRAs) in order to attain the higher limit considered for installation. However, SCE benchmarked with San Diego Gas and Electric (SDG&E) and obtained a ratio of 1:5 for weather stations to HFRA square miles. This ratio equates to 850 weather stations for the identified HFRAs.[60]

D. M3 – Distribution System Stress Reduction Program

SCE typically replaces distribution assets, such as transformers, when they fail in service, or when we observe deterioration during inspection or other fieldwork. Deterioration may include leaks, corrosion, and damage caused by vehicle collisions or acts of nature. Climate change-driven weather conditions, including extreme heat events, can make these assets more susceptible to breaking down earlier than expected. This mitigation would proactively replace

[59] These incidents can occur due to compounding factors that inflate price of electricity. One example is a natural gas shortage occurring during a heatwave.
[60] Please refer to WP Ch. 12, p. 12.53 *(Number of Weather Stations)*.

distribution transformers prior to failure. SCE would target this effort in disadvantaged communities (DACs) that may feel an exceptional burden or hardship due to an outage.

SCE's initial effort on this mitigation, while still conceptual, will focus on DACs, prioritizing proactively replacing overloaded or deteriorated equipment identified for future replacement at some point, but not yet addressed because of resource limitations. This work would target specific geographic locations believed to be climate-vulnerable using the California Environmental Protection Agency's ("CalEPA") definition.[61]

1. Outcomes & Consequences Impacted

a. O1A – Impacts from Major Weather Events

Reliability impacts to customers will be reduced by proactively replacing aging equipment before equipment failure occurs.

Climate hazards tend to have disproportionate impacts on disadvantaged communities. For example, those who may experience power outages in these communities may not have the resources to find alternative means to power medical equipment, or may have to endure extended periods of dealing with heat or cold as they may not have the ability to relocate temporarily. Given these circumstances, it is prudent to explore various mitigation strategies to offset the potential for weather-related outages in these communities.

E. Additional Mitigations Discussed in other Chapters

Similar to our discussion in Section III, there are two mitigations proposed in the Wildfire chapter that also likely provide some degree of benefit for this chapter. Table IV-2 contains a summary of these two proposed mitigations that are modeled in the Wildfire chapter but that also provide benefits for reducing climate change risks.

[61] CalEPA specifies disadvantaged communities (DACs) to be the 25% highest scoring census tracts in the state along with the 22 census tracts that score in the highest 5% of CalEnviroScreen's pollution burden, but which have no overall CalEnviroScreen score because of unreliable socioeconomic or health data. This definition is consistent with the use of the California Communities Environmental Health Screening Tool Version 3 ("CalEnviroScreen 3.0") in other Commission proceedings. CalEnviroScreen scores are based on pollution burden and population characteristic indicators. Other tools such as California's Healthy Places Index may also help identify target areas.

Table IV-2 – Mitigations Proposed in Wildfire Chapter that have Benefits to Climate Change Chapter		
Wildfire Chapter Mitigation	**Mitigation Description**	**Likely Benefits for Climate Change Chapter**
M5 – Expanded Vegetation Management	SCE plans to expand its vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated. SCE views this as an important effort in light of increasing winds that have the potential to blow debris into utility lines from even greater distances.	Tree pruning and removal as far as 200 feet away from SCE's electrical facilities can help reduce the amount of fuel near SCE's infrastructure.
M9 – Fire Resistant Poles	At locations where SCE is installing covered conductor in HFRA and pole replacements are required, SCE will use fire-resistant composite poles, where appropriate, instead of traditional wood poles. These poles are specifically designed to withstand wildfires, which will harden the distribution system.	The installation of fire-resistant composite poles could decrease risk to SCE's infrastructure from non-utility-associated wildfires (e.g., wildfires caused by lightning strikes, arson, etc.).

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Section III and IV and has developed a Proposed Plan to address this near-term risk, as shown in Table V-1 below.

Table V-1 - Proposed Plan (2018 – 2023 Total Costs and Risk Reduction)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	**Name**	**Start Date**	**End Date**	**Capital**	**O&M**	**MRR**	**RSE**	**MRR**	**RSE**
C1	Emergency Management	2018	2023	$0.0	$21.3	2.24	0.10	7.46	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.02	0.22	1.99	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.65	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.08	0.11
			Total - Proposed Plan	**$26.8**	**$56.4**	**6.32**	**0.08**	**18.18**	**0.22**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

The Proposed Plan combines existing controls and new mitigations that will reduce the impacts of severe weather and climate change on our system. On an annualized basis and using mean results, the Proposed Plan would reduce potential serious injuries down to approximately one per year; reduce potential fatalities by nearly half to a number close to zero per year; reduce CMI by approximately 28 million per year; and reduce financial consequences by approximately $45 million per year.

B. Execution Feasibility

SCE believes it can continue to execute the existing controls in this plan (C1 – Emergency Management and C2 – Fire Management Program). We have performed these activities for years, and we have proven processes and capabilities. SCE does not see substantial constraints in being able to execute on the Proposed Plan's new mitigations. Specifically, SCE has determined the optimal number of weather stations to deploy as part of M2a – Situational Awareness. SCE evaluated the pace of deploying the new equipment in M2a against the resources available to deploy it, and found this level and pace of deployment is feasible. In addition, SCE has already deployed over 100 of these weather stations this year. SCE is utilizing vendors that have worked on similar projects to install weather stations and HD Cameras for other California IOUs to help ensure successful deployment and service.

SCE evaluated the technical constraints of deploying this plan. For example, specific requirements for installing weather stations could restrict the volume of stations deployed, including:

- Access to facilities, right-of-way condition, road conditions;
- Public lands sensitivity (e.g. National Forest);
- Acceptable cell coverage for transmitting weather data;
- Poles should ideally be accessible by bucket truck without impacting traffic;
- The weather stations must be mounted at least 20 feet above the ground;
- Poles should have a clear view of southern sky; and
- Presence of equipment on pole that would prevent a weather station from being safely installed.

Based on SCE's evaluation, these requirements pose no issue in deploying the Proposed Plan.

C. Affordability

The Proposed Plan is the least-cost option and has the highest RSE compared to the alternative plans (Proposed RSE = 0.08; Alternative #1 RSE = 0.06; and Alternative #2 RSE = 0.05). Based on these results, the Proposed Plan provides greater value to our customers and for our operations compared to the alternative plans.

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an alternative plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	**Name**	**Start Date**	**End Date**	**Capital**	**O&M**	**MRR**	**RSE**	**MRR**	**RSE**
C1	Emergency Management	2018	2023	$0.0	$21.3	2.23	0.10	7.44	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.64	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.07	0.11
M3	Distribution System Stress Reduction Program	2018	2023	$25.0	$0.0	0.08	0.00	0.17	0.01
	Total - Alternative Plan #1			**$51.8**	**$56.4**	**6.38**	**0.06**	**18.30**	**0.17**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

Alternative Plan #1 contains all the same controls and mitigations included in the Proposed Plan, but includes one additional mitigation M3 (Distribution System Stress Reduction Program). As discussed in Section IV, this mitigation focuses on proactively replacing equipment that may be susceptible to overloading in hot weather conditions. Proactively replacing this equipment potentially provides direct reliability benefits, and consequently may provide relief to individuals who lack alternative means to deal with power outages. This mitigation would replace 200 distribution transformers annually to reduce the customer minutes of interruption experienced when an overloaded transformer breaks down.

SCE believes that a proactive replacement program targeted in climate-vulnerable DACs could be a viable future mitigation. However, at this time, this mitigation is still at the conceptual design phase. SCE must perform further engineering studies and work management efforts before this mitigation is ready to be broadly deployed. We will continue to carefully evaluate this program for future consideration.

Alternative Plan #1 achieves approximately the same safety, reliability and financial consequence reductions as the Proposed Plan. But it does so at a higher cost.

B. Execution Feasibility

In discussing the Proposed Plan, we explain the execution feasibility of the first four activities in this plan (C1, C2, M1, and M2a). The conceptual mitigation M3 (Distribution Stress Reduction Program) requires further validation through additional studies to determine the appropriate scope of work and to identify the appropriate areas of our service territory where this would be deployed. SCE must also gain a better understanding of the resource requirements for executing this work, and balance the need for the work against other high priority grid-related work.

C. Affordability

The cost of Alternative Plan #1 is approximately 30% more than the Proposed Plan. This increased cost does not come with a commensurate increase in risk reduction. As a result, the RSE of this plan is substantially lower than the Proposed Plan (0.06 vs 0.08, respectively).

D. Other Considerations

This plan would involve outage coordination constraints involved with proactively replacing distribution transformers to help minimize service reliability impacts to customers.

VII. Alternative Plan #2

The third option that SCE evaluated is Alternative Plan #2, as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.21	0.10	7.36	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.80	0.33	2.62	1.07
M2b	Situational Awareness, Monitoring & Analytics (Max)	2018	2023	$56.8	$35.9	2.59	0.03	7.44	0.08
			Total - Alternative Plan #2	**$56.8**	**$64.3**	**6.61**	**0.05**	**19.39**	**0.16**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

Alternative Plan #2 includes the same controls and one of the same mitigations (M1 – Climate Adaptation & Severe Weather Program) as the Proposed Plan. However, Alternative Plan #2 replaces M2a (Situational Awareness, Monitoring & Analytics – Optimal) with M2b (Situational Awareness, Monitoring & Analytics – Max).

M2b proposes deploying 2,600 weather stations instead of the 850 weather stations deployed in M2a. This level of deployment would place two weather stations on each of the 1,300 identified circuits in SCE high fire risk areas.

While this level of deployment would provide much more granularity than M2a, a cross-functional project team (meteorologists, grid operations, and distribution system personnel) determined that 850 weather stations will be sufficient to provide high resolution weather data after benchmarking with SDG&E to evaluate the ratio of weather stations to HFRA square miles.[62]

B. Execution Feasibility

Compared to the Proposed Plan, Alternative Plan #2 will require more resources to install the increased number of weather stations. The weather station count is about three times as many as in the Proposed Plan. To deploy this volume of weather stations, SCE would likely have to de-prioritize other work to accommodate resource constraints.

[62] Please refer to WP Ch. 12, p. 12.53 *(Number of Weather Stations)*.

C. Affordability

Alternative Plan #2 achieves approximately the same reductions to safety, reliability and financial consequences as the Proposed Plan. However, the cost of Alternative Plan #2 is approximately 43% higher. As a result, the RSE of Alternative Plan #2 is significantly lower than the Proposed Plan's RSE (Alternative #2 RSE = 0.05; Proposed RSE = 0.08; and Alternative #1 RSE = 0.06).

