Docket:	:	A.18-09-002
Exhibit Number	:	
Reference Number	:	CalAdvocates-03
Commissioner	:	M. Picker
ALJ	:	R. Haga
Witnesses	:	M. Botros
		S. Chase
		S. Logan
		N. Stannik

PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

Application of Southern California Edison Company for Approval of Its Grid Safety and Resiliency Program (GSRP)

Public Advocates Office
Supporting Attachments

San Francisco, California
April 23, 2019

All documents are from Exhibit CalAdvocates-01 except 31 and 35, which are from CalAdvocates-02.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Hunly Chy
Title: Engineer
Dated: 09/28/2018

Question 07:

On page 22, SCE cites "research that determined [a more progressive approach] to be effective under severe wildfire conditions." Please provide a citation/reference to such research.

Response to Question 07:

Beyond the work papers highlighted below, SCE has enclosed the document titled "Covered Conductor – Everything You Need to Know (Compendium)" dated October 8, 2018, that represents a comprehensive review of research, bench marking and other documents that were reviewed or created in development of the WCCP portfolio as proposed within A.18-09-002. The Compendium will be updated as warranted based on future document reviews.

Please refer to the following work papers submitted in support of SCE-01A (A. 18-09-002) on September 26, 2018:

- An Engineering Analysis on Impacts of Contact from Objects (CFO) on Bare vs. Covered Conductor (document was resubmitted on October 3, 2018 to clear document links)
- NEETRAC Final Report
- SCE Summary of Covered Conductor Touch Current - NEETRAC Report

Covered Conductor CompendiumDR.pdf

Covered Conductor - Everything You Need To Know (Compendium)

Prepared by Apparatus & Standards Engineering Group

T&D Engineering

October 8, 2018

Purpose

- There has been a vast amount of literature search, testing, calculation, benchmarking and standards development by T&D Engineering for the deployment of Covered Conductor
- As a result, multiple work documentation on various topics concerning Covered Conductor has been created for supporting the issuance of SCE specifications, design and construction standards for covered conductor
- These topics on Covered Conductor are summarized on the "Table of Contents" slide.
- The purpose of this slide deck is to consolidate and condense the key thoughts of these works into a single document, providing a comprehensive overview of covered conductor

Table of Contents

Chapter I
What is Covered Conductor?
Why Covered Conductor?

Energy for What's Ahead[SM]

SOUTHERN CALIFORNIA EDISON®

1. The Evolution of Covered Conductor Design

This section introduces the high-level understanding of Covered Conductor and how it has evolved from a simple model in the early 1970s to a robust design today that mitigates contact issues and achieves long service life

A Brief History

- Covered Conductor has been used by utilities since the 1970s in Europe and the U.S.
  - Key driver: reliability improvement in dense vegetation areas, such as forests in Scandinavia, the U.K., New England, etc.
- Other drivers expand the use of covered conductors:
  - Tokyo, Japan: public safety in dense population
  - Southeast Asia (Thailand, Malaysia): animal protection (snakes, monkeys, rodents), and dense vegetation, also public safety in downtown Bangkok
- Reduction of “bushfires” has become a key driver for replacing bare with covered conductor in Australia
- Over the years, significant development in the covered conductor design led to improved performance and extended life

Nomenclature of Covered Conductor

- Covered conductor is a widely accepted and used term for distinguished from bare conductor
- The term indicates a conductor being “covered” with insulating materials to provide incidental contact protection
- Covered conductor is used in the U.S. in lieu of “insulated conductor”, which is reserved for grounded overhead cable
- Other parts in the world use the term “covered conductor”, “insulated conductor”, “coated conductor” interchangeably
- Covered conductor is a generic name for many sub-categories of conductor design and field construction arrangement
- Covered conductor in the U.S.:
    - Tree wire
        - Term was widely used in the U.S. in 1970’s
        - Associated with simple one layer cover
        - Used to indicate cross-arm construction
    - Spacer cable
        - Associated with construction using trapezoidal insulated brackets for suspending covered conductor
    - Aerial bundled cable (ABC)
        - Installation of underground cable on poles with benefits of being grounded
- Covered Conductor in Europe:
    - SAX, PAS/BLX, BLX-T are some names for covered conductor used in Scandinavia for installations in forests
    - CC/CCT are covered conductor and covered conductor with extra thickness are used in Australia, the Far East
- Covered Conductor at SCE:
    - The term “Covered Conductor” was introduced to SCE standards in Q1, 2018, previously, the term "tree wire" was used
    - SCE is more familiar with “aerial cable” to indicate field-bundled underground cable (with or without jacket) prior to 2000’s, and manufacturer “pre-bundled” underground cable on air (ABC) in the 2000’s
    - Current SCE specified Covered Conductor is more robust than CCT with has better UV protection

Single Layer Covered Conductor

- Characteristics:
  - Single Layer
  - Typically, Low Density Polyethylene (insulating material)
  - Covering Thickness ranges from 0.091 to 0.130 inches
- Lower impulse strength than the two or three layer design
- Provides some resistance to outages caused by tree and wildlife contact

Two Layer Covered Conductor

- Characteristics:
  - Two Layers
    - Layer A: Polyethylene (PE)
      - Insulating material
      - 0.080 inches
    - Layer B: High Density Polyethylene (HDPE)
      - Insulating Material
      - Tougher than layer A
        - Abrasion Resistant
      - 0.080 inches
- Higher impulse strength than the single layer design

Three Layer Covered Conductor

- Characteristics
  - Three Layers
    - Layer A: Conductor Shield
      - Semiconducting layer
      - Reduces Voltage Stress
    - Layer B: Polyethylene Layer
      - Insulating Layer
      - Can be crosslinked (XLPE)
    - Layer C: Polyethylene Layer
      - Insulating Layer
      - Can be high density and/or crosslinked

- Higher impulse strength than the single layer design and two layer design

SCE's Evolution

Single Layer

- 150 mils HDPE

3 Layer 75°C Rated

- 15 mils conductor shield
- 75 mils LDPE Inner Layer
- 75 mils HDPE Outer Layer

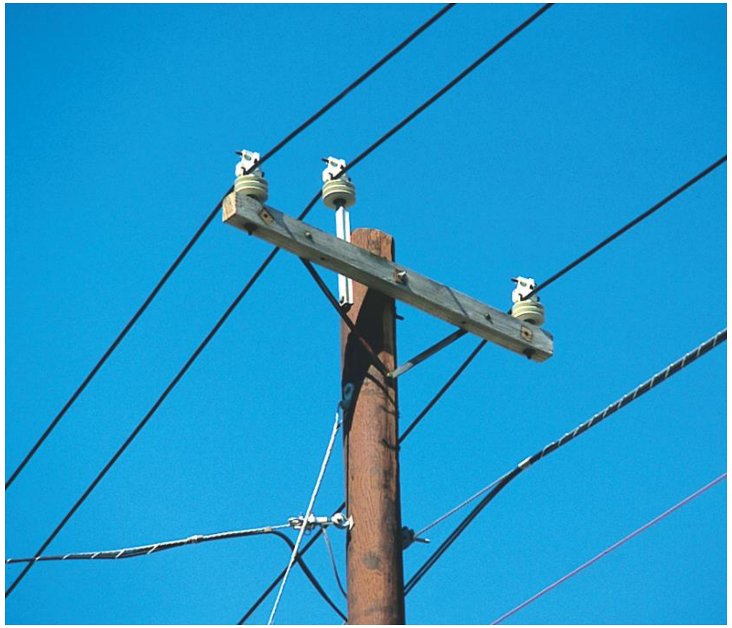
3 Layer

90°C Rated

- 15 mils conductor shield
- 75 mils XL-LDPE Inner Layer
- 75 mils XL-HDPE Outer Layer

Covered Conductor Installation Options

- Cross-arm Construction
  - (aka Tree Wire)



Most of SCE installations on Cross-arm (SCE uses grey to reduce the impact of sun light heating effect, thus increase ampacity)

- Compact Construction
  - (aka Spacer Cable)

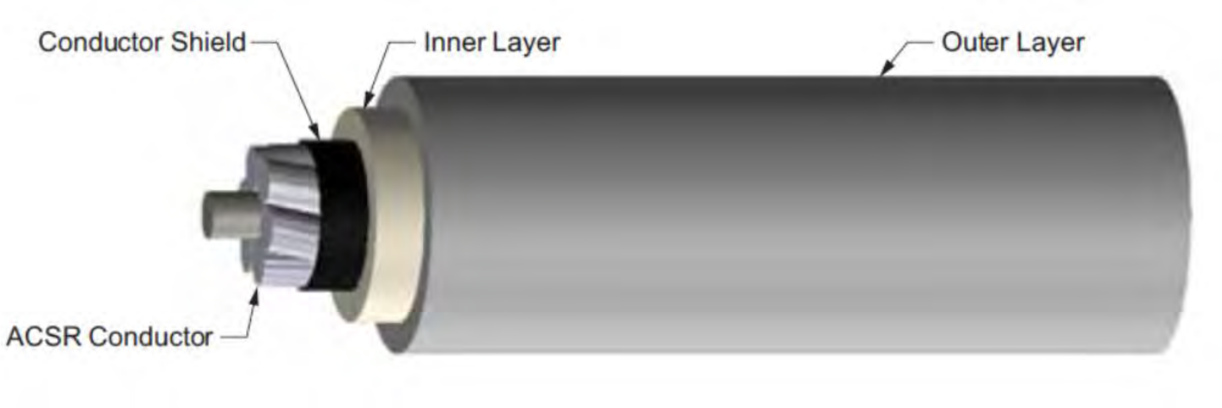
Some installations will be space cable (e.g. replacement of tree attachments)

