BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Investigation into the November 2018 Submission of Southern California Edison Risk Assessment and Mitigation Phase	I.18-11-006

<u>SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) AMENDMENT TO PORTIONS OF 2018 RISK ASSESSMENT AND MITIGATION PHASE REPORT</u>

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Dated: **March 14, 2019**

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Southern California Edison Company (SCE) respectfully submits this amendment to certain specific portions of its Risk Assessment Mitigation Phase (RAMP) report. SCE filed its RAMP on November 15, 2019. Approximately one and one-half months later, on December 26, 2018, SCE filed its Second Amended Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program (Amended GS&RP Testimony).[1] The Amended GS&RP Testimony included certain numerical changes.

For the sake of transparency, and to help ensure consistency across the GS&RP and RAMP proceedings, SCE is submitting amended versions of two chapters in its RAMP showing: (1) Wildfire, and (2) Contact With Energized Equipment. The amended versions simply incorporate the newer numbers as found in the Amended GS&RP application. Importantly, the newer numbers which SCE has incorporated into its amended RAMP chapters do not materially change SCE's RAMP showing as filed and served in November 2018. The amended RAMP chapters still contain the same mitigation measures. In the amended RAMP chapters, SCE still

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[1] The Amended Testimony was filed in A.18-09-002.

chooses the same plans of mitigation in the chapters, and does so for the same reasons as found in the original RAMP chapters.

For the Commission's and the Parties' reference, SCE is filing and serving redlined and clean versions of the amended chapters. Appendix A is the redlined version, and Appendix B is the clean text version. SCE is also providing certain amended workpapers. The amended workpapers can be viewed and/or downloaded from SCE's website by going to:

1. www.sce.com/applications
2. Click on "SCE 2018 RAMP"
3. Select workpapers titled "I.18-11-006 SCE 2018 RAMP Report Workpapers – Amendment"

A summary table showing the amended documents is included below.

For Chapter 10 – Wildfire:
• Amended Chapter – with redlines
• Amended Chapter - clean
• Amended Workpaper: WP Ch. 10 RAMP Mitigation Reduction Workpaper
• Updates made in red to tab 'M1'
• Amended Workpaper: WP Ch. 10 - Mitigation Effectiveness Workpaper
• Updates made in green in 'Mitigation Tables – Updated' tab
• Amended Workpaper: RAMP to GSRP Comparison Workpaper
• Updates made in red to pages 3, 4, and 5
• Amended Workpaper: WP CH. 10 – Baseline Risk Assessment Workpaper
• Updates made in red to tabs 2 through 5
Chapter 5 - Contact with Energized Equipment:
• Amended Chapter – with updated redlined tables
• Amended Chapter - clean
• Amended Workpaper: WP Ch. 5 - Control & Mitigation Risk Reduction Effectiveness
• Updates made in red to tab 'M5'
• Amended Workpaper: WP Ch. 5 - Mitigation Effectiveness Workpaper
• Updates to be made in green in 'Mitigation Tables – Updated' tab

Respectfully submitted,

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/s/

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March 14, 2019

Appendix A
Redlined Versions

(U 338-E)

Southern California Edison Company

Risk Assessment and Mitigation Phase

REDLINE VERSION
March 2019

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]

[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

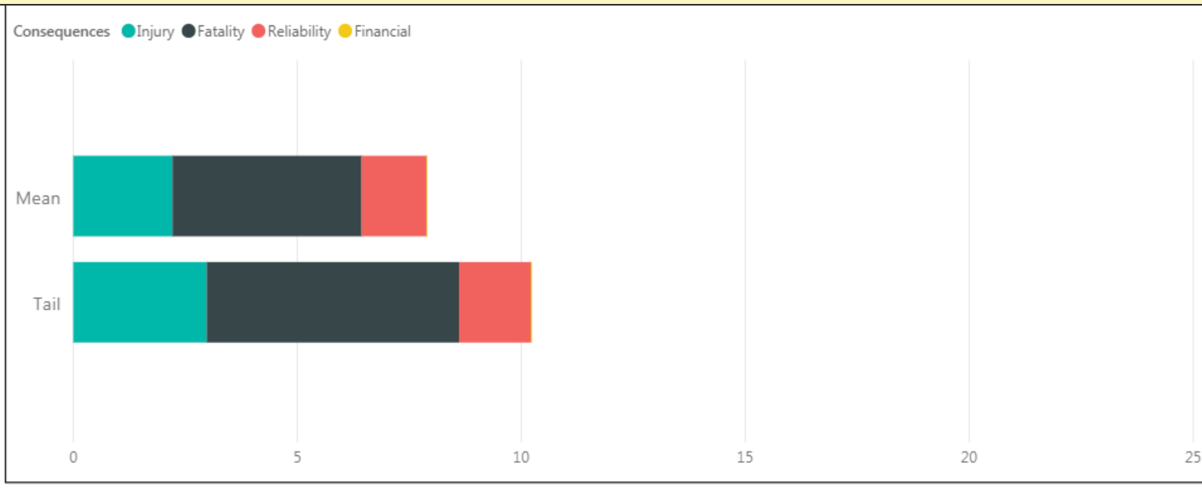
Figures represent 2018 - 2023 annual averages.

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	$345
	Baseline Risk	7.91	7.91	7.91
	Risk Reduction (MRR)	0.90	0.94	0.94
	Remaining Risk	7.01	6.97	6.97
	Risk Spend Efficiency (RSE)	0.0028	0.0028	0.0027
Tail Average (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	10.24	10.24	10.24
	Risk Reduction (MRR)	0.94	0.98	0.98
	Remaining Risk	9.30	9.26	9.26
	Risk Spend Efficiency (RSE)	0.0029	0.0029	0.0029
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.

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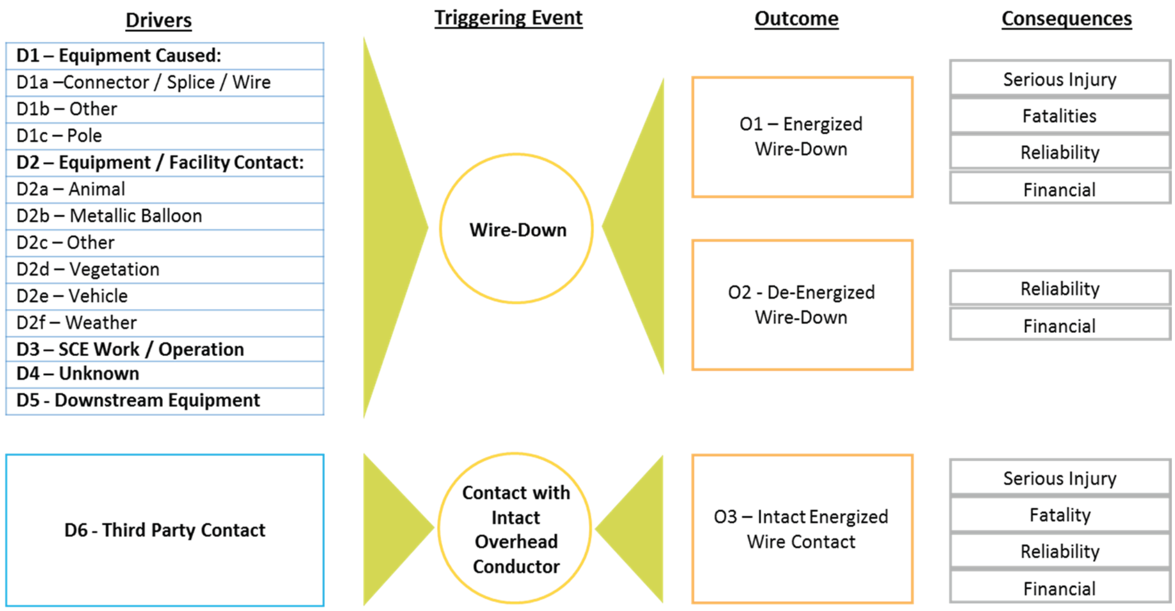
[7] *See* A.16-09-001, Exhibit SCE-02, Vol. 1, pp. 41-44.

[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.

Table II-1 – D1 (Equipment Cause) Frequencies

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%**

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.

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[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.