The increased costs are due to installing the additional 1,750 weather stations compared to the Proposed Plan. The level of deploying weather stations in the Proposed Plan is adequate to begin with. The Proposed Plan leaves open the option to deploy additional weather stations if future analysis and circumstances indicate that incremental value would be achieved by doing so.

D. Other Considerations

The quantity of weather stations contemplated in this plan may be above the optimal number of weather stations needed to make critical operational decisions. SCE will assess the need for additional weather stations in the coming years as it deploys the level of weather stations prescribed in the Proposed Plan.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

1. Future risks analyses should address all climate change impacts

In this immediate RAMP analysis, we could only model the event-based climate drivers using RAMP risk model. By not analyzing the full suite of climate threats posed to the Company in the near-term, we could not present and evaluate the full risk to our business from a changing climate in the quantitative RAMP risk analysis. We also could not evaluate the full risk reduction benefits and RSE of the controls and mitigations contemplated in this report, as the RAMP model only captured impacts from 2018-2023. SCE expects to learn and to expand our capabilities to more fully capture all climate change risks in future modeling efforts. SCE intends that its 2021 GRC incorporate the results of the Climate Change Vulnerability and Impact Assessment presented in Appendix 1.

2. Uncertainty in driver quantification

Due to natural variability and randomness in climate systems, there can be substantial uncertainty in developing climate driver projections for the near term (i.e., 0 to 10 years from present).[63,64,65] As a result, it is important to classify the climate driver projections used in the RAMP model as directional and subject to change.

B. Data Collection & Availability

The data used to derive inputs to the RAMP model were founded on academic research, SCE data, and input from internal and external climatologists, meteorologists, and other experts.[66] However, SCE understands that the climate adaptation space is rapidly evolving, and there is ongoing discussion around the data that should be used to evaluate and model the

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[63] Strategic Environmental Research and Development Program (SERDP) (2016) Climate-Sensitive Decision-Making in the Department of Defense: Synthesis of Ongoing Research and Current Recommendations. US Department of Defense.

[64] Walsh, J; Wuebbles, D; Hayhoe, K; Kossin, J; Kunkel, K; Stephens, G; Thorne, P; Vose, R; Wehner, M; Willis, J; Anderson, D; Kharin, V; Knutson, T; Landerer, F; Lenton, T; Kennedy, J; Somerville, R (2014) Appendix 3: Climate Science Supplement. Climate Change Impacts in the United States: The Third National Climate Assessment, Melillo, JM; Richmond, TC; Yohe, GW; Eds., U.S. Global Change Research Program, 735-789. doi:10.7930/J0KS6PHH.

[65] Flato, G; Marotzke, J; Abiodun, B; Braconnot, P; Chou, SC; Collins, W; Cox, P; Driouech, F; Emori, S; Eyring, V; Forest, C; Gleckler, P; Guilyardi, E; Jakob, C; Kattsov, V; Reason, C; Rummukainen, M (2013) Evaluation of Climate Models. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[66] Please refer to WP Ch. 12, p. 12.54 *(Subject Matter Expert Qualifications)*.

impacts of climate change. SCE has used the best reasonably-available data and information to develop this RAMP risk chapter, and we intend to fully support the climate adaptation community in further developing the breadth and depth of data to improve and refine future climate change analyses.

C. Performance Metrics

Many of the mitigations proposed in this RAMP report are brand-new to the Company and performance metrics to assess their effectiveness are not yet available. SCE will be developing metrics as part of the Climate Adaptation and Severe Weather Program's work during the next few years. Metrics that SCE will likely consider include:

- Number of times SCE HD Cameras identify fires first, or are used by fire agencies to identify and assess fire size, deploy resources and determine containment techniques.
- Metrics around using advanced modeling capabilities to provide advanced preparation and staging of resources ahead of major storm events.

Appendix 1

Near-, Medium-, and Long-term (2018 – 2050) Climate Change Vulnerability and Impact Assessment

IX. Appendix 1 – Near-, Medium-, and Long-term Climate Change Vulnerability and Impact Assessment

A. Introduction

This section describes the Climate Change Vulnerability and Impact Assessment that SCE is currently conducting to identify comprehensive priority climate impacts, develop climate projections for the 2018-2023, 2030, and 2050 time horizons, and produce an actionable adaptation plan to mitigate the potential climate change impacts facing SCE. The first draft of the Climate Change Vulnerability and Impact Assessment report will be developed by December of 2018. The report will help refine the Proposed Plan described in Section V, by including additional mitigations as applicable that address the more gradual impacts of climate change that should also be considered over the RAMP period.[67]

The following sections describe the process of this vulnerability and impact assessment, and the findings to date. This includes:

- The Climate Change Vulnerability and Impact Assessment framework;
- Potential climate impacts to SCE's assets and business processes; and,
- The approach for implementing adaptation measures over time.

B. Climate Change Vulnerability and Impact Assessment Framework

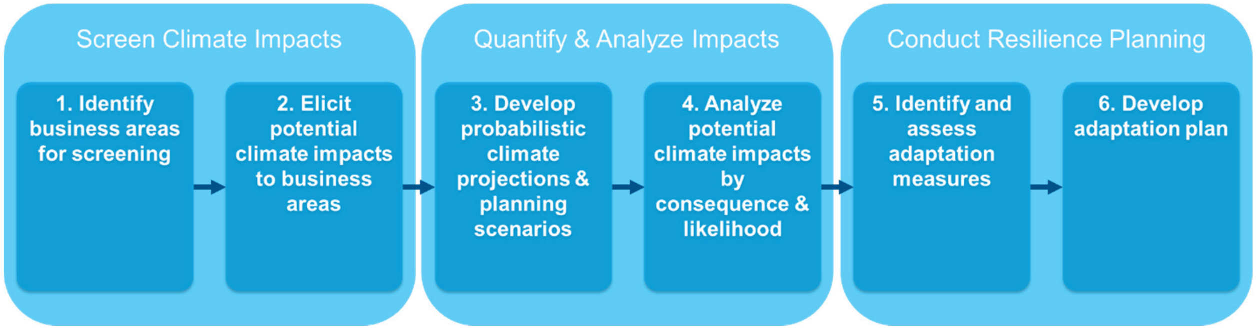
The framework to analyze potential near-, medium-, and long-term (2018-2023, 2030, and 2050) climate takes a decision-first approach.[68] The analysis is designed to identify and quantify potential impacts, and then produce an actionable adaptation plan that sets forth a portfolio of climate change adaptation mitigation measures.

The framework begins with interviewing internal experts to identify potential climate impacts facing SCE, as well as reviewing the established literature to capture all potential impacts. SCE then built climate projections that draw on best available climate science for climate variables that drive the impacts. The impacts are then assessed based on the projected magnitude of change in the variables. These outputs are used to inform adaptation planning, and help craft a suite of adaptation measures that are designed to mitigate impacts. Figure IX-1 below depicts this framework.

[67] The results of this report may influence the portfolio of mitigations that we submit as part of SCE's 2021 GRC.

[68] A decision-first approach is one that focuses on developing products to inform and improve decisions.

Figure IX-1 – Long-term (2030 and 2050) climate change vulnerability and impact assessment framework



1. Screen Climate Impacts

As summarized above, the climate change vulnerability and impact analysis begins with a rapid screening of the potential climate impacts relevant to SCE. The screening relies heavily on SME input and readily-available data to efficiently identify the key areas of SCE's business that may be impacted by a changing climate. The interviews were supplemented by reviewing literature to help ensure that known impacts that may not have been captured within the SME interviews were incorporated into the screening. The screening explored all aspects of SCE's business, and led to prioritizing potential impacts to be further considered and analyzed.

For each of the relevant aspects of SCE's business (i.e., assets, operations, demand forecasting, planning, grid modernization, and community engagement programs), SCE SMEs provided input into the climate impacts of greatest concern and how climate hazards affect assets and infrastructure, business processes, and externally-facing programs. Using a questionnaire and a series of semi-structured interviews, SCE documented the key climate hazards and variables that are important to each business area.

2. Quantify and Analyze Impacts

Based on the information gathered through the screening of climate impacts, SCE will analyze the impacts. We will quantify the impact wherever possible.

Notably, the methodology for developing future climate driver values differs between the near-term (2018 – 2023) and the medium- and long-term (2030 and 2050) components of this vulnerability and impact assessment. When developing predictions for conditions fewer than five years in the future, it is less beneficial to use climate models, whereas in the longer term (10+ years out), climate modeling is more appropriate. As a result, the near-term component of the vulnerability and impact assessment will draw upon academic literature and best available science for generating predictions for five-year time horizons.

Meanwhile, in the 2030 and 2050 time horizon analysis, SCE will use probabilistic climate projections for climate hazards where scientific support exists for doing so. Examples are changes in sea level, temperatures, and precipitation. In addition, for climate hazards without probabilistic climate information, SCE will develop projections of change in the variable or will use literature to provide information on expected trends. For priority cascading and compounding hazards, SCE will develop a set of high-impact planning scenarios to inform adaptation needs.

For the 2030 and 2050 time horizon analyses, SCE will rely on climate model information, primarily sourced from Localized Constructed Analogs data available via Cal-Adapt and released through California's Fourth Climate Change Assessment. This climate data will be processed to produce probabilistic climate projections that provide information on expected change and help assess impacts. The climate model information captures change in key climate variables due to greenhouse gas-caused warming, which becomes a more significant factor over time.

SCE will also conduct more in-depth analyses to characterize potential impacts by combining climate information with information about SCE's assets, operations, and planning processes. For instance, SCE plans to overlay maps of extreme heat projections with maps of customer demographic factors that exacerbate sensitivity to extreme heat impacts (e.g., age, income levels). In this way, we can identify areas that are particularly vulnerable and might require additional customer programs. Similar analyses will be conducted based on SME input on the type of analysis that can best inform adaptation needs and next steps.

The impact assessment will score impacts by level of consequence using SCE's impact matrix, which is based on likelihood and magnitude. The impacts will be weighted by impact type (e.g., financial, safety, reliability) and impact distribution (e.g., disadvantaged communities). SCE will then use workshops with SMEs to validate and refine consequence scores and identify any broader implications. The workshops will also help identify existing and potential adaptation measures.

3. Conduct Adaptation Planning

SCE will use the vulnerability and impact assessment results to inform adaptation planning. This includes identifying potential adaptation measures and developing an actionable adaptation plan.