2. SCE Covered Conductor Design

This section provides more insights of SCE Covered Conductor Design – layer by layer and the functions of each layer (sheath)

SCE Design

- Three Layer Covered Conductor
  - Conductor
    - Aluminum Conductor Steel-Reinforced (ACSR)
    - Hard Drawn Copper (HDCU)
  - Conductor Shield
    - Semiconducting Thermoset Polymer
  - Inner Layer
    - Crosslinked Low Density Polyethylene
  - Outer Layer
    - Crosslinked High Density Polyethylene

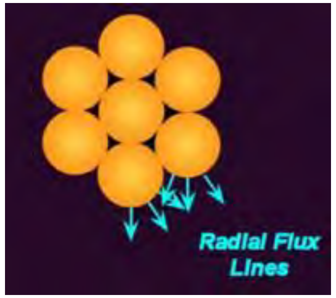


Conductor

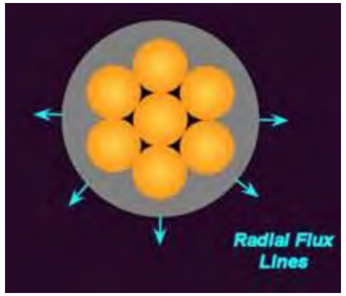
- Aluminum Conductor Steel-Reinforced (ACSR)
  - Sizes
    - 1/0 AWG (6/1 Strand)
    - 336.4 AWG (18/1 Strand)
    - 653 AWG (18/3 Strand)
- Hard Drawn Copper (HDCU)
  - For use in coastal areas (within 1 mile of the coast)
    - Copper is more resistant to corrosion than Aluminum
  - Sizes
    - #2 AWG (7 Strand)
    - 2/0 AWG (7 Strand)
    - 4/0 AWG (7 strand)

Conductor Shield

- Material: Semiconducting Thermoset Polymer
- Reduces stress concentrations caused by flux lines from individual conductor strands.
  - Transforms strands into a single uniform conducting cylinder



Flux lines without a conductor shield



Flux lines with a conductor shield

- The reduction of electrical stress, especially if the covered conductor is in contact with another object, will help preserve the integrity of the insulation and lengthen the useful service life of the covered conductor.

Inner Layer

- Material: Crosslinked Low Density Polyethylene (XL-LDPE)
- Insulating Layer
  - Contributes to the high impulse strength of the covering, which will protect the conductor from phase-to-phase and phase-to-ground contact
- Crosslinking will allow the material to retain its strength and shape even when heated

Outer Layer

- Material: Crosslinked High Density Polyethylene (XL-HDPE)
- Insulating Layer
  - Contributes to the high impulse strength of the covering, which will protect the conductor from phase-to-phase and phase-to-ground contact
- Abrasion and Impact Resistant
- Environmental Stress-Crack Resistant
- Track Resistant
- UV Resistant
- Crosslinking (XL) will allow the material to retain its strength and shape even when heated
- HDPE uses Titanium Dioxide as the most effective UV inhibitor, and providing the best track resistant

Temperature Rating

- Normal Operation: 90ºC
- Emergency Operation: 130ºC
- Short Circuit Operation: 250ºC

Covered Conductor vs. Bare Comparison

- ACSR Covered Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
1/0	ACSR (6x1)	XL-HDPE (165 mils)	0.277	0.728	271
336.4	ACSR (18x1)	XL-HDPE (165 mils)	0.564	1.014	550
653.9	ACSR (18x3)	XL-HDPE (180 mils)	0.973	1.313	835

- ACSR Bare

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
1/0	ACSR (6x1)	N/A	0.146	0.398	280
336.4	ACSR (18x1)	N/A	0.365	0.684	605
653.9	ACSR (18x3)	N/A	0.677	0.953	920

Covered Conductor vs. Bare Comparison

- Copper Covered Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
#2	HDCU (7)	XL-HDPE (165 mils)	0.316	0.622	240
2/0	HDCU (7)	XL-HDPE (165 mils)	0.569	0.744	367
4/0	HDCU (7)	XL-HDPE (165 mils)	0.845	0.852	488

- Copper Bare Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
#2	HDCU (7)	N/A	0.205	0.292	260
2/0	HDCU (7)	N/A	0.411	0.414	405
4/0	HDCU (7)	N/A	0.653	0.522	540

3. Contact with Foreign Object

This section demonstrates how Covered Conduct reduces ignition risks during contact with foreign object or other conductor by performing a complex engineering analysis and testing impacts of contact on Covered Conductor

Contact with Foreign Object

- Covered conductors will prevent incidental contacts that cause phase-to-phase and phase-to-ground faults caused by:
  - Vegetation/Palm fronds
  - Conductor slapping
  - Wildlife
  - Metallic Balloons
- Analysis of computer modeled scenarios and field testing supports that covered conductor will prevent faults caused by incidental contact.

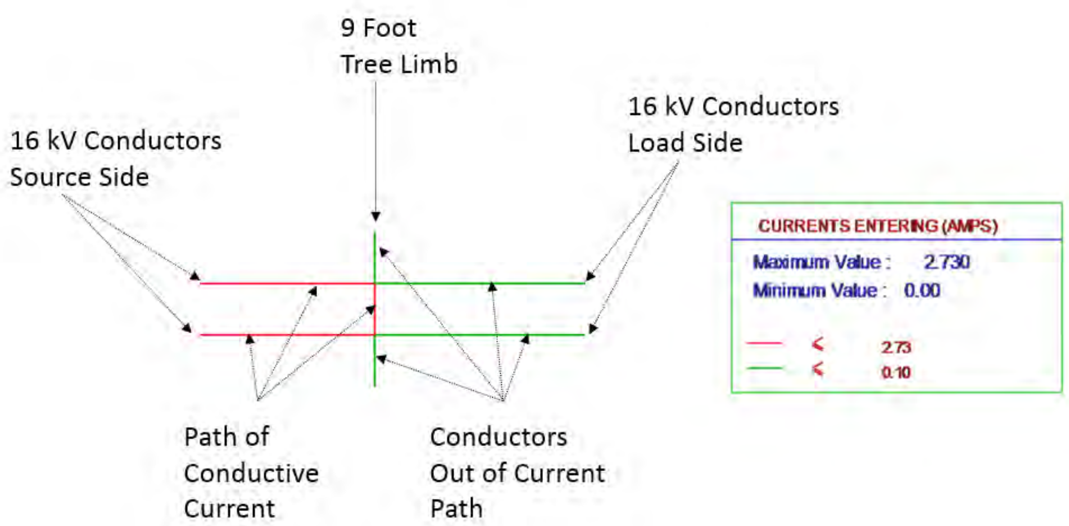
Contact with Foreign Object Using Computer Modeling & Simulation

- An SCE study analyzed the effectiveness of the covering in preventing phase-to-phase faults due to incidental contact
- The study also analyzed the energy absorbed by the foreign object when contact with two covered conductor is significant low and not sufficient to start a fire.
- Scenarios Modeled in computer models using two complex electric power engineering program tools (PSCAD and CDEGS):
  - Tree/Vegetation phase-to-phase contact
  - Conductor Slapping
  - Wildlife phase-to-phase contact
  - Metallic Balloon phase-to-phase contact

Example of Computer Modeling & Simulation Results for Tree Contact (CDEGS)