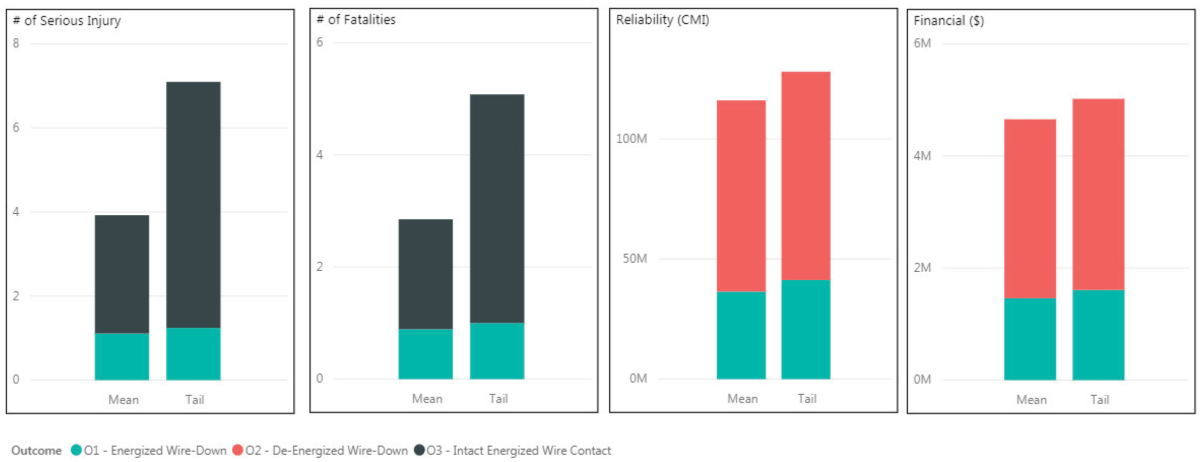
Figure II-3 – 2018 Outcome Likelihood[17]

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.

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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]

Outcome 3		**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.	N/A	N/A
Model Outputs *(Annual Average)*	NU - Mean	2.8	2.0	N/A	N/A
	NU - Tail Avg	5.9	4.1	N/A	N/A

[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

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[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

[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.

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[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

[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.

[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).

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[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	$ -	3.21	0.0045	3.36	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	0.3617	1.08	0.3785
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.60	0.0005	0.61	0.0005
			Total - Proposed Plan	$1,910	$36	5.37	0.0028	5.61	0.0029

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).

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	0.0140
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	2018	2023	$ 750	$ -	3.24	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	1.08	0.3788	1.14	0.3965
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.60	0.0005	0.61	0.0005
	Total - Alternative #1			$1,994	$36	5.64	0.0028	5.86	0.0029

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.

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	3.33	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	0.3596	1.08	0.3760
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.59	0.0005	0.60	0.0005
			Total - Alternative #2	**$2,034**	**$36**	**5.65**	**0.0027**	**5.90**	**0.0029**

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

REDLINE VERSION
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Wildfire

Chapter 10

Rosemead CA
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SOUTHERN CALIFORNIA EDISON
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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.[2]

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

[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] This includes amendments to SCE's GS&RP testimony filed on November 2, 2018 (SCE-01A-Amended) and December 26, 2018 (SCE-01A-Second Amended).

Out of Scope	Ignition associated with SCE Transmission/Substation Equipment,[3] Ignitions not associated with SCE.

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.

[3] 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 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.

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Table I-2 – Summary Results (Annual Average over 2018-2023)[4]

[4] 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.

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	$321	$837
	Baseline Risk	6.9	6.9	6.9
	Risk Reduction (MRR)	1.2	1.1	1.2
	Remaining Risk	5.7	5.8	5.7
	Risk Spend Efficiency (RSE)	0.0034	0.0033	0.0014
Tail Average (MARS)	*Cost Forecast ($ Million)*	$343	$321	$837
	Baseline Risk	24.0	24.0	24.0
	Risk Reduction (MRR)	4.0	3.7	4.0
	Remaining Risk	20.0	20.3	20.0
	Risk Spend Efficiency (RSE)	0.0117	0.0116	0.0048

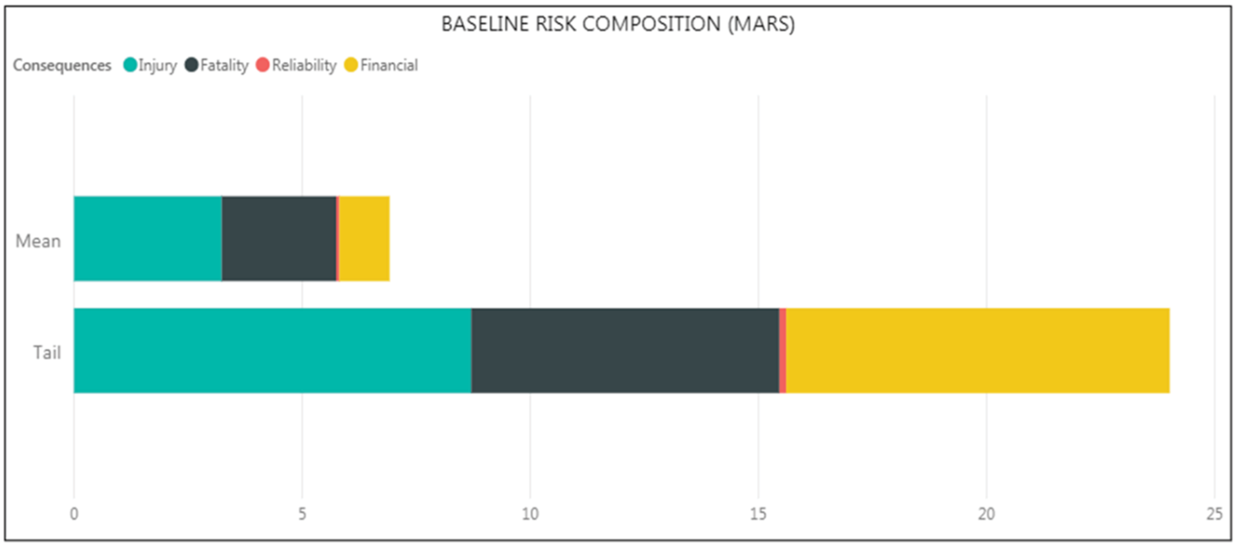
Figures represent 2018 - 2023 annual averages.

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.
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,[5] 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[6] in October 2017 was notable for the number of fatalities and the time of year. As we moved into 2018, the Mendocino Complex fire,[7] 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."[8, 9]

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[10] 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;[11] non-drought conditions are becoming shorter.

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[5] 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.

[6] 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.

[7] 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.

[8] 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.

[9] 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 .

[10] 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.

[11] 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."[12] 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.[13]

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.[14] 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

[12] Governor Brown's State of Emergency Proclamation, January 17, 2014, *available at* https://www.gov.ca.gov/2014/01/17/news18368/.

[13] See Chapter 12, Climate Change for more details.

[14] 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).*

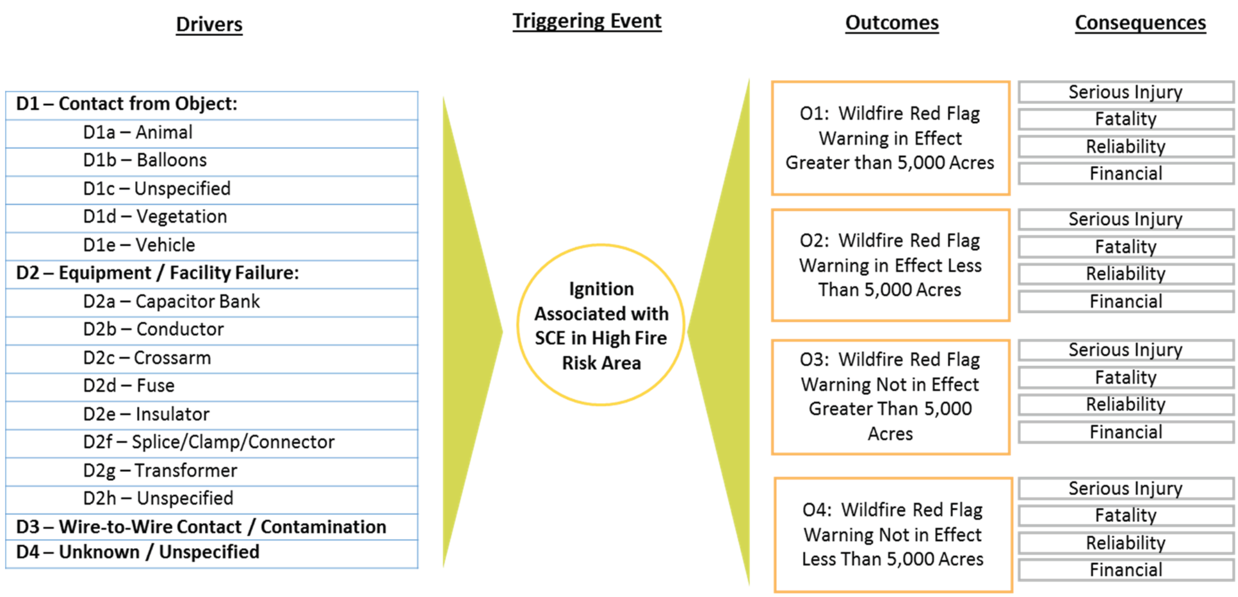
end 2020. This drives a difference in start and end dates for both filings, and necessarily causes the forecasts to vary.