Building on the findings of the workshops, SCE will identify preliminary descriptions of incremental and transformational adaptation measures at a conceptual level. These measures will be designed to address impacts across SCE's assets, operations, planning, grid modernization, and community engagement activities. Measures may address acute needs, such as changes to emergency management protocols, or more general needs, such as establishing a process for changing design standards to incorporate future climate conditions. The measures may also include ways SCE can build capabilities across its lines of business to better manage impacts from climate change and extreme weather. The measures will be evaluated based on a variety of elements, such as feasibility, flexibility, effectiveness for multiple hazards, synergies across impact areas, and cost.

C. Priority Climate Impacts to SCE's Assets and Business Processes

Several climate hazards can potentially harm SCE's assets and business processes by 2018-2023, 2030, and 2050. These hazards include temperature, extreme precipitation, drought and snowpack, wildfires, and sea level rise and coastal flooding. The impacts these hazards pose to the safety, reliability, and affordability of SCE's electricity are described below; these were identified through reviewing applicable literature and interviewing SCE SMEs. These impacts align with those included in SCE's response to the CPUC Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation. This section provides a general overview of projected changes in key climate conditions. More detailed climate information will be developed to support the impact analysis, as required.

In addition to specific standalone hazard impacts, we see compounding issues in various locations in SCE's service territory, which must be further evaluated.

1. Average & Extreme Temperatures

Average temperatures are projected to increase, and heat waves are projected to become more intense and more frequent.[69] Existing scientific literature and State data sources (i.e., Cal-Adapt) provide information that indicates expected changes in temperature in the SCE territory.

Increased average temperatures, and particularly increased extreme heat, have the potential to increase stress on SCE's system, as described in Table IX-1, below. Notably, these are examples rather than a comprehensive list. Additionally, changes in non-climate parameters, such as the spatial distribution of population growth, can potentially influence which parts of SCE's system experience the greatest impacts.

[69] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf

Table IX-1 – Potential increased temperature impacts to SCE's system	
Business Line Affected	**Potential impact**
Information Technology & Telecommunications	Increased air conditioning costs in telecommunication buildings
Transmission & Distribution	Reduced substation & transformer capacity and efficiency
	Overhead conductor, connector, and hardware failure
	Reduced efficiency of T&D lines
	Increased line sag
	Inverters disconnecting from grid
Generation: Thermal	Reduced generation capacity and efficiency
Generation: Hydropower	Reduced generation capacity and efficiency
	Increased evaporation of water within conveyance systems and reservoirs
	Increased likelihood of exceedance of outflow temperature limits
Generation: Wind	Reduced output
Generation: Solar Photovoltaic	Reduced generation capacity and efficiency

2. Average & Extreme Precipitation, Wind, Storms, Snowpack; Severity of Drought

The extreme precipitation events are projected to slightly increase in frequency and intensity in the medium and long-term due to climate change.[70] These changes are projected to affect SCE's infrastructure and operations in a variety of ways. Examples of the potential impacts are described in Table IX-2, below.

SCE's internal analysis projects a dramatic rise in January precipitation (+ 151 mm per month and runoff +23 mm per month) at some of our hydropower facilities between now and mid-century. The impacts on hydropower generation require additional study, because specific data points fail to represent the cumulative watershed impacts of this data set. SCE will engage in this analysis in the future.

Notably, longer-term extreme precipitation projections differ from the more near-term RAMP extreme precipitation driver (D1), which is expected to decrease slightly. This discrepancy may be because historical trends in the annual number of 99th percentile extreme rain events may not be a useful proxy for representing longer-term trends in extreme precipitation. Climate change models currently are not designed for modeling near-term climate.

[70] Swain, D. L., Langenbrunner, B., Neelin, J. D., & Hall, A. 2018. Increasing precipitation volatility in twenty-first-century California. Nature Climate Change, 8(5), 427.

Table IX-2 – Potential extreme precipitation, wind, & storm impacts to SCE's system

Business Line Affected	Potential impact
All Infrastructure	Increased flooding leading to damage of electrical equipment
	Increased flooding leading to damage to infrastructure from debris carried by floodwaters
	Inundation of access roads, inhibiting site access
	Debris flow
Information Technology & Telecommunications	Scouring and potential toppling of telecommunication poles
	Inundation of buildings, including data centers, leading to limited use and potential damage to equipment inside of buildings
	Communication failure due to flooding of splice cases and vaults
Transmission & Distribution	Scouring and potential toppling of T&D poles and towers
	Inundation of and damage to substation equipment, should flooding exceed 100-year flood levels, the standard to which substations are designed
	Lightning has the potential to damage assets
	Damage from extreme winds; lines are designed to 100-year wind speeds
Generation: Hydropower	Overflow of conveyance systems
	Depending on magnitude of precipitation and reservoir capacity and design, flooding can increase generation and replenish reservoirs, or result in excess spilling of water
	Increased flooding of surrounding communities
	Turbine damage from increased sedimentation and siltation
Workforce	Inundation limiting the ability of employees to travel to and from work

In California, climate change is projected to lead to more intense and frequent droughts, and reduced snowpack.[71] This is primarily expected to impact generation resources, as described in Table IX-3 below. Notably, these are examples rather than a comprehensive list.

[71] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf

Table IX-3 – Potential snowpack, drought, and average precipitation impacts to SCE's system	
Business Line Affected	**Potential impact**
Transmission & Distribution	Increased potential for subsidence, potentially leading to reduced stability of transmission and distribution infrastructure
Generation: Thermal	Reduced cooling water availability
Generation: Hydropower	Reduced water available for generation, resulting in reduced generation capacity
	Lower reservoir water levels leading to cavitation of runners and damage to blades
Catalina	Water supply shortage

3. Frequency and Severity of Wildfire

Wildfires are projected to increase in frequency and severity under climate change.[72] Potential wildfire-related impacts to SCE's system are described in Table IX-4 – Potential wildfire impacts to SCE's system. Notably, these are examples rather than a comprehensive list. Additionally, future changes in wildfire are impacted by non-climate variables, such as urbanization, de-urbanization, and changes in the urban-wildland interface.

Table IX-4 – Potential wildfire impacts to SCE's system	
Business Line Affected	**Potential Impact**
All Infrastructure	Equipment damage and failure
	Limited site accessibility
Workforce	Limited ability of employees to safely access infrastructure, exacerbating repair and recovery times

4. Sea Level Rise, Wave Run-up, & Coastal Flooding

Sea levels are projected to increase at an accelerating pace, leading to increased coastal inundation.[73] Potential impacts from sea level rise are described in Table IX-5 below. This table represents examples rather than a comprehensive list.

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[72] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf

[73] *Id.*

Table IX-5 – Potential sea level rise, wave run-up, and coastal inundation impacts to SCE's system

Business Line Affected	Potential impact
All Infrastructure	Increased flooding leading to damage of electrical equipment
	Increased flooding leading to damage to infrastructure from debris carried by floodwaters
	Inundation of access roads, inhibiting site access
	Saltwater intrusion leading to inundation and corrosion of coastal infrastructure lacking corrosion protection
Information Technology & Telecommunications	Scouring and potential toppling of telecommunication poles
	Inundation of buildings, including data centers, leading to limited use and potential damage to equipment inside of buildings
	Communication failure due to flooding of splice cases and vaults
Transmission & Distribution	Scouring and potential toppling of T&D poles and towers
	Inundation of and damage to substation equipment, should flooding exceed 100-year flood levels, the standard to which substations are designed
Catalina	Saltwater intrusion into water supply wells
Workforce	Inundation limiting the ability of employees to travel to and from work

5. Soil Stability & Ecology (Landslides, Mudslides Subsidence, Vegetation, and other Ecological Variables)

Changes in soil stability and ecology also have the potential to impact SCE's level of vulnerability. For instance, increases in extreme rainfall have the potential to drive increases in landslides and mudslides. Additionally, increasing drought may lead to greater groundwater consumption, resulting in subsidence. The impacts identified in the table below are examples rather than a comprehensive list.

Table IX-6 – Potential soil stability and ecology impacts to SCE's system	
Business Line Affected	**Potential impact**
All Assets	Landslides and mudslides can lead to equipment destabilization and damage
	Subsidence can damage underground assets
	Shifts in vegetation can enhance or reduce wildfire risk
Information Technology & Telecommunications	Towers and overland pipelines can be affected if footings are within subsidence zones
Generation: Hydropower	Damage to canals or to supports and/or footings of penstocks or flumes within subsidence zones
Transmission & Distribution	Towers and overland pipelines can be affected if footings are within subsidence zones

D. Approach for Implementing Measures over Time

SCE is developing a flexible adaptation pathway approach[74] for investing in adaptation measures over time, so that we account for the uncertainty in future climate information. A flexible adaptation pathway approach helps manage future uncertainty by allowing decision-making to adjust based on new information or conditions (e.g., new technologies, customer needs, climate conditions, and economic and policy landscape). The flexible adaptation pathways approach has been adopted in other climate adaptation contexts, including for the City of New York and for a major infrastructure project along the Thames River in England.

The approach will support flexible implementation over time, taking advantage of new information as it becomes available that may reduce uncertainty or provide a "signpost" of how conditions are changing. Using this flexible approach, adaptation measures can be sequenced over time to protect against near-term changes, while leaving options open to protect against a range of plausible climate futures later in the century.

For example, SCE may select a pathway, beginning in 2020, to implement additional tide gauges to more closely monitor rising sea levels. Sea level might be selected as a signpost to track changes in conditions. Then, a trigger of four feet of sea level rise could be selected to trigger an adaptation pathway that physically protects infrastructure against inundation. The adaptation pathway might involve raising the height at which equipment sits.

[74] Hasnoot, M., Kwakkel, J.H., Walter, W.E., & ter Maat, J. (2013). Dynamic adaptive policy pathways: A method for crafting robust decisions for a deeply uncertain world. Global Environmental Change*,* 23(2), 485 – 498.

E. Conclusions

SCE is in the process of completing its comprehensive near-, medium-, and long-term Climate Change Vulnerability and Impact Assessment for the 2018-2023, 2030, and 2050 time periods. Because established results are not yet available to incorporate into this RAMP report, SCE will likely update its proposed climate change mitigation portfolio in its 2021 GRC submission with the results.