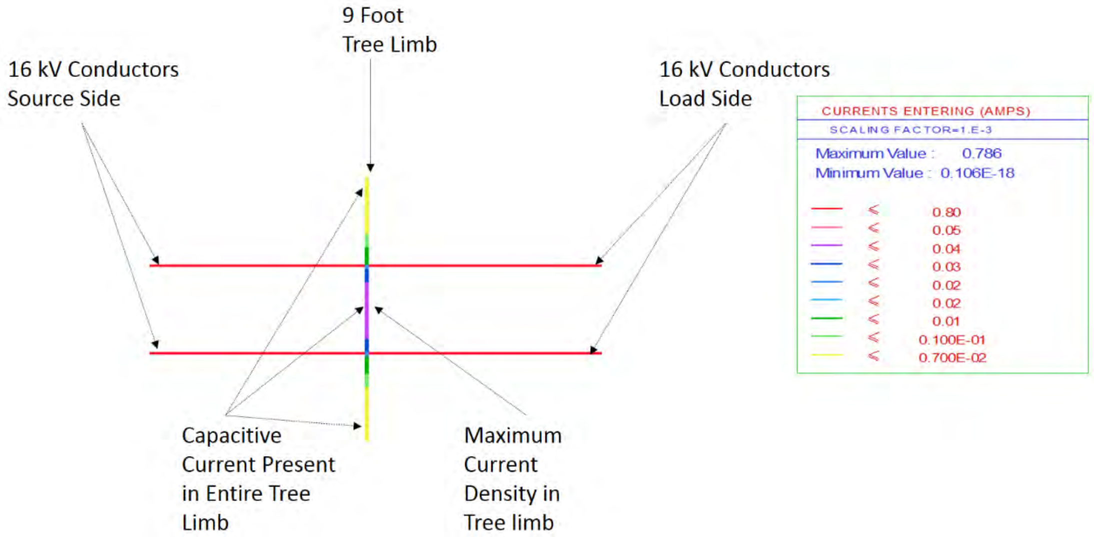
Case 1: Tree on Two Bare Conductors

Maximum Current through object: **2.7 A**



Case 2: Tree on Two Covered Conductors

Maximum Current through object **0.04 mA**



Study Conclusion

- The analysis concluded that a foreign object contact with covered conductors will not cause a fault
- The results showed that covered conductors reduce the energy from tens of thousands of watts to well under one milliwatt.
- This reduction is expected to be sufficient to prevent ignition

Simulation Method	Conductor Type	Current in Branch	Resistance of Branch	Power into Branch
PSCAD	Bare Conductor	2800 mA	5800 Ω	45,472 W
	Covered Conductor	0.18 mA	5800 Ω	0.00019 W
CDEGS	Bare Conductor	2730 mA	5800 Ω	43,227 W
	Covered Conductor	0.04 mA	5800 Ω	0.00001 W

Field Testing

- Field testing was performed at SCE' EDEF Test Facility in Westminster to validate the computer model study
- Tests performed for contact with covered conductors only
- No tests performed for contact with bare conductors, because this information is well studied by the industry
- Scenarios tested:
    - Tree/Vegetation phase-to-phase contact
    - Conductor Slapping
    - Wildlife phase-to-phase contact
    - Metallic Balloon phase-to-phase contact

Palm Frond Contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the palm frond

Tree Branch contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the tree branch

Conductor Slapping

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to both covered conductors

Wildlife Contact

- 700 Ω resistor simulated animal contact
- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to resistor

Metallic Balloon Contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the metallic balloon

033

Field Test Conclusion

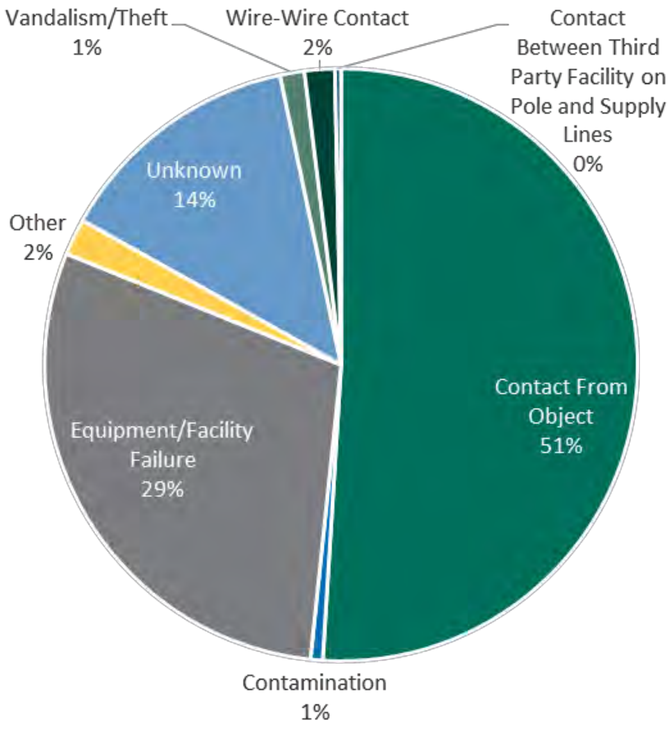
- Field testing validated that covered conductor will prevent faults and reduce the chance of ignition due to incidental contact

4. Wildfire Mitigation Effectiveness

This section illustrates the analysis of the fire mitigation effectiveness of covered conductors.

Fault to Fire Analysis

- Initial studies analyzed fault types associated with High Fire Risk Areas and fires produced
- Historical Ignition Source Distribution



System Level Risk Distribution

- A ignition risk percentage was tied to each fault type, based on historical data of fires produced by each fault

	"Frequency of Fault"	"Likelihood it leads to a Fire"	"Fires Produced"	"Normalizing for Total Wildfire Risk"	
Fault Type	Annual TEF	CP	Annual Fires		Annual CRR
Contact From Object	**895**	**2.6%**	**23.3**	**53%**	**5,303,030**
Animal	250	2.0%	5.0	11%	1,136,364
Balloon	152	3.1%	4.7	11%	1,060,606
Other	48	6.9%	3.3	8%	757,576
Vegetation	238	3.1%	7.3	17%	1,666,667
Vehicle Hit	207	1.5%	3.0	7%	681,818
Equipment/Facility Failure	**1,354**	**1.0%**	**13.3**	**30%**	**3,030,303**
Capacitor Bank	8	8.0%	0.7	2%	151,515
Conductor/Wire	145	2.8%	4.0	9%	909,091
Crossarm	39	0.8%	0.3	1%	75,758
Fuse/BLF/Cutout	98	0.3%	0.3	1%	75,758
Insulator	24	7.0%	1.7	4%	378,788
Other	111	2.4%	2.7	6%	606,061
Splice/Connector/Tap	138	1.9%	2.7	6%	606,061
Transformer	791	0.1%	1.0	2%	227,273
Other	**571**	**1.3%**	**7.3**	**17%**	**1,666,667**
Total	**2,819**	**1.6%**	**44.0**	**100%**	**10,000,000**

Covered Conductor Ignition Risk Mitigation

- Covered Conductor was found to be effective against Contact from Object faults, such as:
  - Animal
  - Balloon
  - Vegetation
  - Other
- Covered Conductor was found to be effective against some overhead equipment faults due to:
  - Conductor/Wire
  - Splice/Connector/Tap
- Overall, mitigation effectiveness of covered conductor was found to be 60%

	Covered Conductor			
Fault Type	**Mitigated Events**	**Equivalent Fires**	**Mitigation Effectiveness**	**MRR**
Contact From Object	**677**	**19.5**	**84%**	**4,442,340**
Animal	250	5.0	100%	1,136,364
Balloon	152	4.7	100%	1,060,606
Other	37	2.5	76%	578,704
Vegetation	238	7.3	100%	1,666,667
Vehicle Hit	0	0.0	0%	0
Equipment/Facility Failure	**283**	**6.7**	**50%**	**1,515,152**
Capacitor Bank	0	0.0	0%	0
Conductor/Wire	145	4.0	100%	909,091
Crossarm	0	0.0	0%	0
Fuse/BLF/Cutout	0	0.0	0%	0
Insulator	0	0.0	0%	0
Other	0	0.0	0%	0
Splice/Connector/Tap	138	2.7	100%	606,061
Transformer	0	0.0	0%	0
Other	**0**	**0.0**	**0%**	**0**
Total	**960**	**26.2**	**60%**	**5,957,492**

5. Alternatives Comparison

This section describes the alternatives considered and provides a comparison on their fire mitigation effectiveness and cost.

Alternatives Considered

- Wildfire Mitigation Options
  - Covered Conductor
    - Replace existing conductor with new, appropriately sized, covered conductor
  - Bare Conductor
    - Replace existing conductor with new, appropriately sized, bare conductor
  - Underground Relocation
    - Relocate existing overhead primary voltages to underground

Alternatives Mitigation Effectiveness Analysis

- Based on input from Distribution / Apparatus Engineering, a mitigation is assumed to have either 0% (i.e. none) or 100% (i.e. complete) effectiveness against a particular subset of faults within ODRM

	ODRM Cause Code	Covered Conductor Effective?	Bare Conductor Effective?	Undergrounding Effective?[1]
Contact From Object	Animal	**Yes**	No	**Yes**
	Balloon	**Yes**	No	**Yes**
	Foreign Material; Ice/Snow	**Partial (Yes for 'Foreign Material')**	No	**Yes**
	Vegetation Blown; Vegetation Overgrown	**Yes**	No	**Yes**
	Vehicle Hit	No	No	**Yes**
Equipment / Facility Failure	Transformer	No	No	**Yes**
	Conductor / Wire	**Yes**	**Yes**	**Yes**
	Splice / Connector / Tap	**Yes**	**Yes**	**Yes**
	Fuse / BLF / Cutout	No	No	**Yes**
	Lightning Arrestor	No	No	**Yes**
	Crossarm	No	No	**Yes**
	Pothead	No	No	**Yes**
	Insulator	No	No	**Yes**
	Switch / Disconnect AR	No	No	**Yes**

1. Undergrounding Effectiveness shown only include the mitigation of CFO faults and OH Equipment/Facility Failures, and does not include the additional risk of undergrounding (vault-lid ejection, UG cable and equipment failures, etc.)