- 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[15] 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.

[15] 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.[16] This analysis yielded four major categories of drivers:

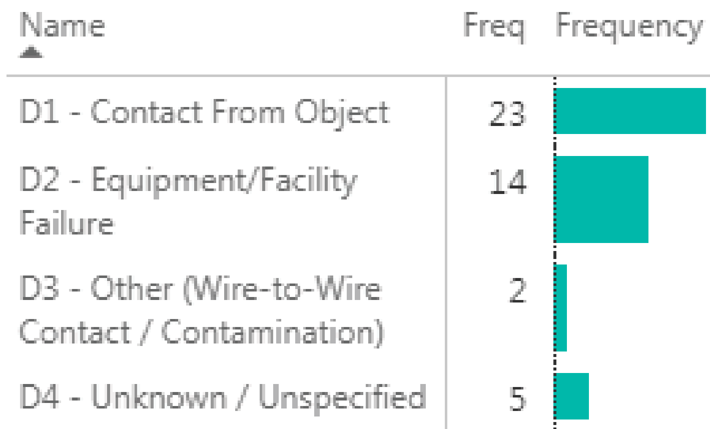
1. D1 - Contact From Object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/Facility Failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-Wire 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

[16] 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[17]



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.[18] Figure II-3 illustrates how the two most prevalent categories of faults can lead to wildfires.

[17] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

[18] 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

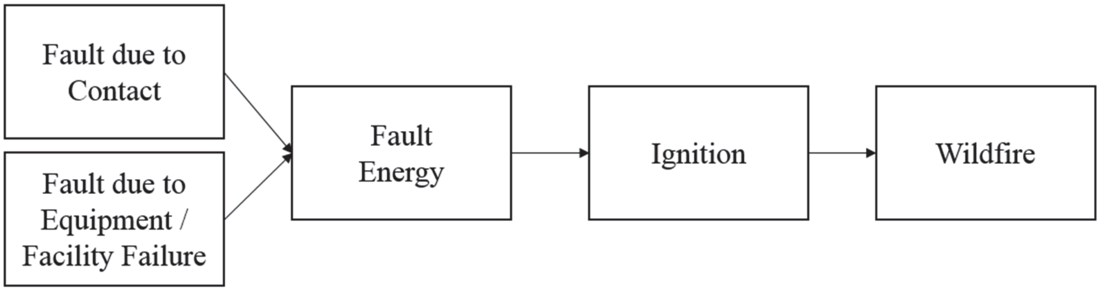


Table II-1 breaks down the different driver categories used within our risk modeling efforts. Table II-2 and Table II-3 break down the sub-drivers of Contact from Object and Equipment/Facility Failure, respectively.

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[19] 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[20] 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.

[19] Voltage potential is a measure of the propensity for electricity to travel from one point to another.
[20] 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.[21] 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

[21] 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.[22]

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.[23] 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.

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[22] 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

[23] 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[24]

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."[25]

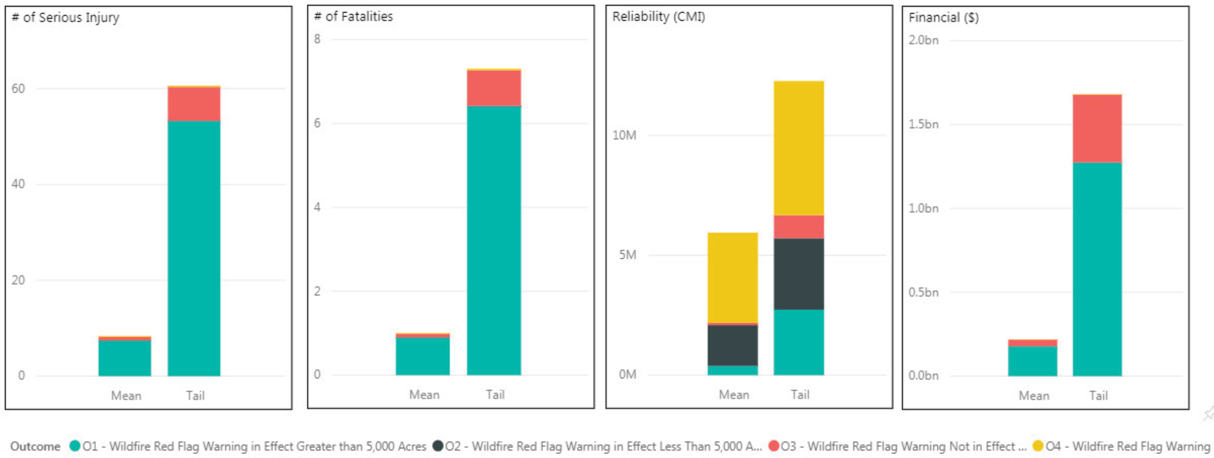
Please see Chapter 2 (Risk Model Overview) for additional detail regarding the outcome and consequence distribution modeling process. The sections that follow detail the data used to inform the development of these distributions.[26]

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.

[24] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[25] http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF
[26] 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.[27] 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

[27] 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[28,29]

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.

[28] 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.

[29] 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

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[30,31,32]

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.

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[30] 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.
[31] 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*).
[32] 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.[33]

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.[34]

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.

[33] Source: http://calfire.ca.gov/communications/downloads/newsreleases/2017/CAL%20FIREandU.S%20ForestAnnouce129MillionDeadTrees.pdf

[34] 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),[35] 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.[36] 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.

[35] See SCE's Test Year 2018 GRC, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

[36] 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,[37] and also impacts Driver D2 (Equipment Cause) for all years over the 2018-2023 RAMP period.[38] The OCP (C1a) impacts only Driver D2, for all years over the 2018-2023 RAMP period.[39]

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.[40] 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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[37] The specific sub-drivers impacted include D1a (Contact From Object – Animal), D1b (Contact From Object – Balloons), and D1d (Contact From Object – Vegetation).
[38] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[39] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[40] 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[41]

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[42] – 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

[41] 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*).

[42] 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.[43] 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[44] when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.[45] 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,[46] 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.[47] This approach lets SCE

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[43] 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.
[44] 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.
[45] 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."
[46] WCCP will have some safety and reliability benefits and OCP will have some wildfire benefits.
[47] 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~~5,500 circuit miles of bare overhead conductor in HFRA that appear to be best suited for reconductoring with covered conductor[48] 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 (1,369 circuit miles)**	**Contact From Object Scope (1,058 circuit miles)**
M1	Covered Conductor	Covered Conductor
M1a	Bare Conductor	Covered Conductor
M1b	Covered Conductor	Undergrounding

[48] SCE plans to complete deploying covered conductor for approximately ~~4,000~~5,500 circuit miles by ~~2025~~2026.

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

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.[49]

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.[50] 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

[49] 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).

[50] See https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

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, 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[51] 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

[51] 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.

fault interrupting capabilities with recloser blocking[52] and Fast Curve settings during Red Flag 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.[53] 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.

[52] 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 patrol can inspect for sources of the fault. After the patrol inspection occurs, the circuit may then be re-energized and electric service restored.

[53] 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.

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[54] to reduce the chances of fire ignitions during the most extreme and potentially dangerous fire conditions. A PSPS event represents the 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);

[54] In rare circumstances, extreme fire conditions could dictate that SCE may need to de-energize a circuit outside the HFRA.

- 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[55] 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).[56] 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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[55] 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.