Early assessment findings indicate that increases in extreme heat waves are among the hazards of greatest concern, because such increases impact SCE's power generation, delivery, and demand in a variety of ways that may cumulatively reduce SCE's ability to meet customer needs. Our analysis has identified compounding and cascading impacts that arise from hazards as a substantial concern. We will continue to explore these areas to better prepare for and adapt to the changing climate.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix A
Nuclear Decommissioning

Rosemead, CA
November 15, 2018

Contents

I. BACKGROUND

In accordance with the request made by the Commission's Safety and Enforcement Division (SED), this appendix addresses the safety risks associated with the decommissioning of Southern California Edison's (SCE) San Onofre Nuclear Generating Station (SONGS).[1] As discussed below, SCE mitigates these safety risks by adhering to Nuclear Regulatory Commission (NRC) radiological safety regulations and other federal and state industrial safety regulatory agency requirements.

A. SONGS Location

SONGS is a three-unit nuclear generation facility located on the coast of southern California, in San Diego County, about 62 miles southeast of Los Angeles and 51 miles northwest of San Diego. The on-shore SONGS site is located within the boundaries of Marine Corps Base Camp Pendleton under easements granted by the U.S. Department of the Navy (Navy). The offshore sites, used for seawater intake and discharge conduits related to facility operations, are used pursuant to lease contracts with the California State Lands Commission (CSLC).

B. Shutdown Date

Unit 1 commenced commercial operations in 1968 and was permanently retired in 1992. Most of the onshore Unit 1 facilities were dismantled by 2009. The Unit 1 offshore conduits were partially dispositioned in 2014. All Unit 1 spent fuel was transferred from wet storage in the spent fuel pools to dry storage[2] in the on-site Independent Spent Fuel Storage Installation (ISFSI) during 2003-2005. The remaining Unit 1 structures are planned to be dispositioned concurrently with the decommissioning of Units 2 and 3.

Units 2 and 3 commenced commercial operations in 1983 and 1984, respectively, and were permanently retired in 2013. A portion of the Units 2 and 3 spent fuel was transferred from the spent fuel pools to the ISFSI during 2007-2012.[3] SCE now holds an NRC license that prohibits power operations, but authorizes the possession of the SONGS facilities and licensed nuclear material (spent fuel).

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[1] During one of SCE's initial pre-filing RAMP meetings with SED, SCE was requested to provide a qualitative assessment of the safety risks associated with the decommissioning of SONGS.
[2] After fuel has been used in a reactor, it is stored in pools that utilize active filtration and cooling systems. After a period of cooling, it can be moved to onsite dry storage, which does not rely on active operational systems. See Section IV of this appendix for additional details.
[3] From 1983-2007, all fuel from Units 2 and 3 was stored in the spent fuel pools.

SCE is currently planning the decontamination and dismantlement of SONGS. All remaining Units 2 and 3 spent fuel is scheduled to be transferred from the spent fuel pools to the ISFSI.

C. Decommissioning Governance

SCE is the majority owner of SONGS. San Diego Gas & Electric Company (SDG&E), and the City of Anaheim and the City of Riverside (the Cities), are minority participants in the ownership and/or decommissioning liability of SONGS. SCE, SDG&E, and the Cities are collectively referred to as the Participants.

On April 23, 2015, the Participants executed the SONGS Decommissioning Agreement. The Agreement designates SCE as the decommissioning agent, provides for the performance of decommissioning work, and identifies the separate rights, duties, and obligations of the Participants. The Agreement requires the Participants to restore the SONGS site in accordance with applicable federal and state regulations in an effective manner. It also requires unanimous agreement among the Participants for major decisions. Accordingly, the Participants collectively oversee the decommissioning project.

II. NRC JURISDICTION AND REGULATORY FRAMEWORK

A. Jurisdiction

Under the Atomic Energy Act of 1954, the federal government exercises exclusive jurisdiction over the nuclear and radiological safety aspects of nuclear energy generation. The courts have affirmed that Congress expressly and implicitly intended to preempt state regulation pertaining to nuclear facility operations and radiological safety, including the construction, operation, and decommissioning of licensed nuclear reactor facilities.[4] Based on both the express and implied Congressional intent, the individual States have no jurisdiction over nuclear facility operations and radiological safety matters. States may exercise their traditional authority over the need for generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like.[5]

B. NRC Regulatory Framework

Consistent with its pervasive regulatory authority over nuclear facility operations and radiological safety, the NRC has established a rigorous and comprehensive regulatory framework for all aspects of the nuclear facility life cycle, including facility design, licensing, construction, operation, decommissioning, radioactive waste transportation and disposal, and final site decontamination and restoration. The paramount priority of the NRC framework is to ensure all aspects of safety and regulation are initiated and upheld. This framework encompasses both operating nuclear facilities and decommissioned facilities. The intent is to protect public health and safety, promote security of radioactive materials, and protect the environment.

As a prerequisite to NRC licensing, each facility develops a comprehensive safety analysis report that evaluates all potential risks of facility operations and establishes risk mitigation strategies. Each facility has NRC-approved technical specifications that set forth specific parameters within which the facility must be operated. The NRC license is conditional

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[4] *See* Pacific Gas & Electric Company v. State Energy Resources Conservation and Development Commission, 461 U.S. 190 (1983), at 205 and 212; Northern States Power Co. v. Minnesota, 447 F.2d 1143, (8th Cir. 1971) at 1152-53 (The implied Congressional intent arises from the pervasiveness of the federal regulatory scheme that Congress directed and that the NRC (successor agency to the U.S. Atomic Energy Commission) has carried into effect through the promulgation and enforcement of detailed regulations governing the licensing of atomic power plants).

[5] *See* Pacific Gas & Electric Company v. State Energy Resources Conservation and Development Commission, 461 U.S. 190 (1983), at 205 and 212.

based on the facility's compliance with all such parameters. The NRC continuously oversees plant operations through various means, including the use of on-site inspectors and a robust enforcement program. Enforcement sanctions may include notices of violation, monetary fines, or orders to modify, suspend, or revoke a license or require specific actions because of a public health issue.

The NRC license for each nuclear facility remains in effect until the facility is decontaminated and decommissioned, and all federal requirements for license termination have been fulfilled by the licensee and verified by the NRC. Thus, SONGS will remain subject to the NRC's jurisdiction and regulatory framework until decommissioning and license termination are completed. NRC license termination is currently scheduled to be completed by 2051.

III. SONGS SAFETY PROGRAMS

Safety is paramount at SONGS and an SCE core value. SCE expects all workers at SONGS, whether utility employees or contractors, to perform all work safely and in accordance with NRC and other regulatory requirements. SCE goes to great lengths to ensure that all workers are properly trained and equipped to perform all SONGS decommissioning work safely.

A. SCE Safety Program

SCE is committed to maintaining a strong safety culture throughout company operations, including SONGS decommissioning. We do this by creating and sustaining a work environment that values:

- Having every employee leave the workplace unhurt;
- Using work behaviors and practices that uncompromisingly protect the safety of everyone;
- Caring for the safety of each other; and
- Stopping work anytime unsafe conditions or behaviors are observed until the job can be completed safely.

SCE strives to achieve the continuous commitment and dedication by all workers to follow these values to assure that the safest workplace is established and that the safest work behaviors are always used to prevent hazardous conditions and injuries. SCE trains all workers, as applicable, on using a variety of human performance and safety awareness tools. Among other areas of the company, these tools are deployed at SONGS and include: (1) completing meticulous pre-job planning, pre-job briefs, and safety observations during work; and (2) requiring appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. SCE insists upon their use, and monitors adherence through a variety of human-performance / safety metrics. Every worker is also authorized to stop work and obtain clarification any time a question arises regarding the safe performance of any job.

SCE has instituted several oversight mechanisms to help ensure that work proceeds safely at SONGS, and to monitor and report on safety performance. SCE uses a focused, risk-based observation program through which qualified safety inspectors personally observe the performance of spent fuel transfer[6] and decommissioning activities and provide real-time safety recommendations as needed. The SONGS Safety group continually monitors safety performance, including near-misses and other lessons learned, and provides frequent safety

[6] See Section IV.B for further discussion regarding the risks during spent fuel transfer activities.

reports to the SONGS Chief Nuclear Officer and senior leadership team. SONGS safety performance is also reviewed by the Nuclear Oversight Board, an independent team of nuclear industry executives that provide objective input to SONGS leaders regarding all aspects of nuclear facility operations including safety. SONGS also employs a corrective action program that performs in-depth evaluations of all plant incidents or accidents.

B. Decommissioning General Contractor (DGC) Safety Program

In December 2016, the Participants retained SONGS Decommissioning*Solutions* (SDS), a consortium of Energy*Solutions* and AECOM, as the Decommissioning General Contractor (DGC) to perform a substantial portion of the SONGS decommissioning work scope.

SDS staff has substantial experience and expertise in performing large-scale nuclear decommissioning projects similar to SONGS. SDS commenced mobilizing its SONGS decommissioning team in 2017, and has assumed the performance of many plant functions that were previously performed by SCE. SDS will commence physical decontamination and dismantlement activities at SONGS upon authorization from the California Coastal Commission (CCC) when it issues the Coastal Development Permit (CDP) required for major decommissioning activities.

Like SCE, SDS implements a comprehensive nuclear and industrial safety program that meets all NRC and other regulatory requirements. All other contractors are also required to implement robust and comprehensive safety programs associated with their work on the SONGS decommissioning project.

C. SCE Oversight of Safety

SCE, as decommissioning agent on behalf of the other Participants, actively oversees the performance of all decommissioning activities, whether by utility personnel or its contractors. The purpose of SCE's oversight is to assure that: (1) each decommissioning work scope is performed safely and in accordance with site procedures; and (2) the site is restored to a radiologically safe condition suitable for future uses.

For example, if a work scope involves the demolition, removal, and disposal of a particular building and its foundations, SCE's oversight helps ensure that the building and foundations are removed safely and in their entirety. It also helps ensure that the disposal of all associated waste materials is performed completely and documented properly, in accordance with NRC and other regulatory requirements. Through its active oversight, SCE will stop decommissioning work if it is not being done safely in accordance with regulatory requirements.

As the decommissioning agent for the Participants, SCE is ultimately responsible for making sure that there are no remaining impediments to terminating the NRC licenses and the site leases and grants of easement after all decommissioning and final site restoration work is completed.

IV. DISCUSSION ON EXISTING RISKS

A. Risk – Operational (Spent Fuel Pool Operations)

1. Description of Risk

All fuel that remains in the Units 2 and 3 spent fuel pools are scheduled to be removed from the pools and transferred to the SONGS ISFSI. Until the fuel is removed, the spent fuel pools and all necessary equipment will continue to operate. The primary risk resulting from spent fuel pool operations is the potential for insufficient cooling to compromise the intended state of the spent fuel. This could result from circumstances such as a seismic event that causes damage to the spent fuel cooling system components, or a long-term power outage.