Mitigation Effectiveness Comparison

- The following mitigation effectiveness values were assigned to each alternative:

Alternative	**Mitigation Effectiveness**
Covered Conductor	60%
Bare Wire	15%
Underground	100%

Cost Comparison

- The following Unit Cost values were assigned to each alternative:

Mitigation Option	Relative Mitigation Effectiveness Factor	Cost per Mile ($ million)	Mitigation-Cost Ratio
Re-conductor - Bare	0.15	0.30	0.50
Re-conductor - Covered	0.60	0.43	1.40
Underground Conversion	1.00	3.00	0.33

Conclusion

- While re-conductoring with bare conductor would have lower cost, and underground conversion would have greater benefit, re-conductoring with covered conductor has greater overall value.
- A dollar spent re-conductoring with covered conductor provides nearly three times as much value in wildfire risk mitigation as dollar spent re-conductoring with bare conductor
- A dollar spent re-conductoring with covered conductor provides over four times as much value in wildfire risk mitigation as dollar spent on underground conversion.

6. Safety Advantages

Safety

- In the case of a downed conductor, covered conductors will provide a safety advantage over bare wire.
- The covering on the covered conductor will reduce the charging current enough to result in, at most, a slight shock during human contact while contact with bare wire will result in electrocution.
- While evidence of a reduced charging current is available in multiple industry papers, SCE has sponsored a test with NEETRAC on covered conductor touch current to verify this data

Effects of Electrical Current

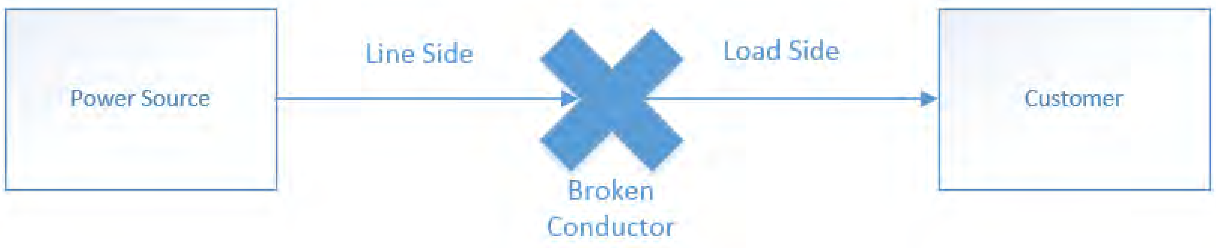
- Effects of Electrical Current on the Human Body

Current	Effect
Below 1 mA	Generally not Perceptible
1 mA	Faint Tingle
5 mA	Slight Shock; Not painful but disturbing. Average individual can let go
6-25 mA (women) **9-30 mA (men)**	Painful shock, loss of muscular control. The freezing current or "let-go" range. Individual cannot let go, but can be thrown away from the circuit if extensor muscles are stimulated
50-150 mA	Extreme pain, respiratory arrest (breathing stops), severe muscular contractions. Death is possible

NEETRAC Testing – Energized Downed Conductor

- The following are test cases of energized wire down scenarios that were simulated and empirically tested by NEETRAC
  - Person holding broken **covered conductor** on **line side**
  - Person holding broken **covered conductor** on **load side**
  - Person holding broken **bare conductor** on **line side**
  - Person holding broken **bare conductor** on **load side**

*Note that bare conductor test cases were not performed in the laboratory.



NEETRAC Testing

- Test Information:
  - Conductor: 1/0 Covered Conductor
  - Source: 12.447 kV
  - Test Results: Human contact current measured

	Covered Conductor		Bare Conductor
	Simulation Results (Theoretical Value)	Lab Test Results (Actual Values)	Simulation Results (Theoretical Value)
Line Side	0.220 mA	0.227 mA	5,300 mA
Load Side	0.218 mA	0.227 mA	34.2 mA

- Conclusion:
  - Covered Conductor Touch Current: Generally Not Perceptible
  - Bare Conductor Touch Current: Electrocution
  - Overall, covered conductors can potentially provide public safety benefits during wire down events

Chapter II
Life Expectancy

Energy for What's Ahead[SM]

SOUTHERN CALIFORNIA EDISON®

1. Expected Service Life

This section describes the life expectancy of covered conductors, the basis for the projection, and factors that influence service life.

Service Life

- SCE expects covered conductors to have a service life of **45 years**
- Conclusion of 45 years is based on
  - Manufacturer response
  - Historical Records
  - SCE experience with similar products

Manufacturer Survey

- Manufacturer consensus is that the covered conductor service life is expected to be 40 years minimum

Surveyed Questions	Supplier 1	Supplier 2	Supplier 3
1. What is the expected service life of the covering?	Minimum of 40 years, and probably 60 plus years	40 years	40 years
2. What is the expected service life of the conductor?	Useful service life in excess of 80 years	40 years	40 years
3. What is the expected service life of the covered conductor as a whole?	Excess of 67 years	40 years	40 years

Basis for Expected Service Life

- Advancement of compound technology and the upgrade of manufacturing equipment
- Known service life of XLPE is 40 years minimum
- Conformance to and successful passing of qualification tests ensures life expectancy
- Historical records with systems installed since 1951 are still in operation and performing as designed 67 years ago

Factors that Influence Service Life

- Conductor Temperature
  - Operating at extreme temperature is known to damage the conductor and/or covering
- Extreme contamination
- Severe UV exposure
- Installation methods and condition
- Type and Quality of Accessories

Qualification Testing

- SCE requires the following tests to ensure the longevity of the conductor
  - UV Testing
  - Environmental Stress Cracking
  - Track Resistance
  - Maximum Dielectric Constant
- Passing qualification tests ensures that the covered conductor deployed in SCE facilities meet industry standard and are high quality
- Passing ensures that the covering can perform as intended for a 45 year operating life

2. UV Resistance

This section describes the requirements of the UV resistance testing.

Sunlight (UV) Resistance Testing

- SCE requires conformance to ICEA S-121-733-2016 Sunlight Resistance (UV) Testing
- Testing will accurately predict, on an accelerated basis, the effect of sunlight
- UV testing will involve inducing property changes associated with the end use conditions, including the effects of sunlight, moisture, and heat. Testing requires specimens to be exposed to xenon-arc radiation and water-spray exposure.
- The exposure time is 720 hours with a radiation level of 0.35 Watt/meter. This radiation level was chosen based on the most extreme summer weather similar to the state of Florida, which is always equal to or greater in UV intensity than in Southern California.
- The covering is considered sunlight resistant if the original to aged tensile and elongation ratio 80% or greater after the 720 hours of exposure. Additionally, because the covering is grey, the amount of UV absorption will be limited.

Significance

- Testing ensures that the strength of the covering is still at least 80% of the original strength before accelerated UV exposure
- Overall, UV testing requirement ensures the longevity of the covering

3. Environmental Stress-Cracking

This section describes the requirements of Environmental Stress-Cracking Testing.

Definitions

- Stress-Crack – An external or internal rupture in a plastic caused by tensile stresses less than its short-time mechanical strength

Environmental Stress-Cracking Testing

- ICEA S-121-733-2016 does not require Environmental Stress-Cracking Resistance for 90ºC rated covered conductor because the covering material is inherently resistant to Environmental Stress-Cracking
- Environmental Stress-Cracking is the development of cracks in the material due to low tensile stress and environmental conditions. Under certain conditions of stress with the presence of contaminants like soaps, wetting agents, oils, and detergents, ethylene material may exhibit mechanical failure by cracking.

Significance

- Having a 90ºC Rated covered conductor means that the covering will be inherently resistant to cracking under conditions of stress and in the presence of contaminants

4. Track Resistance

This section describes the requirements of the track resistance testing.

Definitions

- Electrical Erosion – The progressive wearing away of electrical insulation by the action of electrical discharges
- Track – A partially conducting path of localized deterioration on the surface of an insulating material
- Tracking – The process that produces tracks as a result of the action of electrical discharges on or close to the insulation surface
- Tracking Resistance – A quantitative expression of the voltage and the time required to develop a track under specified conditions

Track Resistance Testing

- SCE requires conformance to ICEA S-121-733-2016 Track Resistant Testing
- Track resistance testing will evaluate the tracking and erosion resistance of the covering and its effects upon the insulation.
- During this test, the covering is exposed to a conducting liquid contaminant at an optimum rate, in a manner that allows continuous electrical discharge to be maintained.
- The effects are similar to those that may occur in service under the influence of dirt combined with moisture condensed from the atmosphere.
- Producing continuous surface discharge with controlled energy will mimic long-term exposure in the field in an accelerated time frame.
- For the sample to pass, the time to track one inch at 2.5 kV must be a minimum of 1000 minutes.