[56] 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)[57] 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

[57] Specifically, M4 affects Sub-Driver D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

not dead or dying, SCE may still identify it as a potential risk to be mitigated by either removing 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.[58] The second sub-

[58] 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.[59] 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[60] – 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~~1,058 Bare Conductor ~~-~~– ~~945~~1,369	~~23,940~~22,474
M1b *(Covered + Underground)*	Covered Conductor – 1,369~~945~~	15,598~~11,060~~

[59] 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).

[60] 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[61] that the shield will increase fire resistance, enabling the pole to withstand an “extreme” wildfire.[62]

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.

[61] 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.

[62] *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.[63]

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.

[63] 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)[64]

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	$ -	0.09	0.0009	0.30	0.0030
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	1.64	0.0014*	5.28	0.0045*
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0311	3.35	0.1075
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.90	0.0892	6.66	0.3119
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1029	0.95	0.3321
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.23	0.0033
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.84	0.0149	3.19	0.0561
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$ 137	$ -	0.60	0.0044	2.26	0.0165
			Total	**$1,609**	**$447**	**7.02**	**0.0034**	**24.14**	**0.0117**

[64] 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.

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.

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[65] 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.

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).

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[65] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).

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~~ higher than the RSE of the Alternative Plan #1, and significantly higher than the RSE of Alternative Plan #2. ~~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~~.[66]

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 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.

[66] Please see Section V.A for a discussion of underrepresentation of long-term benefits for covered conductor.

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[67]
C1 and M1 *(Proposed Plan)*	$1,263	~~2.39~~1.73	1.37~~892~~E-03	2,680 circuit miles: ***M1:*** *2,426 Covered* ***C1:*** *65 Covered + 189 Bare* *0 underground*
C1a and M1a *(Alternative Plan #1)*	$1,160~~044~~	1.17~~.90~~	1.01~~820~~E-03	2,680 circuit miles: ***M1a:*** *~~1,481~~1,058 Covered + ~~945~~ 1,369 Bare* ***C1a:*** *254 Bare* *0 underground*
C1 and M1b *(Alternative Plan #2)*	$4,277~~5,501~~	2.08~~99~~	0.486~~365~~E-03	2,680 circuit miles ***M1b:*** *~~945~~ 1,369 Covered+ ~~1,481~~1,058 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).

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.

[67] 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.

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 45%~~60%~~ identical (each plan includes at least 189 miles of bare conductor and ~~1,481~~1,058 miles of covered conductor). Moreover, the variation in scope is less than ~~40%~~55% 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~~over 1,000 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.[68] The application then develops a mitigation-to-cost ratio for each conductor mitigation. It does not combine the different conductor mitigations.

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.[69]

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

[68] See page 52 of the GS&RP filing (A. 18-09-002).

[69] See Chapter 2 (Risk Model Overview) for additional detail regarding MARS, MRR and RSE.

GS&RP analysis parameters to RAMP modeling.[70] The workpaper takes the GS&RP analysis of bare conductor versus covered conductor, and runs an equivalent analysis using the RAMP model.[71] 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.

[70] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).
[71] 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)[72]

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	$ -	0.06	0.0006	0.19	0.0020
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0023
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	2018	2023	$ 1,062	$ -	1.11	0.0010	3.62	0.0034
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.98	0.0313	3.41	0.1095
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.92	0.0899	6.79	0.3178
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.30	0.1044	0.98	0.3426
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0011	1.28	0.0035
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0150	3.26	0.0574
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.77	0.0084
M9a	Fire Resistant Poles (M1a Scope)	2018	2023	$ 112	$ -	0.51	0.0045	1.93	0.0173
			Total	$1,480	$447	6.40	0.0033	22.41	0.0116

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

[72] 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.

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.[73] This was a key factor in our decision not to select Alternative Plan #1.

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.

[73] Please see Section V.C for additional detail.

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	$ -	0.09	0.0009	0.30	0.0030
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1b	Underground Conversion	2018	2023	$ 4,175	$ -	1.99	0.0005	6.38	0.0015
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0313	3.33	0.1070
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.92	0.0898	6.63	0.3103
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1029	0.95	0.3316
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0010	1.24	0.0034
M6	Microgrids	2021	2023	$ 10	$ -	0.00	0.0000	0.00	0.0000
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0150	3.21	0.0565
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9b	Fire Resistant Poles (M1b Scope)	2018	2023	$ 78	$ -	0.32	0.0041	1.20	0.0153
			Total	$4,575	$447	7.11	0.0014	24.16	0.0048

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 1~~3~~% incremental risk benefit on a mean basis compared to the Proposed Plan. But Alternative Plan #2 is approximately ~~*three*~~ *2.4 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.[74] 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."[75]

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.

[74] Please see the Appendix in Section IX for additional detail

[75] 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

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 (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.[76] 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

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[76] 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.

ignitions. SCE's target for this metric, at this time, is 2,426 circuit miles from 2018 through 2023.[77]

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,[78] by installing or replacing fuses on branch lines with faster acting current-limiting type fuses.

[77] 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 for reconductoring for 2021-2023. The 2021-2023 estimate will be reviewed and potentially revised prior to SCE's 2021 GRC application.

[78] 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).

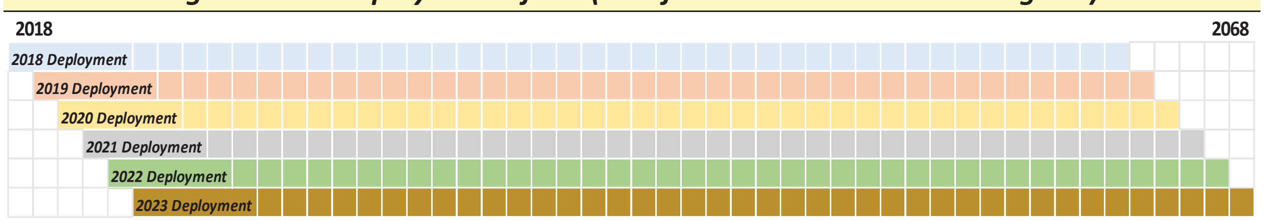
The RAMP analysis is extended out to 50 years to estimate the full benefit that the covered conductor assets provide over their useful life.

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.[79]

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)