2. Mitigation of Risk

The primary function of the Operations group is to safely maintain spent nuclear fuel in the pools and the ISFSI. This includes operating, inspecting, and testing the remaining in-service plant equipment within the requirements of the NRC license, defueled technical specifications, and operating instructions. SONGS' NRC-certified fuel handlers keep the spent fuel pools operating properly, operate the plant systems that provide and support spent fuel pool cooling, and perform periodic testing to make sure the equipment continues to perform within design parameters.

The spent fuel pool meets NRC seismic design requirements, and the spent fuel cooling system consists of redundant, engineered components to help ensure that spent fuel cooling capability is maintained. In addition, SONGS has a back-up diesel generator to provide electric power in the event there is a power outage at the site. To further mitigate the risks associated with spent fuel pool operations, all utility workers and contractors, including the Operations group, adhere to the following:

- Use detailed engineered procedures for all spent fuel pool operations activities. Using these procedures helps ensure that work activities are performed and completed in a deliberate and predictable manner.
- Participate in a pre-job brief each day before a work activity commences. Here, each task is discussed in detail, and questions are answered to help ensure that everyone has a clear understanding of the process and expected outcomes.
- Review the current radiological safety requirements for the spent fuel pool area as a condition of entry into the area, wear dosimetry and protective clothing, and follow radiological safety procedures to keep exposure to radioactive materials as low as reasonably achievable.

- Use three-way communications (i.e., direction provided, acknowledgement and repeat-back of the direction, and final confirmation) throughout all stages of a work activity, and the phonetic alphabet when appropriate (e.g., saying "Bravo 1" instead of "B1"), to help avoid miscommunications.

All workers are authorized and encouraged to stop work and ask for clarification any time an uncertainty or unexpected result arises. All work activities are subject to NRC and SCE quality assurance oversight to provide independent assurance that they are performed safely and correctly in accordance with applicable procedures.

After all fuel is transferred out of the spent fuel pools, the risks associated with spent fuel pool operations will be permanently eliminated. The pools will then be drained, decontaminated, and decommissioned.

B. Risk – Fuel Transfer Operations (FTO)

1. Description of Risk

SCE retained Holtec International to design, license, and construct an expansion to the ISFSI and to transfer all remaining Units 2 and 3 fuel from wet storage in the spent fuel pools to dry storage in the ISFSI.

The fuel transfer process includes the following steps:

1. Load up to 37 fuel assemblies into a multi-purpose canister (MPC).
2. Insert the MPC into a shielded transfer cask (cask) and weld a shielded lid on the MPC.
3. Transfer the cask from the pool to the ISFSI via a specially-designed trailer.
4. Transfer the cask from the trailer to a vertical cask transporter (VCT) and lower the MPC out of the cask and into the ISFSI canister enclosure cavity (CEC).

The potential risks of FTO include the dropping of a fuel assembly in the spent fuel pool or an MPC; mishandling a cask while in transit to the ISFSI; or mishandling an MPC during transfer into a CEC.

2. Mitigation of Risk

Before commencing the transfer of fuel from the spent fuel pools to the ISFSI, SCE required that Holtec submit its fuel transfer plan and safety program for review and approval. Upon approval, Holtec performed a series of "dry run" cask loading and transfer simulations to demonstrate to SCE, and ultimately to the NRC, that it could accomplish the transfers safely and efficiently. These "dry runs" were performed in the presence of NRC inspectors; actual transfers could not commence until the NRC provided its approval.

Upon receiving NRC approval, Holtec commenced the FTO in one spent fuel pool with the intent to perform multiple transfers from that same pool before commencing fuel transfers from the other pool. Other safety mechanisms were incorporated to support FTO, such as the use of single failure-proof cranes[7] at the spent fuel pools and on the vertical cask transporters. This provides an additional level of assurance that fuel assemblies and MPCs/casks can be lifted safely within the fuel handling buildings and at the ISFSI with a substantially reduced risk of being dropped or mishandled.

To further mitigate the risks associated with fuel transfer operations, all utility and contract workers use detailed engineering procedures for all FTO activities. Use of these procedures helps ensure that work activities are performed and completed in a deliberate and predictable manner. As the part of the procedures, the workers:

- Participate in a pre-job brief each day before a work activity commences. At this pre-job brief, each task is discussed in detail and all questions are answered to help ensure that everyone has a clear understanding of the process and expected outcomes.
- Review the current radiological safety requirements for the spent fuel pool area as a condition of entry into the area, wear dosimetry and protective clothing, and follow radiological safety procedures to keep exposure to radioactive materials as low as reasonably achievable.
- Use three-way communications (i.e., direction provided, acknowledgement and repeat-back of the direction, and final confirmation) throughout all stages of a work activity, and the phonetic alphabet when appropriate, to help avoid miscommunications.

All workers are authorized and encouraged to stop work and ask for clarification any time an uncertainty or unexpected result arises. All work activities are subject to NRC and SCE quality assurance oversight to provide independent assurance that they are performed safely and correctly in accordance with applicable procedures.

After all fuel is transferred out of the spent fuel pools, the risks associated with FTO will be permanently eliminated. All spent fuel assemblies will have been sealed into dry storage canisters and placed in the passively-cooled, robustly-secured ISFSI.

3. Current Status of FTO

On August 3, 2018, during the final step of lowering a loaded canister into the ISFSI CEC, the canister became wedged in the CEC when the bottom of the canister got caught on an

[7] Single failure proof cranes are designed to prevent load drop during the occurrence of any single failure of the lifting system, providing the highest level of operational safety in the industry.

inner ring that helps guide the canister into place. There is a very snug fit in the CECs, and it is not unusual for it to take the downloading team a few manipulations to get the canister aligned appropriately. The crew performing this work did not initially recognize that the canister had become wedged on the inner ring. However, SCE's oversight team determined the canister was not sitting properly, and the canister was repositioned and safely placed on the bottom of the CEC. At no point during this event was there any harm to an employee or the public.

Adhering to the safety principles discussed above, SCE immediately stopped further FTO activities until it could fully investigate the event and determine appropriate actions to ensure the continued safety of employees and the public. SCE has directed its contractor, Holtec, to prepare a root cause evaluation (RCE), so that appropriate corrective actions could be determined and implemented. SCE is also preparing an apparent cause evaluation (ACE) to assess its oversight of Holtec's activities and determine how SCE's oversight may be enhanced. SCE will revise FTO procedures and conduct additional training as identified through the RCE/ACE. These efforts are consistent with SCE's ongoing efforts to continuously improve all work practices at SONGS.

SCE also notified the NRC regarding the event. In September, the NRC conducted a special investigation to review SCE's investigation, causal evaluations, and planned corrective actions. SCE will not resume FTO activities until SCE is satisfied that all appropriate corrective actions have been taken, and the NRC has completed its on-site inspection activities and indicated that it is satisfied with SCE's actions. SCE remains committed to safety and a rigorous oversight process during decommissioning.

C. Risk – ISFSI Operations

1. Description of Risk

The ISFSI consists of reinforced concrete structures designed to support and shield MPCs while providing passive heat removal for long-term storage of used nuclear fuel, until the U.S. Department of Energy accepts the used fuel for disposal. The passive cooling capability relies on cool air to flow into the enclosure and the release of warm air to flow out of the enclosure. The risk of ISFSI operations is that the air flow into and out of the ISFSI could become compromised due to the presence of debris in the air inlets and/or outlets, potentially leading to an overheating of the material inside.

2. Mitigation of Risk

The ISFSI and all components are licensed by the NRC. The SONGS ISFSI is engineered to help ensure sufficient passive air-cooling capability in accordance with NRC standards for heat transfer. All air inlets and outlets are sized to provide proper air-cooling capability, and have grating installed to prevent wildlife nesting.

SONGS personnel are assigned to walk down the ISFSI at least once daily, and visually inspect all enclosure gratings for the presence of any material that could impair air flow. Any findings are promptly reported so that the materials, if any, are removed as soon as possible. Thermal detectors and radiation monitors are also installed and continuously monitored by the Operations group. Any unexpected temperature increase or increase in radioactivity would be investigated immediately.

The risks associated with ISFSI operations will continue to be present until all spent fuel is transferred from the ISFSI to a federally licensed offsite disposal facility. This is currently assumed to occur by 2049.

D. Risk – Security

1. Description of Risk

As long as nuclear fuel continues to remain on-site, and in accordance with NRC regulations (10 C.F.R. § 73.1 and 10 C.F.R. § 50.54), SONGS must maintain a security force to protect against radiological sabotage. Currently, spent fuel is maintained in wet storage in the Units 2 and 3 spent fuel pools and in dry storage in the ISFSI. Thus, the security requirements apply to both locations. Security requirements for the fuel in the spent fuel pools apply not only to the pools themselves, but also to all of the plant systems that are required to operate the pools. The security risks at SONGS will be substantially reduced after all spent fuel has been transferred to the ISFSI because there is a smaller footprint to protect and the ISFSI is a passive system (i.e. no other equipment requires security protection).

2. Mitigation of Risk

As required by NRC regulations, the physical security of the licensed special nuclear material (nuclear fuel) is protected by the SONGS Security force, and by the concentric areas of graduated security features at the plant site.

The SONGS Security force is comprised of highly-skilled officers who must qualify and maintain applicable NRC security qualification standards. To maintain their capability to detect and deter threats, SONGS Security officers participate in ongoing training exercises that include firearm range qualifications, force on force drills, etc.

SONGS Security personnel monitor the plant boundaries pursuant to SCE's license and NRC's requirements. There are three security boundaries at SONGS. The first is the plant boundary, which is the perimeter fence that provides the outermost level of protection. Inside the plant boundary is the Owner Controlled Area (OCA), which is subject to an increased level of protection. All workers and visitors to the OCA must have been authorized in advance by SONGS Security, and must continually display a SONGS-issued photo identification badge.

The third and highest level of protection is the Protected Area (PA). This level of protection is necessary due to the radiological materials located within this boundary. This boundary is surrounded by substantial physical barriers and state-of-the art intrusion detection systems, and is continually monitored by the armed SONGS Security force. All personnel and equipment access to the PA is controlled by the following activities: (1) personnel who have unescorted access to the PA are subject to increased initial and ongoing screening requirements, as well as to annual retraining requirements; and (2) all vehicles and equipment are searched by SONGS Security officers before they are allowed to enter the PA. This multi-faceted approach to security provides an effective level of assurance against the security risks that may be encountered at SONGS.