Significance

- Testing ensures that the covering is track resistance
- Track resistance properties will ensure insulation that electrical charges will not erode the insulation over time
- Overall, testing requirement ensures the longevity of the covering

5. Maximum Dielectric Constant

This section describes the maximum dielectric constant requirements

Definitions

- Dielectric Constant: a quantity measuring the ability of a substance to store electrical energy in an electric field
- Dielectric Strength: the maximum electric field that a pure material can withstand under ideal conditions without breaking down

Maximum Dielectric Constant

- The maximum dielectric constant must be 3.5, per ICEA standards
- The lower the dielectric constant, the higher the dielectric strength.

Significance

- Ensuring that the dielectric constant meets the requirements certifies that the insulation strength of the covering is acceptable and the covered conductor will perform as designed.

6. Production Testing

This section describes production testing requirements.

Production Testing

- SCE requires manufacturers to perform routine production testing
  - DC Resistance
    - The DC resistance on the conductor must not exceed 102% of the maximum allowable value
  - Unaged and Aged Tensile and Elongation
    - Tensile elongation is the stretching that a material undergoes. The point of rupture must be greater than 1800 psi for unaged samples. Samples are aged at 121°C for 168 hours. Aged samples must rupture at a minimum of 75% of the unaged value. This test validates the mechanical properties of the covering
  - Hot Creep
    - Hot creep tests validates that the covering is crosslinked, making it a thermoset. Thermosets can withstand higher temperatures and are less likely to deform at high temperatures.
  - Spark Test
    - Spark tests validates the integrity of the insulation. An electrical cloud is generated around the cable. Any pinholes or faults in the insulation will cause a grounding of the electrical field and this flow of current will register a defect in the insulation.
- Passing routine production tests ensures that the covered conductor deployed in SCE facilities meet industry standard and are high quality
- Passing ensures that the covering can perform as intended for a 45 year operating life

7. Covered Conductor Failure Mode

This section articulates the possible failure modes and provides a high-level analysis how the these impact on Covered Conductor at SCE, and finally what SCE has done to address these failure modes

Known Failure Modes

- Covered conductor could have burn down if not adequately designed or installed
- The following known issues are addressed either by design criteria or installation guideline
  - Electrical tracking on surface of covers
  - Arc generated from lightning strikes
  - Aeolian (Wind-Induced) Vibration
  - Premature Insulation Breakdown

Mitigating Against Electrical Tracking on Surface of Covers

- Electrical tracking occurs when carbon pathways (tracks) form on the surface of an insulating material, which could lead to breakdown
- SCE will only procure CC that has completed extensive qualification testing to industry standards (UV Resistance, Environmental Cracking, and Track Resistance)
- Early material that suffer from tracking issues are crosslinked polyethylene with high carbon content for UV inhibiting purposes
    - SCE specified material using cross-linked high density polyethylene with little carbon black. Titanium Dioxide is used as a UV inhibitor.
- Early design of CC specify thin layers of insulation (less than 100 mils)
    - Covered conductor SCE will used has 150 mils of insulation

Arc Generated During Lightning Strikes

- During lightning strikes, an arc could form on the transition from covered to bare conductor, or where there are stripped or open point in the covered conductor
- Direct lightning strike on covered conductor would be more damaging than bare conductor because lightning moves more freely on bare conductors (to look for a path to earth)
- However, SCE is well prepared to mitigate this known issue for several reasons:
    1. SCE service territory is considered low lightning area
    2. Covered conductor is generally less “attractive” to lightning than bare conductor (insulating materials reduces electric field on the surface of covered conductor)
    3. SCE uses the most effective mitigation tool for lightning strikes
- Mitigating Lightning Failure
    1. Industry uses Arc Protection devices (APD’s), Power Arc Devices (PAD’s) and Lightning Arrestors (LA’s) for mitigating lightning strike failures
    2. Lightning Arrestor is the most well-built and effective device of all three
    3. SCE uses Lightning Arrestors and bolster the standards for covered conductor systems to be treated as high lightning area
    4. SCE’s high lightning standards require Lightning Arrestors to be installed in all equipment poles (all transformer sizes, capacitor, RAR, switch, voltage regulator, etc.)
    5. SCE standards requires Lightning Arrestors to be installed in covered conductor to underground transitions
    6. SCE will minimize stripping and removal of the covering
    7. SCE standards require stripped or uncovered portions will be covered (i.e. splice)

CONCLUSION: SCE is well positioned for protecting covered conductors from lightning because direct strikes on covered conductors are less likely at SCE’s territory, but if it happens, damage due to lightning may be mitigated by Lightning Arrestors, i.e. direct to ground instead of stuck on one covered location, or covered to bare transition or flash over to other phases.

Aeolian (Wind Induced) Vibration

- Wind induced vibration of conductors could lead to fatigue failure of the conductor (similar to bending a piece of wire back and forward until it break) High conductor tensions lead to Aeolian vibration issues
- Mitigating Aeolian Vibration
  - SCE developed proper sag and tension values for covered conductor
  - SCE's tension limits are in line with Northeast Utilities that have an 80% covered conductor system.
  - The Northeast utilities indicated that they have not experienced problems due to Aeolian vibration

Premature Insulation Breakdown

- Wear and tear could lead to premature insulation breakdown
  - Insulation breakdown will equate effectiveness of covered conductor to bare
  - Result from improper installation or constant abrasion from vegetation
- Mitigating premature insulation breakdown
  - Outer covering is a high density material, and is resistant to incidental abrasion
  - Discussion with other utilities indicated that older covered conductor design performed as intended even after 50 years
  - Construction standard requires care during installation and handling of the covered conductor

Learning from Past Experience

- SCE has performed literature research, talked to industry experts, visited utilities and suppliers, and employed consultants to inform the design and installation of covered conductor to withstand early known issues
- Based on past performance in various utilities and the robustness of the current covered conductor design, Engineering fully expect the covered conductor to perform for at least 45 years without issues

Chapter III
Industry Benchmarking and Research

1. Benchmarking

Utility Benchmark Questionnaire

- Sent out survey questionnaire to utilities to learn about covered conductor standards, application and performance:
    - Seattle City Light (Washington)
    - Puget Sound Energy (Washington)
    - Con Edison (New York)
    - Orange and Rockland Utilities (New York)
- Learned about downed wires with covered conductor
    - In Early 1980s, Con Ed experienced plenty of burn downs
        - Failures were at dead ends and equipment leads
        - Failures were at bare to covered transitions
    - Orange and Rockland found that protective relays will trip during a burn down
- Failure modes of covered conductor
    - Nicked conductor during stripping
    - Prolonged incidental contact (months)
- Cable type and Size
    - Seattle City Light and Puget Sound: 125 mils HDPE
    - Con Edison: 175 mils EPR
    - Orange and Rockland: 40-80 mils XLPE
- Voltage
    - Seattle City Light: 7.2 kV
    - Con Edison:
        - 27 kV – Mostly CC
        - 4-14 kV – CC

Round Table Benchmark with Northeast Utilities

- Conducted an in-person discussion on covered conductor experience with the Northeast utilities:
  - Hendrix (manufacturer), Liberty Utilities (New Hampshire), Groveland Light (Massachusetts), Holyoke (Massachusetts), Middleton (Massachusetts).
  - Past standards engineer of Eversource attended as well
- Covered Conductor Systems
  - New England overall is approximately 80% Covered Conductor and 20% Bare
- End of life
  - Covered conductor still looks and performs the same after 50+ years of service
- Issues
  - Manufacturing problems due to ring cuts was experienced in the late 70s before cleanrooms
  - Corona is main failure mode (phase to ground through tree), but it takes years to fail
  - None has experienced Aeolian vibration issues
  - None has encountered water ingress
- Lightning
  - Burn down happens at stripped portion
  - Add lightning arrestors at equipment, transitions to bare, and dead-ends
  - Had enough incidents to decide to install lightning arresters at end of line
  - All advise not to install lightning arresters at every 1000 ft. Avoid stripping as much as possible.

Global Research

- Global information was gathered from covered conductor research literature as well as government and utility publications.
- Future Benchmarking Plans:
  - SCE will contact Australian utilities directly to gather more information about their Bushfire Mitigation Plans
  - SCE will conduct a round table discussion with South Korea's utility Korean Electric Power Corporation (KEPCO) to learn more about construction best practices and understand the reasoning behind their deployment of covered conductor.