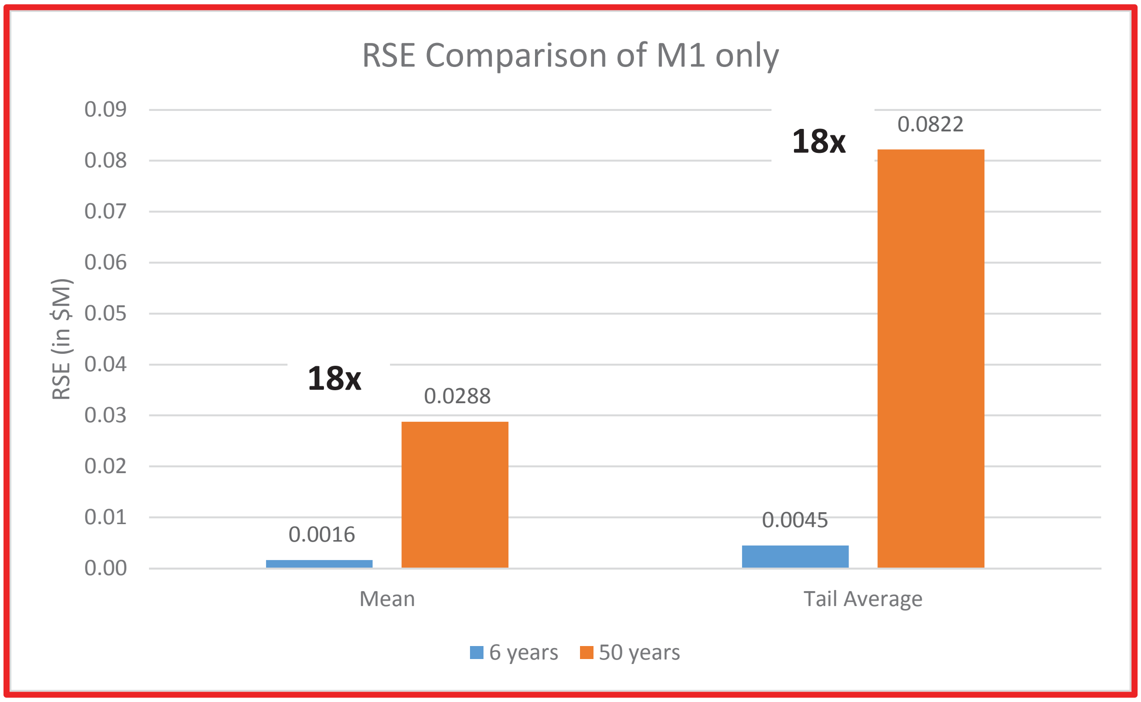


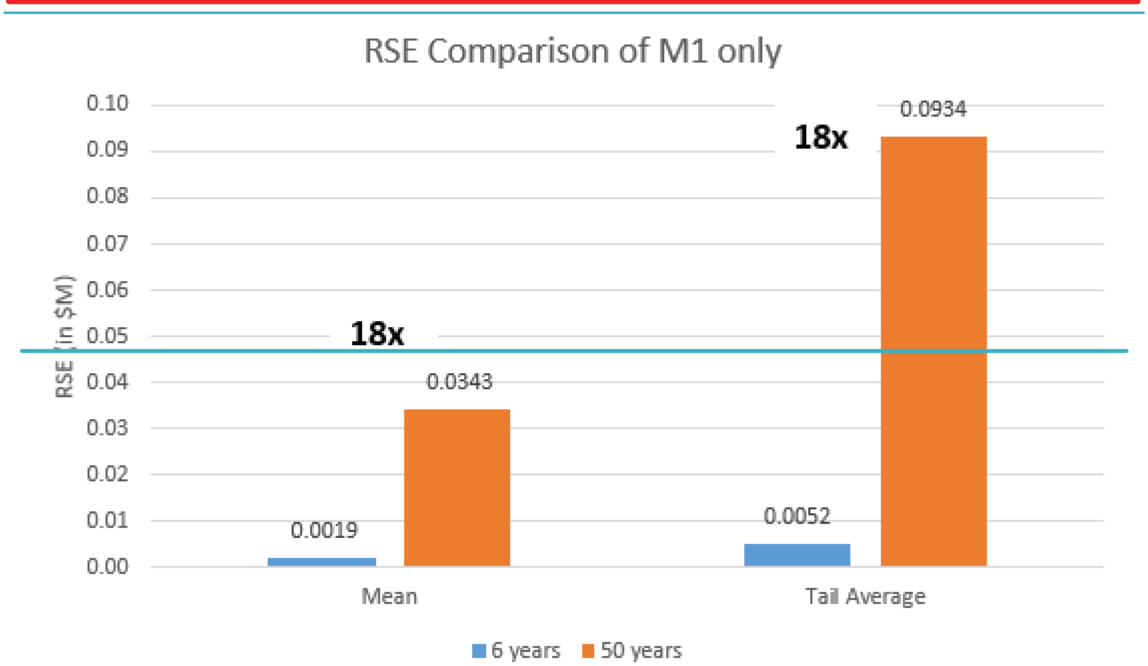
The chart below illustrates the Risk Spend Efficiency (RSE) for covered conductor (M1) for the 6-year RAMP period and the RSE for a 50-year period. The chart includes comparisons using both mean and tail average results.

[79] 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.

Appendix B
Clean Text Versions

(U 338-E)

Southern California Edison Company

Risk Assessment and Mitigation Phase

AMENDED VERSION
MARCH 2019

Contact With Energized Equipment

Chapter 5

Rosemead CA
November 15, 2018

Contents

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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]

[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	$345
	Baseline Risk	7.91	7.91	7.91
	Risk Reduction (MRR)	0.90	0.94	0.94
	Remaining Risk	7.01	6.97	6.97
	Risk Spend Efficiency (RSE)	0.0028	0.0028	0.0027
Tail Average (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	10.24	10.24	10.24
	Risk Reduction (MRR)	0.94	0.98	0.98
	Remaining Risk	9.30	9.26	9.26
	Risk Spend Efficiency (RSE)	0.0029	0.0029	0.0029

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.

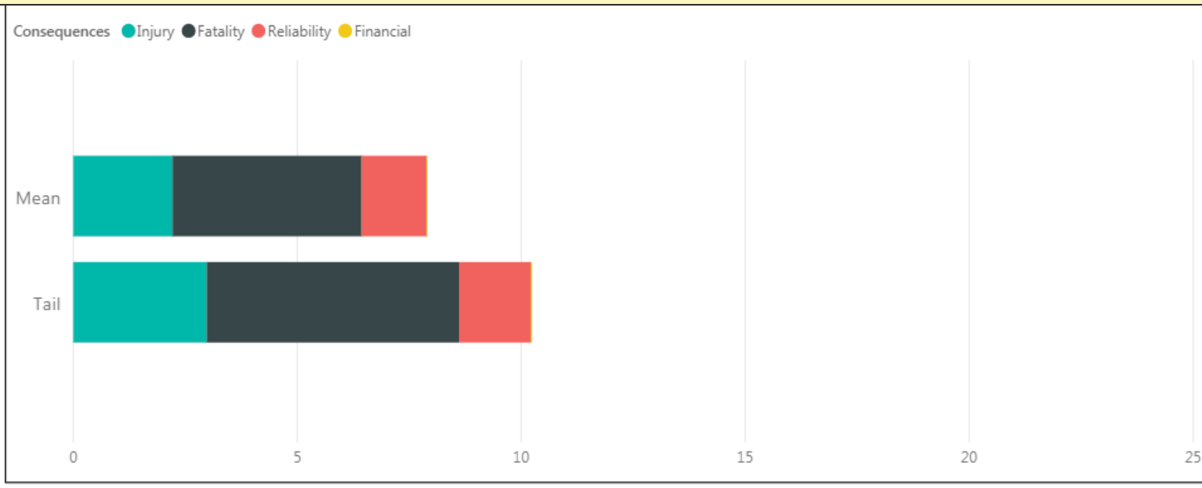
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

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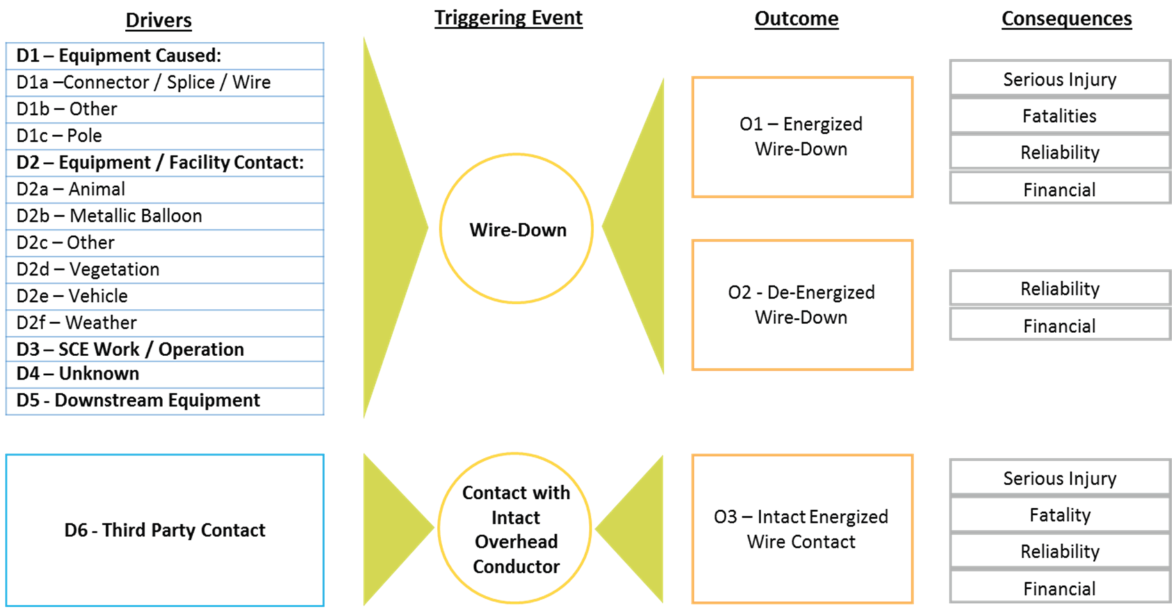
[7] *See* A.16-09-001, Exhibit SCE-02, Vol. 1, pp. 41-44.

[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.

Table II-1 – D1 (Equipment Cause) Frequencies

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%**

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.