There are currently two PA's at SONGS, one that includes the spent fuel pools and one that includes the ISFSI. After all spent fuel is removed from the spent fuel pools, the PA that includes the spent fuel pools will be no longer be needed. The ISFSI PA will remain in place until all spent fuel is removed, which is currently scheduled to occur by 2049.

E. Risk – Industrial Safety

1. Description of Risk

As a large industrial facility that uses heavy equipment, energized electrical circuits, pressurized fluid systems, and hazardous chemicals, various industrial safety risks associated with these activities and materials exist at SONGS. It is imperative, therefore, that all work activities at SONGS are performed safely to avoid industrial accidents and injuries, electrical shock, and chemical exposures.

2. Mitigation of Risk

As discussed above, SCE, as the decommissioning agent, and all contractors who perform work at SONGS, are required to implement robust safety programs that meet or exceed federal and state requirements. These programs emphasize a safety-first culture and employ meticulous planning, pre-job briefs, appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. The programs are also designed to maintain workers' exposure to radiation as low as reasonably achievable.

As relevant safety lessons are learned, they are disseminated through electric and nuclear industry organizations, to peer facilities so that each facility can benefit from and leverage each other's experiences. When SCE receives such notices concerning other facilities, the notices and information are shared with onsite contractors. In addition, briefings are conducted to disseminate the information to workers to help reinforce good safety practices and avoid or eliminate unsafe behaviors. Finally, before any major decommissioning activity is performed at SONGS, the performance of such activity at other facilities is reviewed to identify additional insights and perspectives into how the activity may be performed more safely and efficiently at SONGS.

V. CONCLUSION

The decommissioning of SONGS is a major activity that will be performed by SCE and its contractors over a period of many years. Nuclear decommissioning projects involve both radiological safety aspects that are regulated exclusively by the federal government, and industrial safety aspects that are subject to both federal and state regulation. Various decommissioning and spent fuel storage activities will be performed until the project is completed, which is expected in 2051.

The spent fuel pool operations and fuel transfer operations represent the two most significant risk exposures of the SONGS decommissioning project. However, after these activities are completed, these risks will be permanently eliminated. The spent fuel pools will be drained, decontaminated, and decommissioned, and all spent fuel assemblies will have been sealed into dry storage canisters in the passively-cooled, robustly-secured ISFSI to await future shipment to an offsite disposal facility.

Safety is paramount to SCE. To help ensure that SONGS decommissioning activities are safely performed by both SCE and its contractors, SCE has identified and analyzed numerous risks associated with the SONGS decommissioning project and established a robust safety program that adheres to NRC radiological safety regulations and federal and state industrial safety regulations. SCE also insists that all contractors performing SONGS decommissioning activities have similarly robust and compliant safety programs. As the decommissioning agent ultimately responsible for decommissioning safety, SCE will continue to provide thorough oversight of all utility- and contractor-performed decommissioning activities throughout the duration of the project.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix B
Transmission & Substation Assets

Rosemead CA
November 15, 2018

Contents

Tables

Figures

I. Executive Summary

A. Overview

Southern California Edison (SCE) owns and maintains transmission lines, sub-transmission lines, and substation assets. These assets are essential to moving power over long distances, to maintaining grid reliability, and to serving the energy demands of our customer base.

This appendix explores the potential direct[1] safety risks associated with transmission lines, sub-transmission lines, and substation assets that are not addressed within SCE's nine top safety risks. The safety impact of the risk associated with these assets did not rise to the level of inclusion as a top safety risk within our RAMP report. However, SCE received interest from stakeholders[2] during pre-filing briefings to better understand the potential safety-related risks of these assets. Accordingly, SCE summarizes in this Appendix how these assets can potentially create safety risks.[3]

B. Scope of Appendix

Table I-1 SCE details the scope of this Appendix.

[1] Direct safety impacts are first-order consequences of risk events that directly result in an injury or fatality.

[2] Both the Commission's Safety Enforcement Division (SED), and Office of the Safety Advocate (OSA) expressed interest in transmission and substation level safety risks, whether they create direct or indirect safety impacts.

[3] This Appendix does not provide a bowtie or any quantitative analysis of the potential risks, as is provided in the nine RAMP risk chapters.

Table I-1 - Appendix Scope

In Scope	• Risks associated with transmission, sub-transmission, or substation assets not covered in the nine RAMP risk chapters. These include risks associated with, but excluded from the scope of, the following RAMP chapters: Contact with Energized Equipment, Wildfire, and Underground Equipment Failure.[4] • Qualitative evaluation of examples of safety risks associated with transmission, sub-transmission, and substation assets.
Out of Scope	• Risks associated with transmission, sub-transmission, or substation assets that are addressed in the other six RAMP risk chapters (i.e. impacts related to Building Safety; Cyberattack; Employee, Contractor & Public Safety; Hydro Asset Safety; Physical Security; Climate Change). These chapters do not exclude these assets. • Indirect, or second-order, safety impacts resulting from widespread electric service interruptions.[5] • Quantitative and comprehensive evaluation of safety risks associated with transmission, sub-transmission, or substation assets, using risk bowtie structure and RAMP model analysis.

C. Types of Risks Evaluated in this Appendix

There are two general types of direct safety risks related to transmission lines, sub-transmission lines, and substation assets: (1) Contact with energized equipment, where a person makes contact with the system while the system is intact and operating normally; and, (2) Equipment and/or structure failure where a person is injured as a result of asset failure. In

[4] The Contact with Energized Equipment and Wildfire chapters focus on distribution-level overhead conductor. The Underground Equipment Failure chapter also focused on distribution-level equipment.

[5] Widespread electric service interruptions have obvious direct *reliability* consequences. However, they do not typically have direct *safety* consequences. This is the primary reason why this risk was not included as one of SCE's RAMP risks (In this RAMP report, SCE does not address the indirect, second-order safety impacts from risk events). Widespread electric service interruptions can potentially cause loss or disruption of other services that, in turn, can be contributing factors to serious injuries or fatalities. The elevated potential for indirect safety impacts from such widespread interruptions is one of the items that distinguishes safety risks associated with transmission and sub-transmission facilities from the safety risks associated with distribution facilities. At the transmission level, the relationship between reliability performance and secondary safety impacts means that the consequences can be more widespread than at the distribution level. However, for reasons stated in Chapter 1 - RAMP Overview, we do not attempt to evaluate those indirect impacts in this RAMP report, including within this Appendix.

this Appendix, SCE provides examples of potential safety risks associated with these assets, including:[6]

- Transmission Line Clearances;
- Transmission Conductor and/or Conductor Attachment Failure;
- Transmission Line Structure Failure;
- Substation Transformer Failure; and
- Substation Circuit Breaker Failure.

[6] This should be considered a list of examples, and not an exhaustive list of safety risks associated with transmission and sub-transmission lines and substations assets.

II. Description of SCE's Electric System

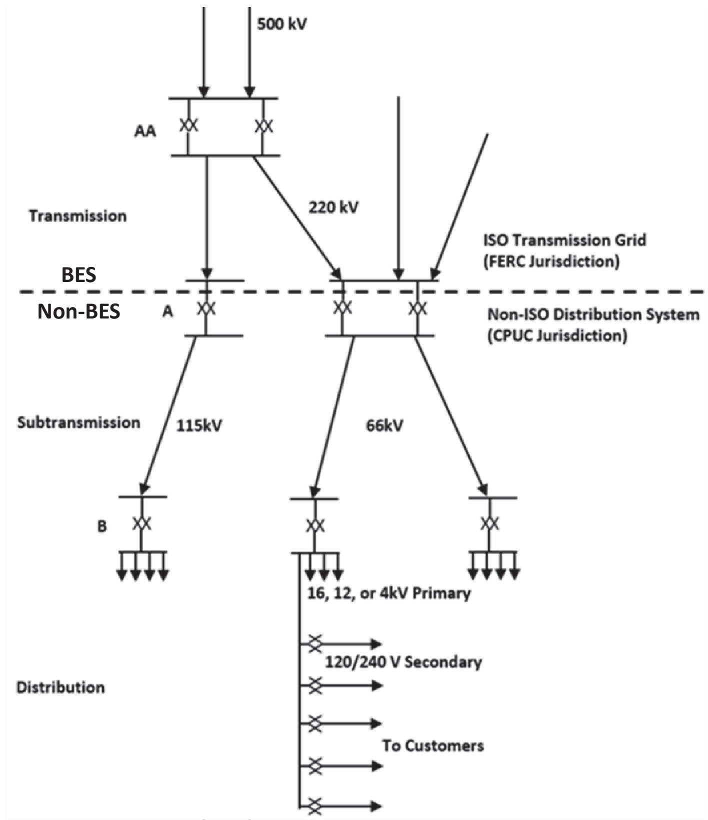
The Bulk Electric System (BES) consists of electric facilities and control systems necessary for operating an interconnected electric transmission network. In general, SCE's portion of the BES includes all transmission lines operating at 220 kV or higher and all substation facilities operating at 220 kV or higher. These facilities fall under Federal Energy Regulatory Commission (FERC) jurisdiction, are subject to NERC Reliability Standards,[7] and are under the operational control of the California Independent System Operator (CAISO).

The system of facilities used in the local distribution of electric energy are referred to as "local distribution" facilities and are not part of the BES. In general, SCE's local distribution facilities include sub-transmission lines typically operating at 66 kV or 115 kV, substation facilities typically operating at 66 kV or 115 kV, and distribution lines and substation facilities operating at voltages below 66 kV.[8] SCE's non-BES facilities are under California Public Utilities Commission (CPUC) jurisdiction and SCE operational control. A simplified overview of SCE's electric system, showing the distinction between BES and non-BES facilities, is shown in Figure II-1 below.

[7] The U.S. Energy Policy Act (EPA) of 2005 authorized the creation of an Electric Reliability Organization (ERO). The EPA of 2005 was triggered in part by concerns generated by the August 2003 blackout that affected 40 million people in the mid-western and northeastern United States and 10 million people in eastern Canada. On July 20, 2006, the Federal Energy Regulatory Commission (FERC) issued an order in Docket No. RR06-1-000 certifying the North American Electric Reliability Corporation (NERC) as the nation's Electric Reliability Organization (ERO) under Section 215 of the Federal Power Act. As the ERO, NERC has been granted the authority to develop and enforce reliability standards applicable to all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance.