Global Research – Australia (Historical Installations)

- Covered Conductor has been used in Australia for over 50 years
- Early installations experienced the following problems:
  - Initial coverings of PVS, HDPE, and nylon gave very limited lifetimes and suffered surface degradation.
  - Initial installations were subject to failure due to lightning damage
- In the late 1980s, Australia reconsidered Covered Conductor for safety considerations (human and wildlife), conductor clashing, tree problems, and bushfire mitigation.
  - However, within 2 years of installation, it was found that the covered conductor was incapable of handling anything more than momentary contact
  - Other problems include severe RF emissions and tracking
- In the mid 2000s research for the Australian Strategic Technology Program illustrated that technological advancements and solutions to historical issues regarding covered conductors exist, which may allow for a widespread adoption of covered conductors in Australia

Global Research - Australia

- In 2009, the Victorian Bushfires Royal Commission (VBRC), which was established in 2009 by the government after the devastating Black Saturday bushfires, recommended the following:
  - The progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
  - The progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.
- Progress of VBRC recommendation implementation:
  - 2010 – Established a Bushfire Powerline Safety Taskforce (BPST) to recommend to the Victorian Government how to maximize the value to Victorians from the VBRC recommendations.
  - 2011 – The Bushfire Powerline Safety Taskforce recommended the following:
    - The BPST recommended to target SWER and 22kV powerlines in the next 10 years
    - The BPST recommended that any new powerlines built in areas targeted for replacement should also be built with underground or covered conductor
    - Estimated a 90% reduction in the likelihood of a bushfire starting by installing covered conductors
    - Recommendations were accepted by the Minster for Energy and Resources on December 29, 2011
    - AUS $750 million Powerline Bushfire Safety program was announced by the Victorian Government
  - 2012 – Areas of highest bushfire risk for purposes of asset installation were identified and a detailed forward works program was developed
  - 2013 – A brief focusing on the first five years of the program, described in more detail the complexities of delivering the substantial set of reforms and provided concise project planning, management, and delivery structure.
  - 2014 – Installation of first replacement powerline in high bushfire risk areas
  - **2016 – Amendments were made to the Electricity Safety (Bushfire Mitigation) Regulations which specify the use of covered conductors or undergrounding for any new or rebuilt circuits in high bushfire risk areas**
    - **The Victorian Government's Powerline Replacement Fund makes available up to $200 million to electrical distribution businesses and private land owners to replace bare wire powerlines**

Global Research – Australia

- Utility Implementations of VBRC Recommendations
  - Ausnet
    - Victorian utilities to use either insulated or covered conductor for any planned conductor replacement of more than 4 spans of 1kV-22kV line (within codified areas)
    - For AusNet, the codified areas included approximately 1,000 miles of bare wire, medium voltage powerlines. **They began replacing line in this area in 2014 relying on an established $200M Powerline Replacement Fund (PRF)**
    - AusNet is progressively replacing the remaining bare wire in codified areas outside of PRF activities because of the cost associated with insulated/covered conductors
    - **Construction of any new medium voltage electric line that is part of the supply network must use insulated cable or covered conductor**
  - Powercor
    - Per their 2016 Bushfire Mitigation Plan, Powercor is implementing underground cable/overhead covered conductor when construction either 22kV, single wire earth return (SWER) or low voltage assets for all new construction and the same Electrical Safety (Bushfire Mitigation) Regulations listed for AusNet reconductoring activities
- Utilities outside of Victoria
  - Energy Queensland
    - 2017 Summer Preparedness Plans target installation of covered conductor in bushfire risk areas.
  - Essential Energy
    - Bushfire Risk Management Plan (Issue 13, 2017) was provided to meet the objectives and requirements of the NSW Electricity Supply (Safety and Network) Regulation 2014, which includes a provision for the review of equipment types or construction methods known in their operation or design to have bush fire ignition potential and a mitigation strategy in relation to their use
    - Plan calls for use of underground cable and covered conductor on overhead primary, promoting underground or insulated low voltage lines in rural areas, and identifying at-risk private low voltage lines on customer properties and undergrounding or replacing with CCT

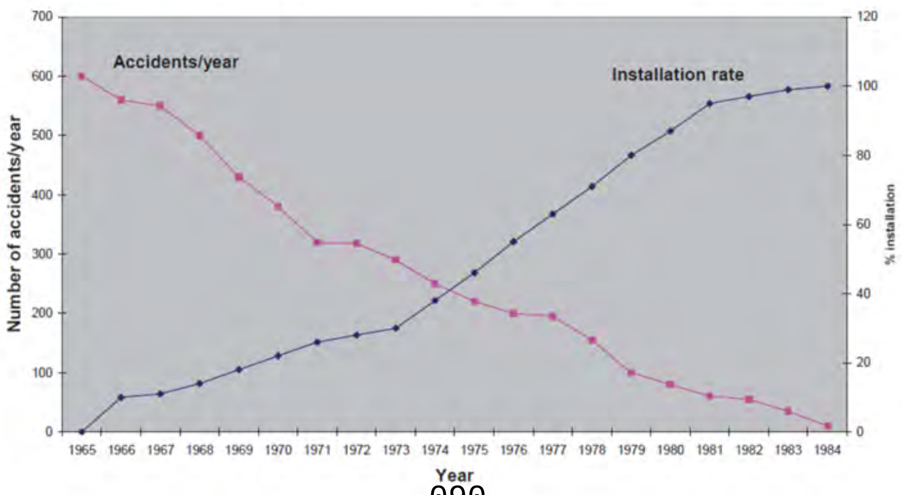
Global Research - Europe

- United Kingdom
  - The UK started installing covered conductors in 1994
  - The typical close spacing and compact construction prompted the first use of covered conductors in the UK
  - As of 2005, UK has installed 9,300 circuit miles of covered conductor
- Finland
  - Finland installed the first installations of covered conductors in Europe.
  - Main impetus for research into covered conductors in the 1970s was the reduction of forest fires caused by trees falling on bare overhead lines.
  - As of 2005, Finland installed approximately 3,100 miles of covered conductor.
  - 60% of new construction and refurbishment schemes use covered conductor
- Sweden
  - Covered Conductor was first introduced in Sweden in 1984.
  - First installation was in a snowy and high wind area to reduce faults due to snow-laden branches resting on the line and wire slapping
  - As of 2005, Sweden installed approximately 2,500 miles of covered conductor
  - 60% of new construction and refurbishment schemes use covered conductor

Global Research - Asia

- South Korea
  - Extensive CC use by Korea Electric Power Corporation (KEPCO) for 23 years
  - Covered Conductors make up 96% of South Korea’s low voltage and medium voltage distribution line
  - Use CC Tested to 25 kV
- Japan
  - Started using covered conductors in 1965
  - Driving force behind CC installation is to reduce the number of accidents and fatalities due to bare OH lines and improve reliability

Reduction in electrical accidents against CC installation rate



2. Industry Surveys

Background

- SCE requested members of the following groups to participate in a survey about covered conductors
  - Edison Electrical Institute (EEI)
  - Western Underground Committee (WUC)
  - The Association of Edison Illuminating Companies (AEIC)
- A total of 36 utilities participated.

Summary

- Bare wire is the standard.
  - On average bare wire makes up 88% of a utility's distribution system
- 28% of participants indicated that they use covered conductors on primary distribution lines.
- 33% of participants indicated that they historically used covered conductors, but no longer use them on new installations
- Most utilities indicated that covered conductor is used to prevent vegetation contact
- Most utilities indicated that the benefit of using covered conductor is less contact related faults

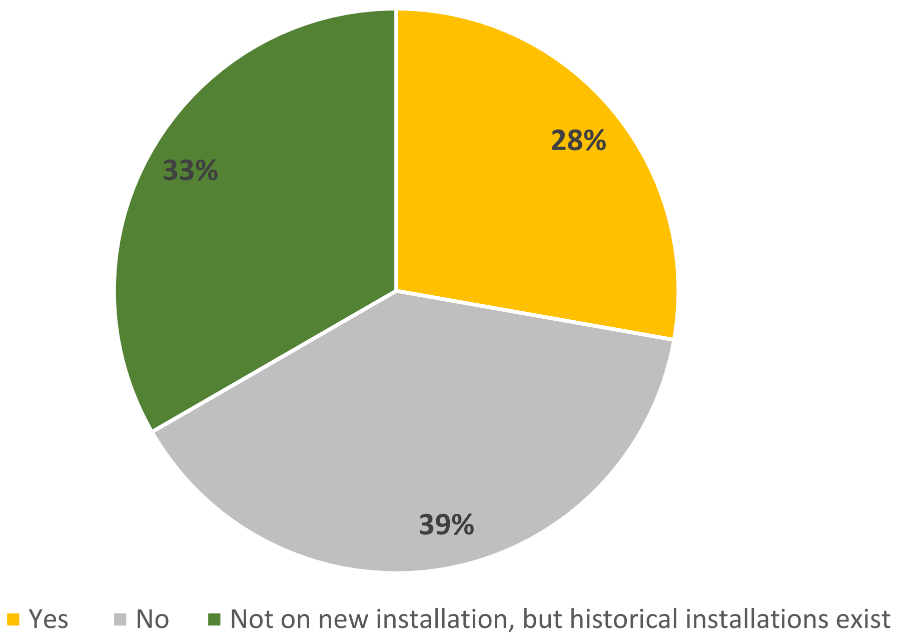
List of Participants

1	AES
2	Alliant Energy
3	Ameren
4	American Electric Power
5	Anonymous Participant
6	CenterPoint Energy
7	City of Banning
8	City of Lodi
9	City of Mesa Energy Resources
10	City of Richland, WA
11	City of Roseville
12	Con Edison
13	Dominion Energy
14	DTE Energy
15	Duke
16	FirstEnergy
17	Florida Power & Light
18	Idaho Power
19	Kansas City Power and Light