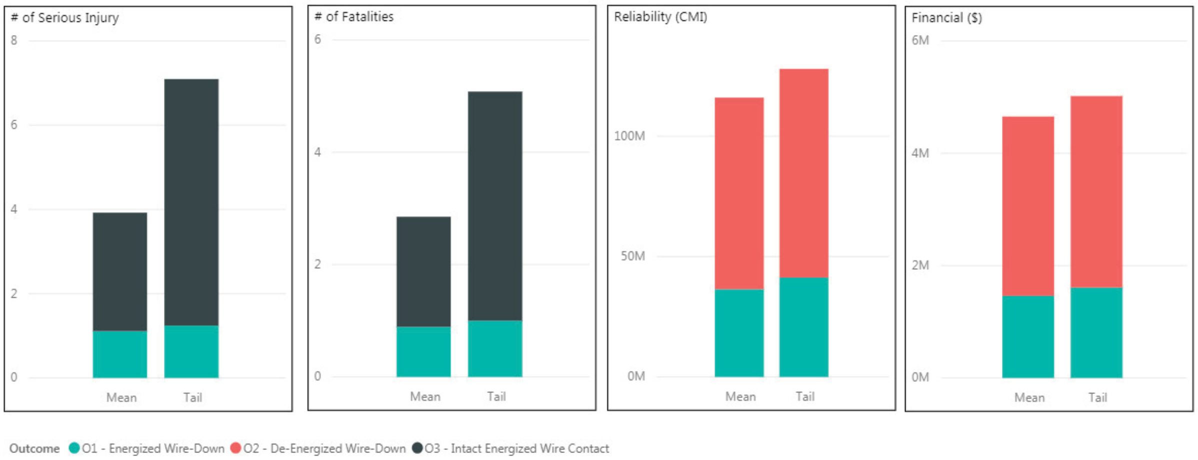
Figure II-3 – 2018 Outcome Likelihood[17]

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.

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

Outcome 3		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.	N/A	N/A
Model Outputs *(Annual Average)*	NU - Mean	2.8	2.0	N/A	N/A
	NU - Tail Avg	5.9	4.1	N/A	N/A

[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.

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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

[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.

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[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).

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[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.

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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	$ -	3.21	0.0045	3.36	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	0.3617	1.08	0.3785
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.60	0.0005	0.61	0.0005
			Total - Proposed Plan	**$1,910**	**$36**	**5.37**	**0.0028**	**5.61**	**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).

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	0.0140
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	2018	2023	$ 750	$ -	3.24	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	1.08	0.3788	1.14	0.3965
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.60	0.0005	0.61	0.0005
			Total - Alternative #1	**$1,994**	**$36**	**5.64**	**0.0028**	**5.86**	**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.

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	3.33	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	0.3596	1.08	0.3760
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.59	0.0005	0.60	0.0005
			Total - Alternative #2	**$2,034**	**$36**	**5.65**	**0.0027**	**5.90**	**0.0029**

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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Risk Assessment and Mitigation Phase

AMENDED VERSION
MARCH 2019

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.[2]

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[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] This includes amendments to SCE's GS&RP testimony filed on November 2, 2018 (SCE-01A-Amended) and December 26, 2018 (SCE-01A-Second Amended).

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,[3] Ignitions not associated with SCE.

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.

[3] 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 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.

Table I-2 – Summary Results (Annual Average over 2018-2023)[4]

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	$321	$837
	Baseline Risk	6.9	6.9	6.9
	Risk Reduction (MRR)	1.2	1.1	1.2
	Remaining Risk	5.7	5.8	5.7
	Risk Spend Efficiency (RSE)	0.0034	0.0033	0.0014
Tail Average (MARS)	*Cost Forecast ($ Million)*	$343	$321	$837
	Baseline Risk	24.0	24.0	24.0
	Risk Reduction (MRR)	4.0	3.7	4.0
	Remaining Risk	20.0	20.3	20.0
	Risk Spend Efficiency (RSE)	0.0117	0.0116	0.0048

Figures represent 2018 - 2023 annual averages.

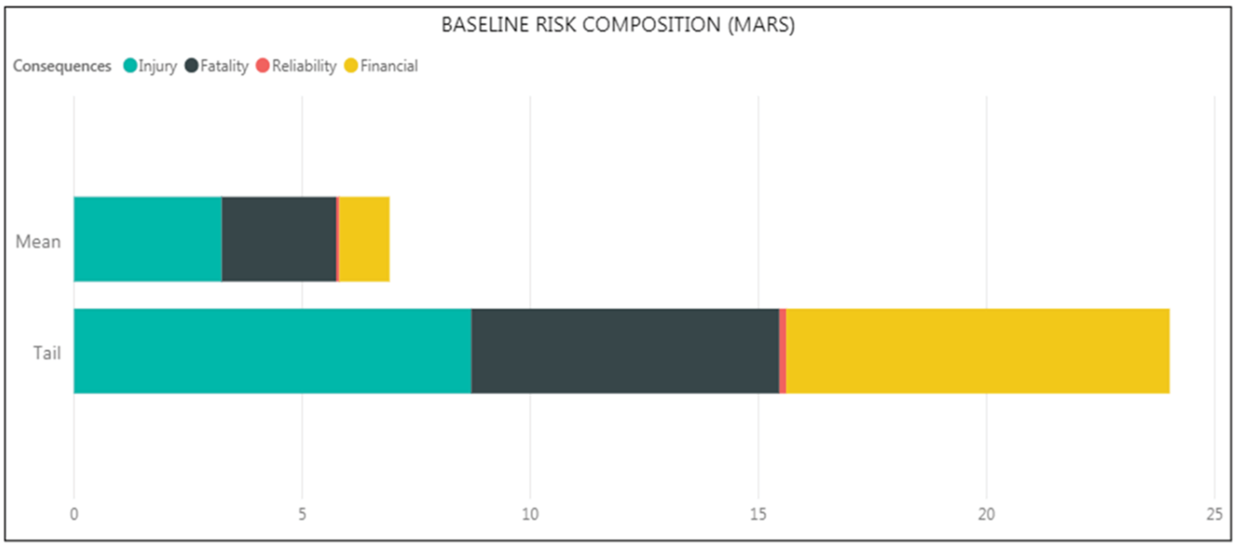
CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which 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.

[4] 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.

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,[5] 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[6] in October 2017 was notable for the number of fatalities and the time of year. As we moved into 2018, the Mendocino Complex fire,[7] 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."[8, 9]

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[10] 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;[11] non-drought conditions are becoming shorter.

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[5] 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.
[6] 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.
[7] 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.
[8] 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.
[9] 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 .
[10] 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.
[11] 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."[12] 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.[13]

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.[14] 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

[12] Governor Brown's State of Emergency Proclamation, January 17, 2014, *available at* https://www.gov.ca.gov/2014/01/17/news18368/.

[13] See Chapter 12, Climate Change for more details.

[14] 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).*

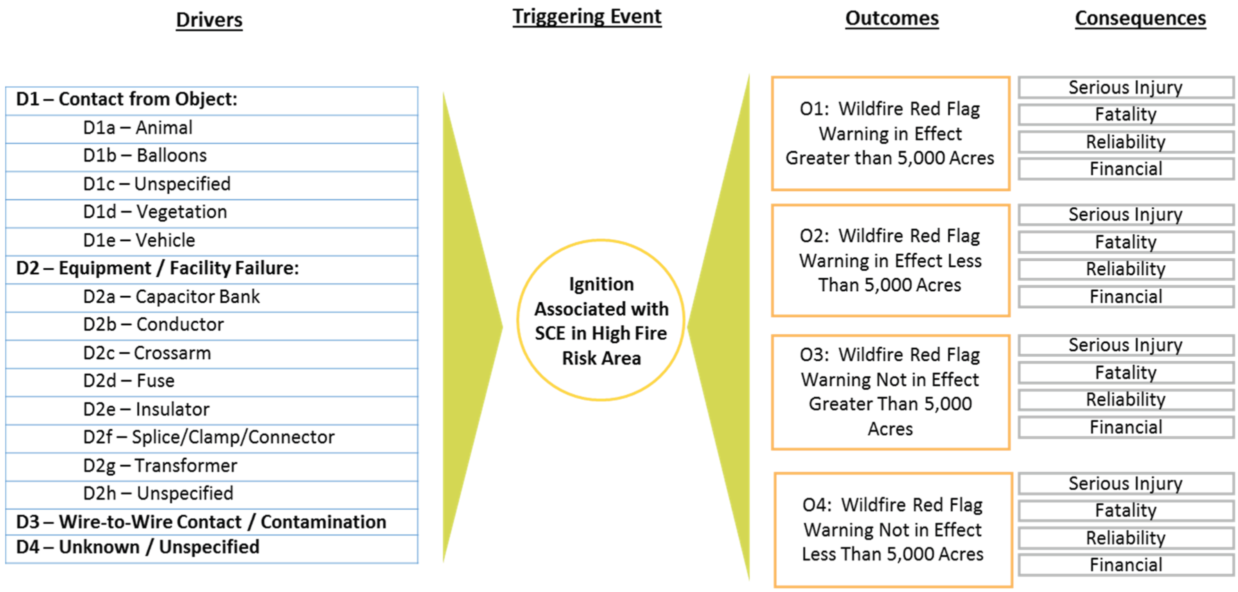
end 2020. This drives a difference in start and end dates for both filings, and necessarily causes the forecasts to vary.