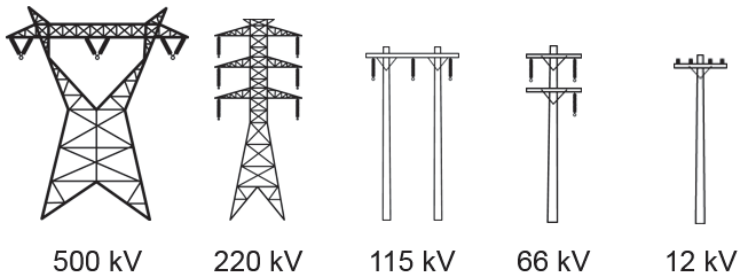
[8] SCE does have some sub-transmission lines and substation assets below 220 kV that are also BES facilities. These are the exception rather than the rule; the vast majority of SCE's sub-transmission system is classified as non-BES.

Figure II-1 – SCE's Electric System (BES and non-BES facilities)



During the 20th century, the use of higher voltages for transmission became the industry standard. Higher operating voltages require lower levels of current for similar levels of power transfer. Higher transmission voltages are accommodated through transmission tower designs that include taller towers, longer insulators, and greater phase spacing. In turn, higher voltages accommodate longer lines by means to lower losses, less voltage drop, and greater power transfer capabilities. Figure II-2 below illustrates the differences in construction, approximate effective range, and approximate nominal capacity in MW of typical transmission lines (500 kV and 220 kV), sub-transmission lines (115 kV and 66 kV), and distribution lines (12 kV and other distribution voltages).

Figure II-2 – Comparison of Transmission, Sub-transmission and Distribution Lines



Effective Range	Several Hundred Miles	Hundred Miles	Fifty Miles	Twenty Miles	Three Miles
Nominal Capacity	2,400 MW	650 MW	200 MW	120 MW	10 MW

The larger geographic reach of transmission lines is further extended through using BES substations that connect transmission lines together. Substations provide the capabilities of both switching and voltage transformation. In other words, substations link transmission lines to other transmission lines, and also link high voltage transmission lines to lower voltage sub-transmission lines. The interconnectivity that substations make possible tends to extend the wide area geographic reach of transmission lines, sub-transmission lines, and BES substation assets.

III. Examples of Transmission, Sub-transmission, and Substation Safety Risks

In this Appendix, SCE provides examples of safety risks that can result from contact with energized equipment, or equipment/structure failure, in the context of transmission, sub-transmission, and substation assets. We also summarize at a high level the existing controls and mitigations to manage these risks.

A. Transmission Line Clearances

1. Risk Description

This represents transmission line or sub-transmission line discrepancies leading to General Order (GO) 95 clearance violations. This is an example of contact with energized equipment risk type.

A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak load conditions. Discrepancies have been prioritized based on criteria, such as line sag when operating at our below 130 degrees Fahrenheit, and potential risk to public safety and reliability. Safety risks associated with inadequate vertical clearances are elevated in locations that do not meet GO 95 clearance requirements, as high voltage transmission lines are more accessible for human contact.

2. Controls and Mitigations

Remediation work to resolve discrepancies includes replacing towers, poles and conductors, raising towers, clearing brush, replacing insulators, adding or lowering cross arms, removing slack, relocating lines, and other efforts. In 2015, SCE finalized a work plan to remediate discrepancies on CAISO lines by 2025 and on non-CAISO facilities by 2030. This work is performed through SCE's Transmission Line Rating Remediation program (TLRR).[9]

B. Transmission Conductor and/or Conductor Attachment Failure

1. Risk Description

This represents the failure of transmission line or sub-transmission line conductor and/or conductor attachments, which can lead to public injuries/fatalities. This is an example of equipment and/or structure failure risk type.

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[9] See A.16-09-001, SCE's Test Year 2018 General Rate Case, Exhibit SCE-02, Volume 7 for more discussion on SCE's TLRR program.

As transmission and sub-transmission conductors, splices, insulators, and associated hardware age, they have an increased risk of failing. Aging conductor is vulnerable to the stresses caused by circuit relays and other environmental factors. This may result in a failure and can cause conductor to fall to the ground, leading to potential wildfires, personal property damage, or third-party personal contact. These failures can also impact the integrity of the BES system, as well as the reliability of service to our customers.

2. Controls and Mitigations

To mitigate aging conductor and conductor attachment risks, SCE replaces aging infrastructure on an annual basis within the Transmission Infrastructure Replacement program.[10] Replacements are prioritized based on age, wire size, deterioration identified via inspections, and documented interruptions.

C. Transmission Line Structure Failure

1. Risk Description

This represents the failure of transmission line or sub-transmission line structures, which can lead to public injuries/fatalities. This is an example of equipment and/or structure failure risk type.

Aging lattice steel structures and similar structures are at risk of failing due to corrosion, especially in coastal regions subject to marine layer or moisture source. This can have both a direct safety risk to our workers and members of the public, as well as impact the reliability of our service to customers.

2. Controls and Mitigations

SCE is presently developing a plan to identify transmission line and sub-transmission line structures that pose the greatest risk of failing. SCE is also evaluating a range of mitigation options to address these structures, such as applying a coating to prevent further corrosion, or replacing structures. SCE anticipates providing additional details as part of the upcoming 2021 GRC.

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[10] See A.16-09-001, Exhibit SCE-02, Volume 7, for a full description of SCE's Transmission Infrastructure Replacement program.

D. Substation Transformer Failure

1. Risk Description

This represents the catastrophic failure[11] of substation transformers, which can lead to public and/or worker injuries/fatalities, as well as impact BES system integrity and affect service reliability to our customers. This is an example of equipment and/or structure failure risk type.

Transformers are one of the most critical pieces of equipment in a substation. Transformers are used to lower transmission voltages down to sub-transmission voltages and sub-transmission voltages down to distribution voltages, where a majority of customers draw their power. When a transformer fails, it may disturb the power flow to the system, causing a reliability consequence. In some cases, a transformer failure can be catastrophic in nature. If there are personnel near the transformer when a catastrophic failure occurs, those individuals are exposed to greater safety risks. In addition, catastrophic transformer failures can also damage other substation equipment and may cause widespread electrical service interruptions.

2. Controls and Mitigations

SCE has multiple programs to mitigate transformer failure related risks. These SCE maintenance and inspection programs monitor and maintain the condition of transformers.[12] The Substation Infrastructure Replacement (SIR) program[13] replaces aging transformers preemptively before they reach their end of usable lives. These mitigations are intended to reduce the number of transformer failures, which reduces the associated direct safety risks.

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[11] Generally speaking, SCE uses the term “catastrophic” to mean a sudden and complete failure of a piece of electrical equipment associated with an uncontrolled release of energy.

[12] See A.16-09-001, Exhibit SCE-02, Volume 6, for more details on SCE’s substation maintenance and inspection programs.

[13] See A.16-09-001, Exhibit SCE-02, Volume 8, for more details on SCE’s Substation Infrastructure Replacement program.

E. Substation Circuit Breaker Failure

1. Risk Description

This represents the catastrophic failure of substation circuit breakers, which can lead to public and/or worker injuries/fatalities. This is an example of equipment and/or structure failure risk type.

Substation circuit breakers are protective devices that primarily function to interrupt current flow when a fault condition occurs. This prevents damage to equipment and minimizes the impact of disturbances on the system, which can under certain circumstances lead to safety impacts.[14] Circuit breakers also provide a means to carry out routine switching operations in order to perform maintenance on substation equipment. There are two potential failure modes for circuit breakers that can result in potential safety impacts:

- Failure of circuit breaker to operate during fault event; and
- Catastrophic failure of circuit breaker during fault event.

The failure of a circuit breaker to operate during a fault could result in longer fault durations or inadequate fault clearing. This can result in greater damage to equipment and elevated safety risks. If a circuit breaker fails catastrophically, it could also expose nearby personnel to additional safety risks. A failing circuit breaker can make it necessary to use backup protection devices to clear faults. This increases the resulting size of electrical service interruptions and associated indirect safety risks.

Some circuit breakers are identified as potentially being subjected to more fault duty than they are rated for during a fault condition. These are referred to as overstressed circuit breakers. Circuit breakers identified as overstressed are more vulnerable to the failure modes described above.

2. Controls and Mitigations

SCE has multiple programs to mitigate risks related to circuit breaker failures. Our maintenance and inspection programs monitor and maintain circuit breakers conditions. The SIR program replaces aging circuit breakers preemptively before they reach the end of their

[14] Failures of protective relays can similarly lead to safety impacts. SCE includes replacing protective relays as part of our infrastructure replacement program.

usable lives. The Substation Equipment Replacement Program (SERP) replaces overstressed[15] circuit breakers. These mitigations are intended to reduce the number of circuit breaker failures, which in turn reduces the associated reliability and safety risks.

[15] Overstressed circuit breakers can be potentially subjected to more fault duty than they are rated for during a fault condition. Circuit breakers identified as overstressed are more vulnerable to the two failure modes described above.

SOUTHERN CALIFORNIA EDISON

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix C
Seismic Events

Rosemead CA
November 15, 2018

Contents

I. Introduction

Because we are located in southern California, seismic events are a key safety risk for SCE. While major seismic events occur infrequently, such events can seriously impact our critical assets and facilities. SCE must proactively harden our critical assets and facilities to mitigate the safety, reliability, and financial consequences of these events.

As discussed in Chapter I – RAMP Overview, SCE chose to address seismic event risk in this RAMP report as a risk driver, instead of as a discrete risk event. This approach better aligns with the risk bowtie structure SCE employs throughout this report. Accordingly, we include seismic events as a key risk driver in the Hydro Asset Safety and Building Safety chapters.[1]

Because of the importance of mitigating the impacts of seismic events on our critical assets and facilities, SCE provides additional detail on our Seismic Assessment & Mitigation Program in this Appendix.

[1] Because this RAMP report focuses on safety risks, we do not address in the RAMP risk chapters the considerable efforts that SCE undertakes to mitigate reliability risks associated with seismic activity.

II. Seismic Activity in Southern California

SCE operates in one of the most seismically active areas in the United States. SCE must plan for a major earthquake, as it represents one of the most catastrophic and widespread incidents that could occur in California. In a 2015 report, the United States Geological Survey (USGS) introduced its latest earthquake model, the third Uniform California Earthquake Rupture Forecast (UCERF3).[2] The UCERF3 model shows a higher prediction rate for earthquakes in Southern California, with magnitudes between 5.0 and 8.0, compared to what prior earthquake models included.