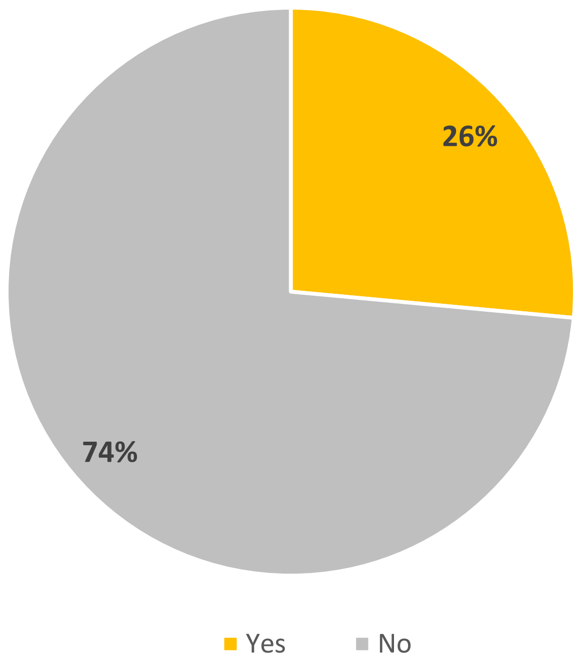
20	LADWP
21	LG&E and KU Energy
22	Midwest Energy, Inc.
23	National Grid
24	Northern Indiana Public Service Co.
25	Northwestern Energy
26	Oklahoma Gas & Electric
27	Oncor Electric Delivery
28	Orange & Rockland
29	Puget Sound Energy
30	Sacramento Municipality Utility Distrct
31	Salt River Project
32	Snohomish PUD
33	Southern Company
34	Tampa Electric
35	Tucson Electric Power
36	Westar Energy

Covered Conductor Usage

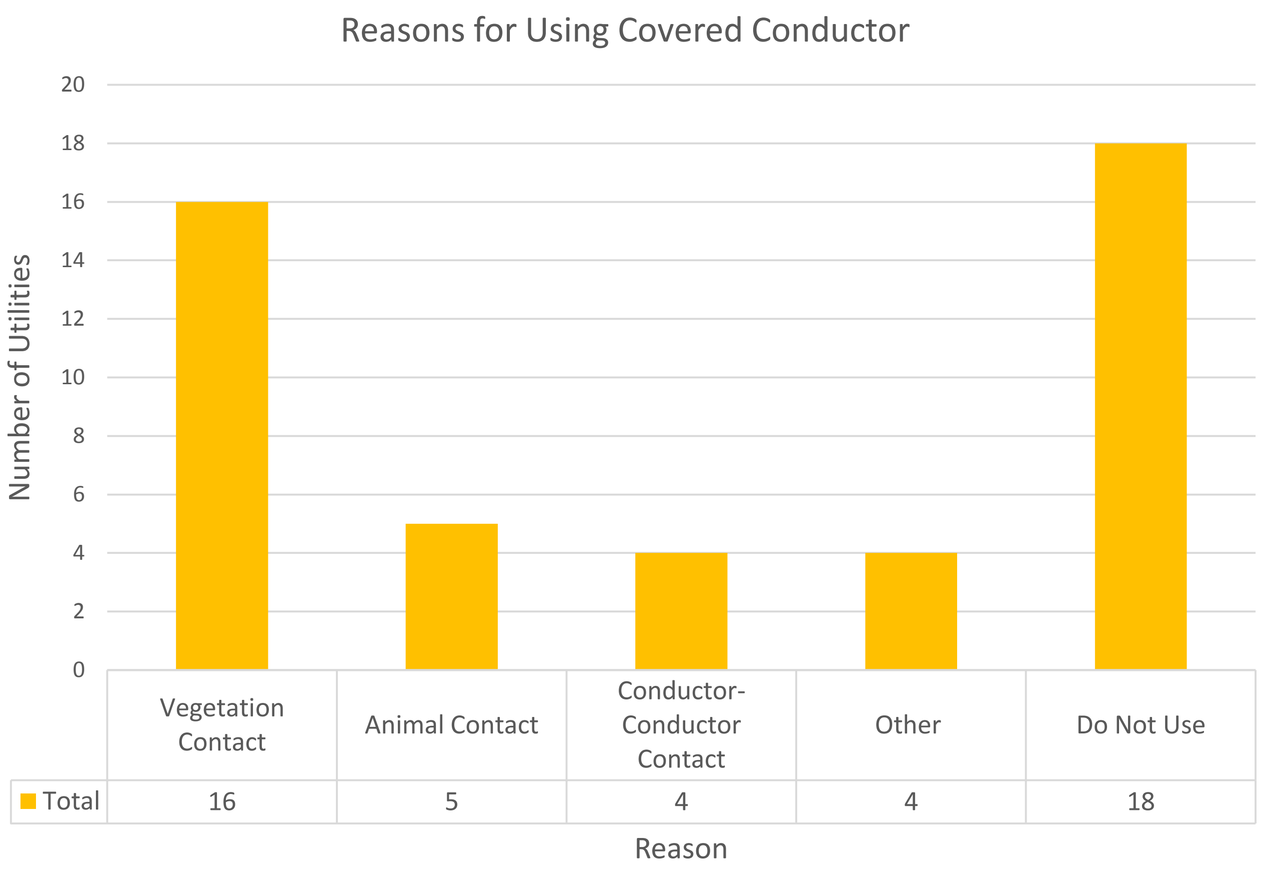
- Do you install covered conductor (Tree wire) for your primary (4 kV or higher) distribution lines?



- Do you install covered conductor (tree wire) for your branch line primary distribution wire? (fused, radial, two phases or less)



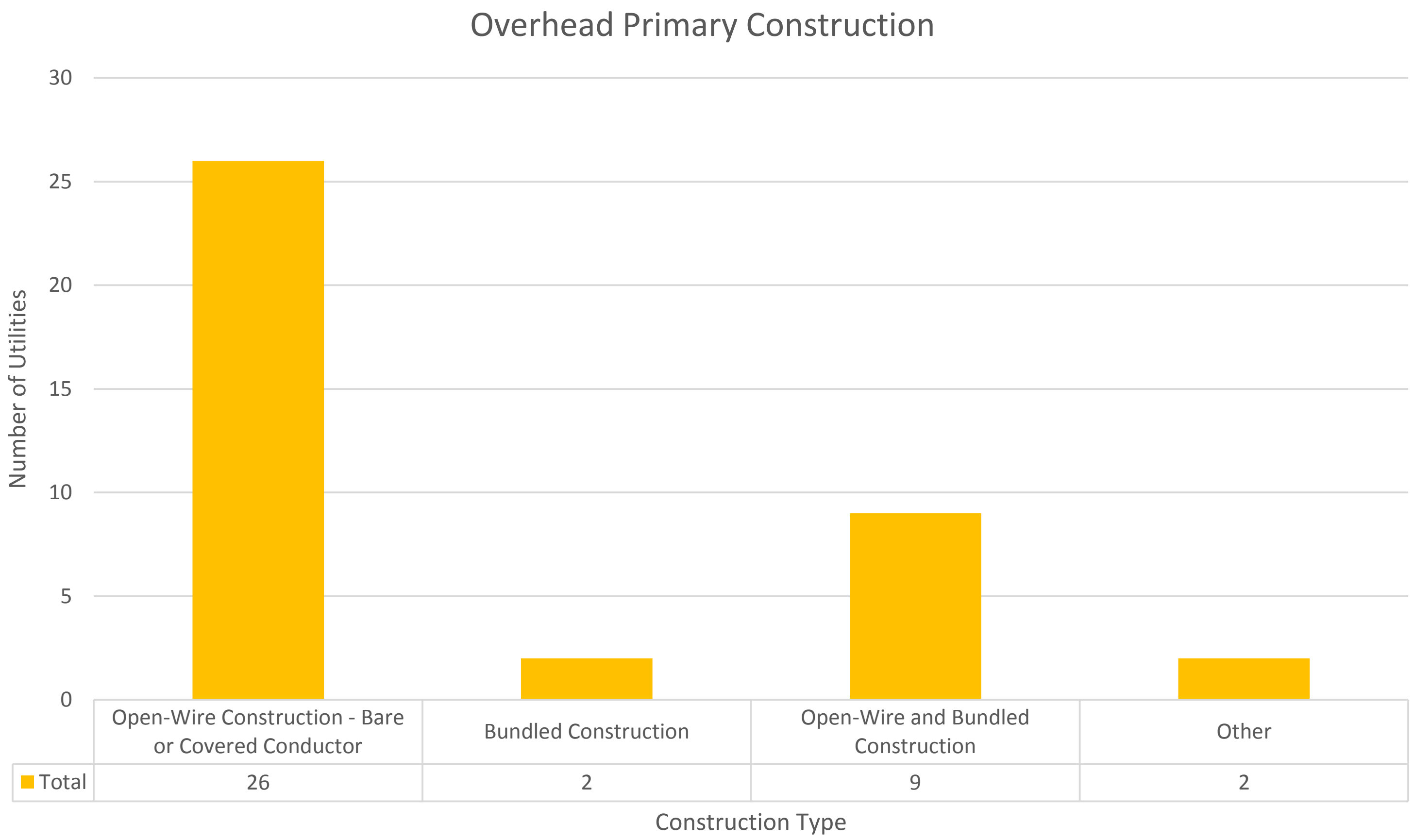
Reasons for Using Covered Conductor



Other

- Clearance and space management
- Higher density of circuit routing on a single pole