- 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[15] 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.

[15] 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.[16] This analysis yielded four major categories of drivers:

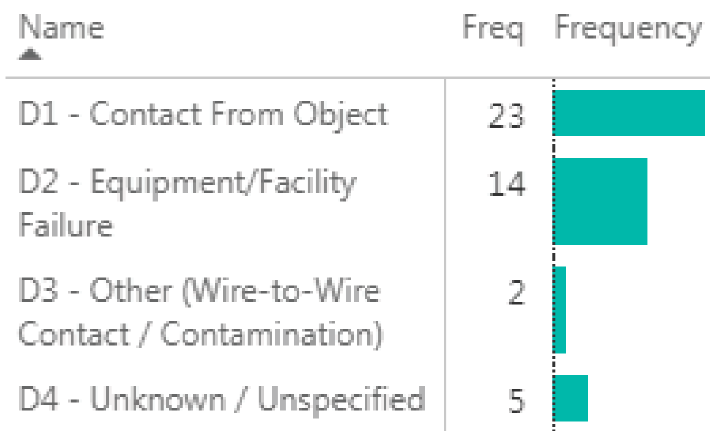
1. D1 - Contact From Object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/Facility Failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-Wire 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

[16] 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[17]



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.[18] Figure II-3 illustrates how the two most prevalent categories of faults can lead to wildfires.

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[17] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

[18] 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

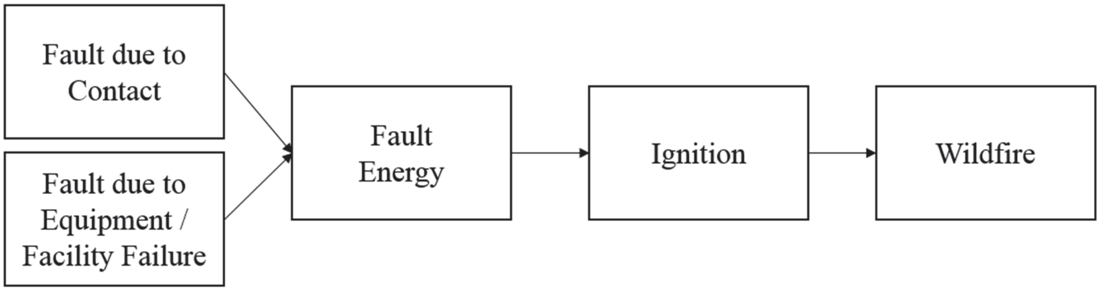

Table II-1 breaks down the different driver categories used within our risk modeling efforts. Table II-2 and Table II-3 break down the sub-drivers of Contact from Object and Equipment/Facility Failure, respectively.

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[19] 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[20] 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.

[19] Voltage potential is a measure of the propensity for electricity to travel from one point to another.
[20] 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.[21] 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

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[21] 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.[22]

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.[23] 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.

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[22] 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

[23] 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[24]

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."[25]

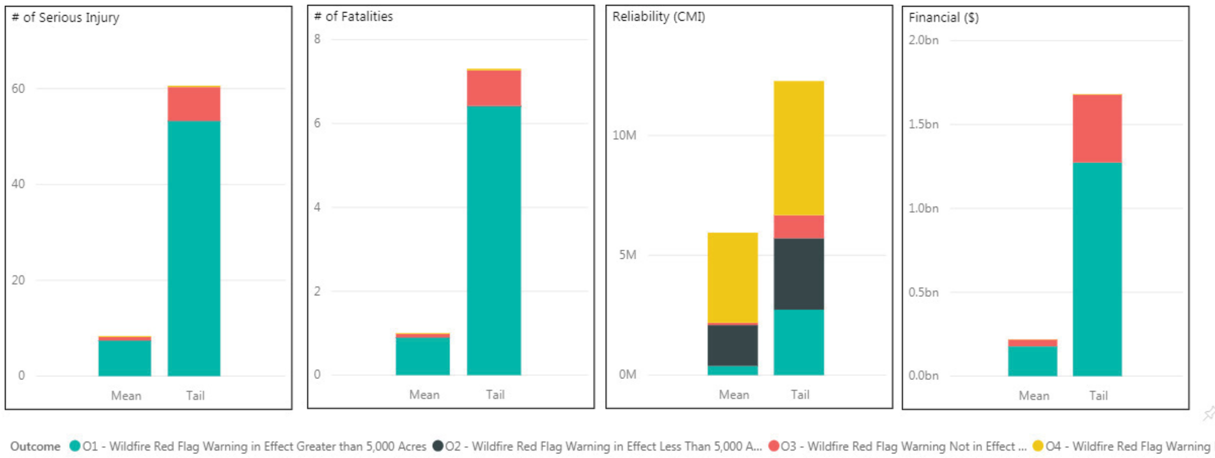
Please see Chapter 2 (Risk Model Overview) for additional detail regarding the outcome and consequence distribution modeling process. The sections that follow detail the data used to inform the development of these distributions.[26]

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.

[24] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[25] http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF
[26] 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.[27] 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

[27] 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[28,29]

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.

[28] 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.
[29] 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

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[30,31,32]

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.

[30] 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.
[31] 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*).
[32] 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.[33]

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.[34]

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.

[33] Source: http://calfire.ca.gov/communications/downloads/newsreleases/2017/CAL%20FIREandU.S%20ForestAnnouce129MillionDeadTrees.pdf

[34] 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),[35] 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.[36] 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.

[35] See SCE's Test Year 2018 GRC, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.
[36] 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,[37] and also impacts Driver D2 (Equipment Cause) for all years over the 2018-2023 RAMP period.[38] The OCP (C1a) impacts only Driver D2, for all years over the 2018-2023 RAMP period.[39]

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.[40] 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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[37] The specific sub-drivers impacted include D1a (Contact From Object – Animal), D1b (Contact From Object – Balloons), and D1d (Contact From Object – Vegetation).

[38] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

[39] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

[40] 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).

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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[41]

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[42] – 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

[41] 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*).

[42] 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.[43] 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[44] when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.[45] 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,[46] 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.[47] This approach lets SCE

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[43] 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.
[44] 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.
[45] 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."
[46] WCCP will have some safety and reliability benefits and OCP will have some wildfire benefits.
[47] 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 5,500 circuit miles of bare overhead conductor in HFRA that appear to be best suited for reconductoring with covered conductor[48] 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 (1,369 circuit miles)	Contact From Object Scope (1,058 circuit miles)
M1	Covered Conductor	Covered Conductor
M1a	Bare Conductor	Covered Conductor
M1b	Covered Conductor	Undergrounding

[48] SCE plans to complete deploying covered conductor for approximately 5,500 circuit miles by 2026.

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.[49]

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.[50] 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

[49] 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).
[50] See https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

equipment by installing underground conduit, cable, vaults, manholes, transformers, switches, 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[51] 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[52] and Fast Curve settings during Red Flag

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[51] 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.

[52] 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.[53] 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[54] 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.

[53] 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.

[54] 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[55] 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).[56] 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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[55] 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.

[56] 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)[57] 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

[57] 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.[58] The second sub-

[58] 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.[59] 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[60] – 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 - 1,058 Bare Conductor – 1,369	22,474
M1b *(Covered + Underground)*	Covered Conductor – 1,369	15,598

[59] 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).
[60] 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[61] that the shield will increase fire resistance, enabling the pole to withstand an "extreme" wildfire.[62]

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.

[61] 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.

[62] *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.[63]

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.