According to the USGS report, the increased threat is due to the many interconnected faults in California. These interconnected faults can trigger seismic activities in one another. This increases the probability of multi-fault ruptures. The probability is significant due to the number of faults interconnected with the San Andreas Fault, which runs through nearly all of the state and is most likely to be the source of the most catastrophic earthquakes in California. The report estimates that there is a 93 percent chance Southern California will experience one or more earthquakes of magnitude 6.7 (the magnitude of the 1994 Northridge earthquake) or greater in the next 30 years. Additionally, there is an estimated 36 percent chance of an earthquake of magnitude 7.5 or greater in the next 30 years, which would be the largest earthquake experienced by Southern California since the 1857 Fort Tejon earthquake. These predictions drive SCE's focus on preparing for and mitigating the potential impacts of moderate to large-scale earthquakes.

Table II-1 – USGS Prediction of Southern California Seismicity

Magnitude (Greater than or equal to)	Average Repeat Time (years)	Likelihood of one or more events in 30 years
6.0	2.3	100%
6.7	12	93%
7.5	87	36%
8.0	522	7%

[2] "UCERF3: A New Earthquake Forecast for California's Complex Fault System." US Geological Survey Fact Sheet 2015-3009.

III. Risk of Seismic Activity to SCE Environment

SCE maintains approximately 1,300 buildings that cover more than 7.3 million square feet. These buildings include 89 buildings supporting administrative functions, 128 buildings supporting service centers and warehouses, 8 buildings supporting critical facilities and data centers, and 1,088 buildings supporting substation and generation facilities. In addition, SCE maintains over 13,000 circuit miles of transmission lines, over 4,600 distribution circuits, and hundreds of thousands of substation and distribution transformers, circuit breakers, underground structures, etc. Lastly, SCE owns and operates numerous electric generating facilities, including peakers, baseload, and hydroelectric stations and dams. This infrastructure system is widely dispersed, complex, and interdependent.

A major earthquake can have a direct impact on this infrastructure, and also extend beyond safety concerns and physical damage to infrastructure and buildings. Those impacts also affect the resiliency of the Company as a whole by disrupting our workforce and damaging or disabling the infrastructure we rely on to deliver electricity to our customers.

Major earthquakes can profoundly impact safety, service reliability, and community resiliency. The 1994 Northridge earthquake was a significant milestone in the evolution of earthquake codes and standards. Seventy-eight percent of SCE non-electric facilities (such as occupied buildings and warehouses) were built prior to that earthquake. As a general matter, it is expected that these buildings are more vulnerable to earthquakes than those built to modern codes and standards.

In addition, SCE owns and operates 28 high hazard dams – some dating back as far as the early 1900's. Due to potentially catastrophic safety and reliability impacts if a dam fails, these high hazard dams are subject to state and federal inspections, and undergo dam safety reviews by an independent consultant every five years. This is further discussed in Chapter 8 – Hydro Asset Safety.

A major seismic event can severely damage SCE's infrastructure and its ability to provide electric service. SCE's electric infrastructure includes transmission lines, towers, and substations, down to distribution substations, lines, poles, and equipment. Transmission lines and towers move high-voltage electricity from locales far from SCE's service territory. The lines and towers are typically built to withstand impacts from high wind, ice-wind combinations, and unbalanced longitudinal wire loads. Major seismic activity that causes deep-seated landslides, liquefaction,[3] lateral spreading, and ground shifting pose reliability risks to the transmission system – specifically, where towers and lines would be affected by such ground shifts associated with earthquakes.

Finally, electricity is critical when law enforcement, first responders, critical care providers, search and rescue teams, and relief organizations all respond to a major earthquake. SCE's ability to quickly restore power and continue operations following a major earthquake directly impacts how recovery progresses in the communities we serve. Restoring power after a disaster is a key indicator used by emergency managers to gauge when communities transition from response to recovery efforts.

[3] Liquefaction is a process by which water-saturated soil temporarily loses strength and behaves like a liquid. This effect can be caused by earthquake shaking and has resulted in severe damage to structures in past earthquakes around the world.

IV. SCE's Approach to Assessing and Mitigating Seismic Risk

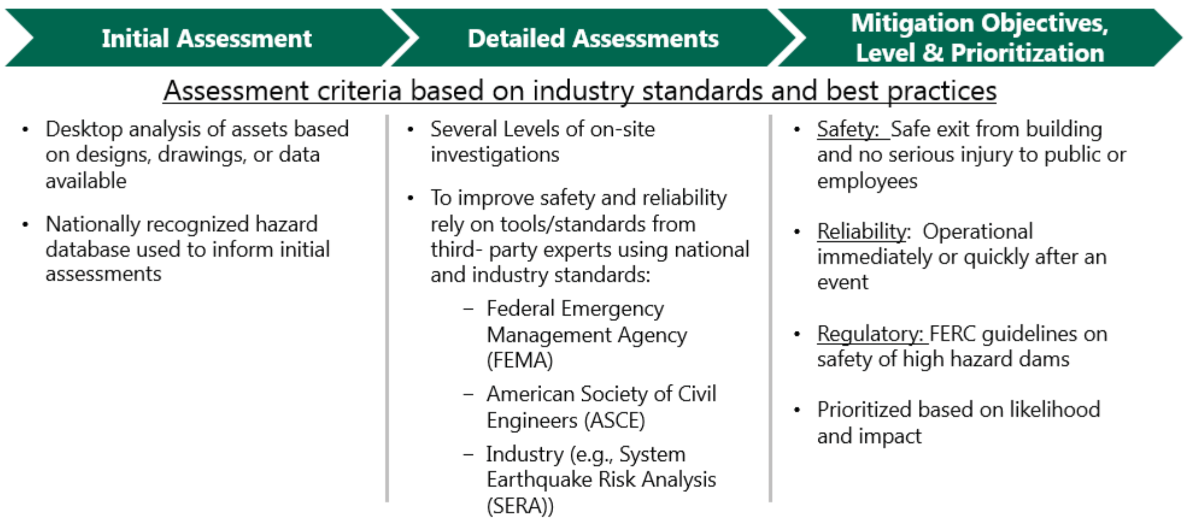
In 2016, SCE launched a company-wide Seismic Assessment and Mitigation Program to centralize and coordinate the company's ongoing seismic improvement projects for its infrastructure (electric and generation) and facilities (occupied and operational). In 2017, it added additional focus on IT and telecommunications capabilities. This centralized approach supports consistently applying best practices using recognized national standards when gathering and analyzing data, performing on-site assessments, identifying the technical and scientific subject experts, contracting with vendors, and compiling reports for the assessment and mitigation projects. Seismic mitigations are prioritized with a focus on keeping people safe and minimizing interruptions in electric service. A coordinated and company-wide seismic program is essential to help reduce the risk of a moderate or major earthquake causing substantial harm to workers, customers, and communities.

The Seismic Assessment and Mitigation Program is structured into four work streams, each of which follows a tiered and systematic approach for assessing and evaluating seismic risk and identifying and prioritizing mitigations by applying industry standards. The four workstreams are as follows:

- **Non-Electric Facilities** (Administrative and operational buildings and garages.);
- **Electric Infrastructure** (Transmission & distribution system – substations, towers, pole-mounted equipment, racks, etc.);
- **Generation Infrastructure** (Hydro, Powerhouses, Peakers, Mountainview Generating Stations);
- **IT / Telecommunications Infrastructure** (IT data centers, telecommunications sites and towers, sites housing critical IT systems).

The approach that SCE uses to assess the seismic impacts of the facilities and equipment in each of the four workstreams is illustrated in Figure IV-1.

Figure IV-1 – Risk Assessment & Mitigation Identification



A variety of standards are used to perform these assessments, including:

- **Federal Emergency Management Agency (FEMA) P-154:** Recommended methodology for Rapid Visual Screening techniques to identify, inventory, and screen buildings for potential seismic hazards;
- **American Society of Civil Engineers (ASCE) 41:** Industry standard. A three-tiered process applying the latest generation of performance-based seismic rehabilitation methodology to improve building performance in future earthquakes;
- **FEMA P-58:** Next-generation seismic performance assessment methodology that develops performance-based seismic design guidelines and stakeholder guidelines;
- **System Earthquake Risk Assessment (SERA):** Computer program used to identify seismic hazards on a system, utilizing historical performance data and estimated fragility values to calculate expected damage levels of electric equipment and infrastructure;
- **Institute of Electrical and Electronics Engineers (IEEE) IEEE-693:** Seismic design recommendations for substations including seismic criteria, qualification methods and levels, structural capacities, performance requirements for operating equipment, and installation methods;
- **Federal Energy Regulatory Commission (FERC) Division of Dam Safety and Inspections Engineering Guidelines:** Seismic guidelines for dam safety and hydropower projects

SCE's Seismic Assessment and Mitigation Program is currently focusing on the following efforts through 2020:

- **Electric** – Retrofitting transmission substations, distribution overhead equipment Racks, transmission tower assessments, and relay racks;
- **Non-electric** – Retrofitting older precast concrete tilt-up[4] and reinforced masonry buildings;
- **Generation** – Assessing high hazard dams, powerhouses, peaker plants, and Mountainview Generating station;
- **IT/Telecomm** – Assessing and retrofitting data centers and telecomm racks supporting critical applications and grid systems.

For seismic work beyond 2020, SCE will consider the following work activities for inclusion in our 2021 GRC:

- **Electric** – Retrofitting distribution substations, continuing to assess and mitigate transmission towers;
- **Non-electric** – Improving facilities that store critical electrical equipment and performing additional retrofits of buildings;
- **Generation** – Performing ongoing assessments of high hazard dams and conveyance systems; potentially retrofitting assessed facilities;
- **IT /Telecomm** – Continuing to assess IT infrastructure and reinforcing computer racks in SCE buildings.

[4] Precast concrete tilt-up buildings are built from concrete panels pre-constructed at a manufacturing facility. The panels are “tilted” into place and connected to a roof diaphragm. Roof-to-wall connections for older buildings constructed with this method have historically performed poorly in earthquakes, resulting in significant damage.

V. Seismic Events as Drivers to Multiple RAMP Risks

SCE includes seismic events as a driver in several risk chapters. Table II maps where the seismic risk is addressed in this RAMP report.

Table II – Seismic Drivers in RAMP Risk Chapters

Chapter	Description	Controls and Mitigations Proposed in Chapter
[Ch. 8] Hydro Asset Safety	Seismic event is modeled as a driver that can lead to uncontrolled and rapid release of water from SCE's hydroelectric generating assets, if they were to fail.	C1 – Seismic retrofit C6 – Instrumentation and communication improvements
[Ch. 4] Building Safety	Seismic events of magnitude 6.0 or greater are modeled as a driver to structural compromise of occupied SCE buildings.	C1 – Seismic assessment and mitigation program C2 – Facility emergency management plans M4 – Worker relocation M5 – Building Replacement