[63] 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)[64]

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	$ -	0.09	0.0009	0.30	0.0030
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	1.64	0.0014 *	5.28	0.0045 *
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0311	3.35	0.1075
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.90	0.0892	6.66	0.3119
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1029	0.95	0.3321
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.23	0.0033
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.84	0.0149	3.19	0.0561
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$ 137	$ -	0.60	0.0044	2.26	0.0165
			Total	$1,609	$447	7.02	0.0034	24.14	0.0117

*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.

[64] 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.

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.

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[65] 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.

[65] 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 higher than the RSE of the Alternative Plan #1, and significantly higher than the RSE of Alternative Plan #2.[66]

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 controls and mitigations in the Proposed Plan have a higher RSE than Alternative Plan #1 and Alternative Plan #2.

[66] Please see Section V.A for a discussion of underrepresentation of long-term benefits for covered conductor.

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[67]
C1 and M1 *(Proposed Plan)*	$1,263	1.73	1.37E-03	2,680 circuit miles: ***M1:*** *2,426 Covered* ***C1:*** *65 Covered + 189 Bare* *0 underground*
C1a and M1a *(Alternative Plan #1)*	$1,160	1.17	1.01E-03	2,680 circuit miles: ***M1a:*** *1,058 Covered + 1,369 Bare* ***C1a:*** *254 Bare* *0 underground*
C1 and M1b *(Alternative Plan #2)*	$4,277	2.08	0.486E-03	2,680 circuit miles ***M1b:*** *1,369 Covered+ 1,058 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).

[67] 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 45% identical (each plan includes at least 189 miles of bare conductor and 1,058 miles of covered conductor). Moreover, the variation in scope is less than 55% 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 (over 1,000 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.[68] The application then develops a mitigation-to-cost ratio for each conductor mitigation. It does not combine the different conductor mitigations.

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[68] 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.[69]

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.[70] The workpaper takes the GS&RP analysis of bare conductor versus covered conductor, and runs an equivalent analysis using the RAMP model.[71] 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.

[69] See Chapter 2 (Risk Model Overview) for additional detail regarding MARS, MRR and RSE.
[70] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).
[71] 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)[72]

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	$ -	0.06	0.0006	0.19	0.0020
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0023
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	2018	2023	$ 1,062	$ -	1.11	0.0010	3.62	0.0034
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.98	0.0313	3.41	0.1095
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.92	0.0899	6.79	0.3178
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.30	0.1044	0.98	0.3426
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0011	1.28	0.0035
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0150	3.26	0.0574
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.77	0.0084
M9a	Fire Resistant Poles (M1a Scope)	2018	2023	$ 112	$ -	0.51	0.0045	1.93	0.0173
			Total	**$1,480**	**$447**	**6.40**	**0.0033**	**22.41**	**0.0116**

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.[73] This was a key factor in our decision not to select Alternative Plan #1.

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[72] 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.

[73] 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	$ -	0.09	0.0009	0.30	0.0030
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1b	Underground Conversion	2018	2023	$ 4,175	$ -	1.99	0.0005	6.38	0.0015
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0313	3.33	0.1070
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.92	0.0898	6.63	0.3103
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1029	0.95	0.3316
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0010	1.24	0.0034
M6	Microgrids	2021	2023	$ 10	$ -	0.00	0.0000	0.00	0.0000
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0150	3.21	0.0565
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9b	Fire Resistant Poles (M1b Scope)	2018	2023	$ 78	$ -	0.32	0.0041	1.20	0.0153
			Total	**$4,575**	**$447**	**7.11**	**0.0014**	**24.16**	**0.0048**

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 1% incremental risk benefit on a mean basis compared to the Proposed Plan. But Alternative Plan #2 is approximately *2.4 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.[74] 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."[75]

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

[74] Please see the Appendix in Section IX for additional detail

[75] 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
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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.[76] 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.[77]

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[76] 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.

[77] 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,[78] by installing or replacing fuses on branch lines with faster acting current-limiting type fuses.

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for reconductoring for 2021-2023. The 2021-2023 estimate will be reviewed and potentially revised prior to SCE's 2021 GRC application.

[78] 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).

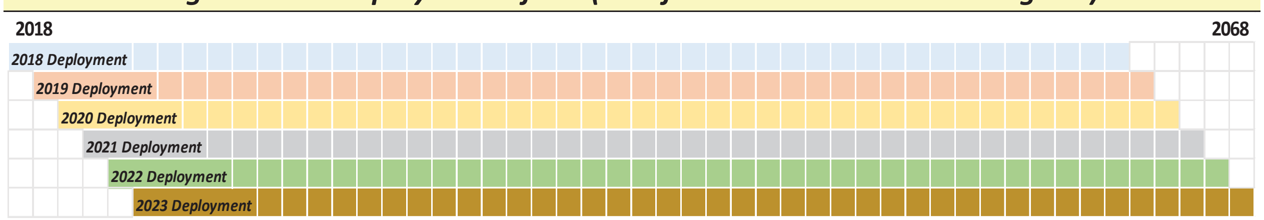
The RAMP analysis is extended out to 50 years to estimate the full benefit that the covered conductor assets provide over their useful life.

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.[79]

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)

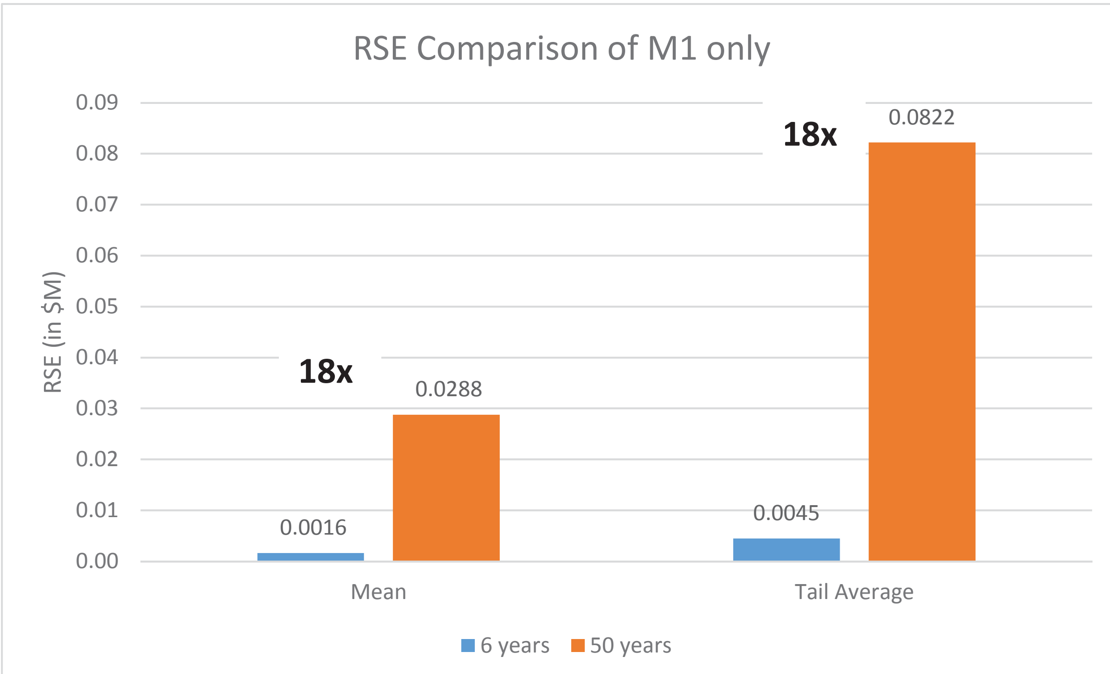


The chart below illustrates the Risk Spend Efficiency (RSE) for covered conductor (M1) for the 6-year RAMP period and the RSE for a 50-year period. The chart includes comparisons using both mean and tail average results.

[79] 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.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Investigation Into the November 2018 Submission of Southern California Edison Risk Assessment and Mitigation Phase.	I.18-11-006

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) AMENDMENT TO PORTIONS OF 2018 RISK ASSESSMENT AND MITIGATION PHASE REPORT (U 338-E)** on all parties identified on the attached service list(s) for I.18-11-006 Service was effected by one or more means indicated below:

☑ Transmitting the copies via e-mail to all parties who have provided an e-mail address.

☑ Placing the copies in sealed envelopes and causing such envelopes to be delivered by US Mail to the offices of the ALJ(s) or other addresses(s).

ALJ Eric Wildgrube
CPUC
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San Francisco, CA 94102

Executed **March 14, 2019,** at Rosemead, California.

/s/ Alejandra Arzola
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