Types of Overhead Primary Construction Used

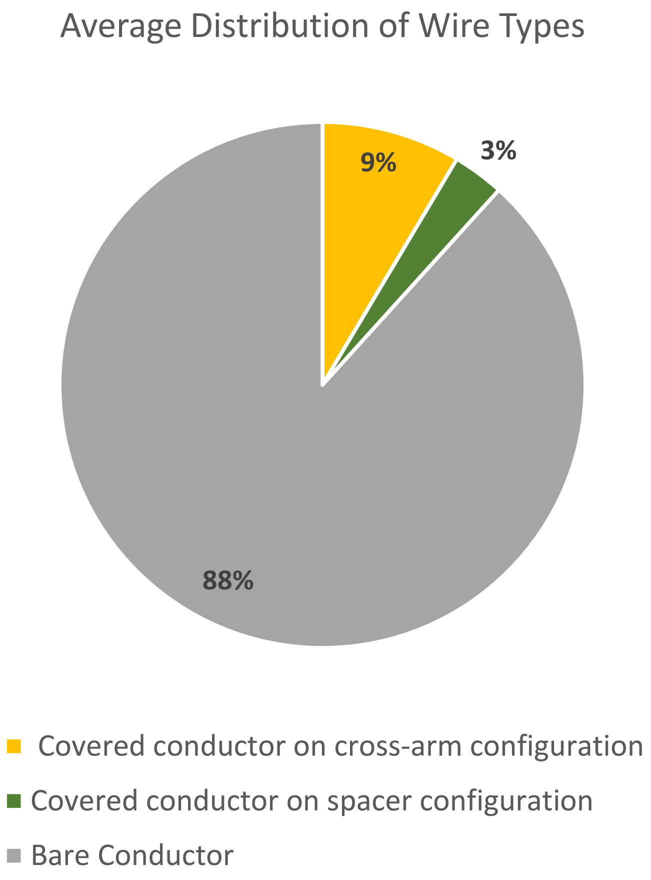


- Other
  - Armless Construction
- Open-wire can mean vertical or horizontal construction

Construction Criteria

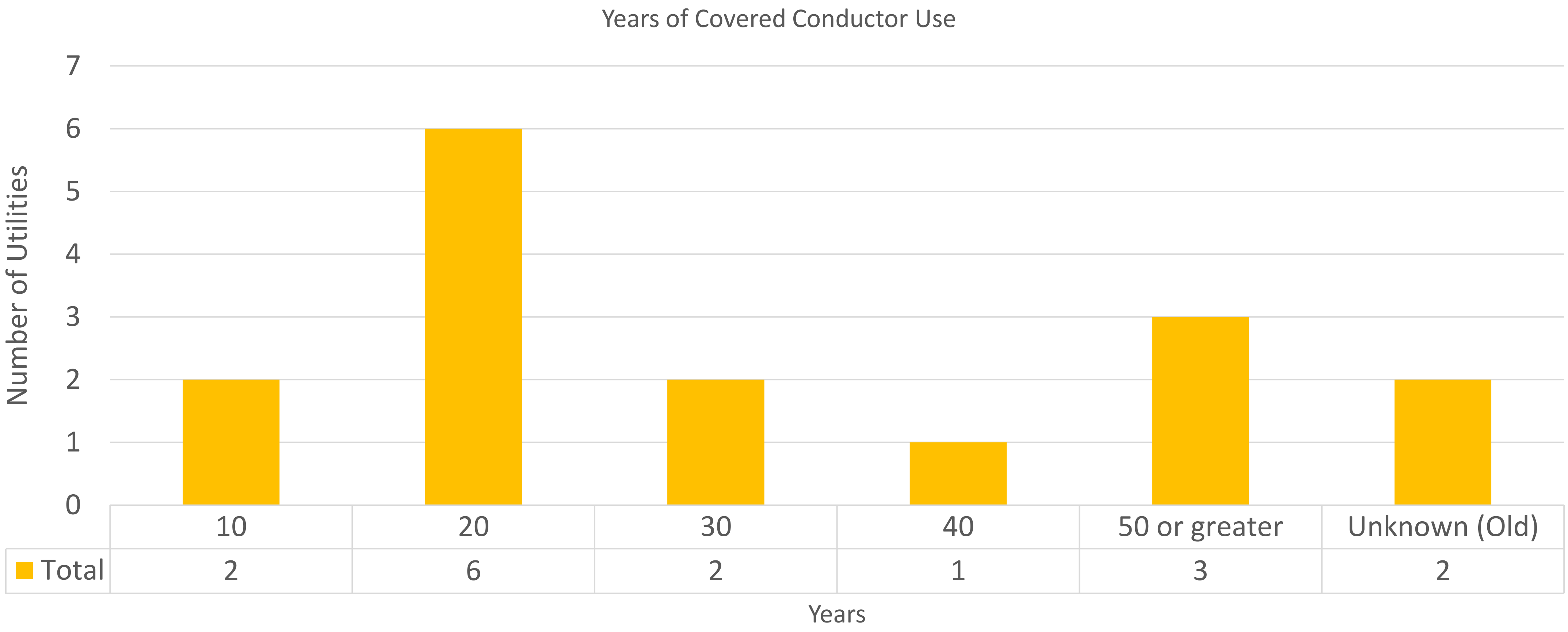
- Utilities typically use bundled construction in limited scenarios, which can include the following:
  - Use in areas in lieu of underground due to difficult trenching conditions
  - Express or dedicated feeders with limited or no taps
  - Limited right of way space
  - Heavily treed areas with tight clearances
  - Multiple circuits on a single pole
  - Storm hardening

Distribution of Various Wire Types



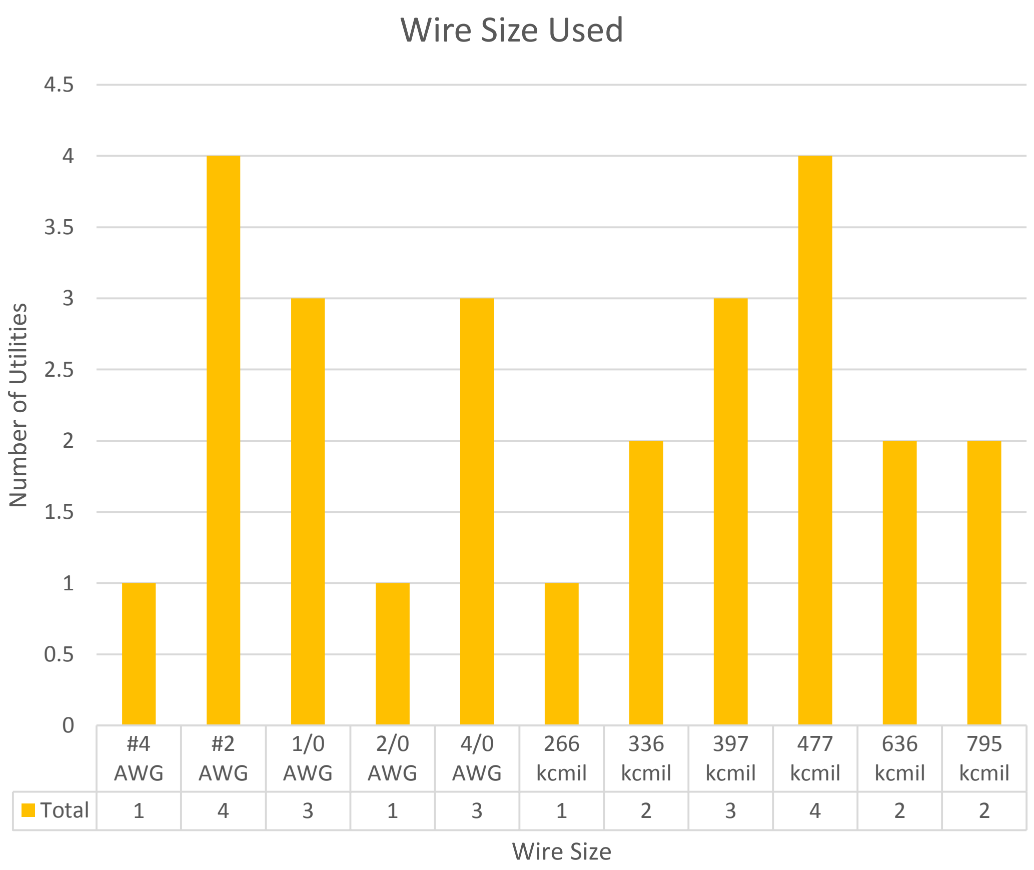
- On average, a utility's distribution system is made up of
  - 88% Bare Wire
  - 9% Covered Conductor on cross-arm configuration
  - 3% Covered Conductor on spacer configuration

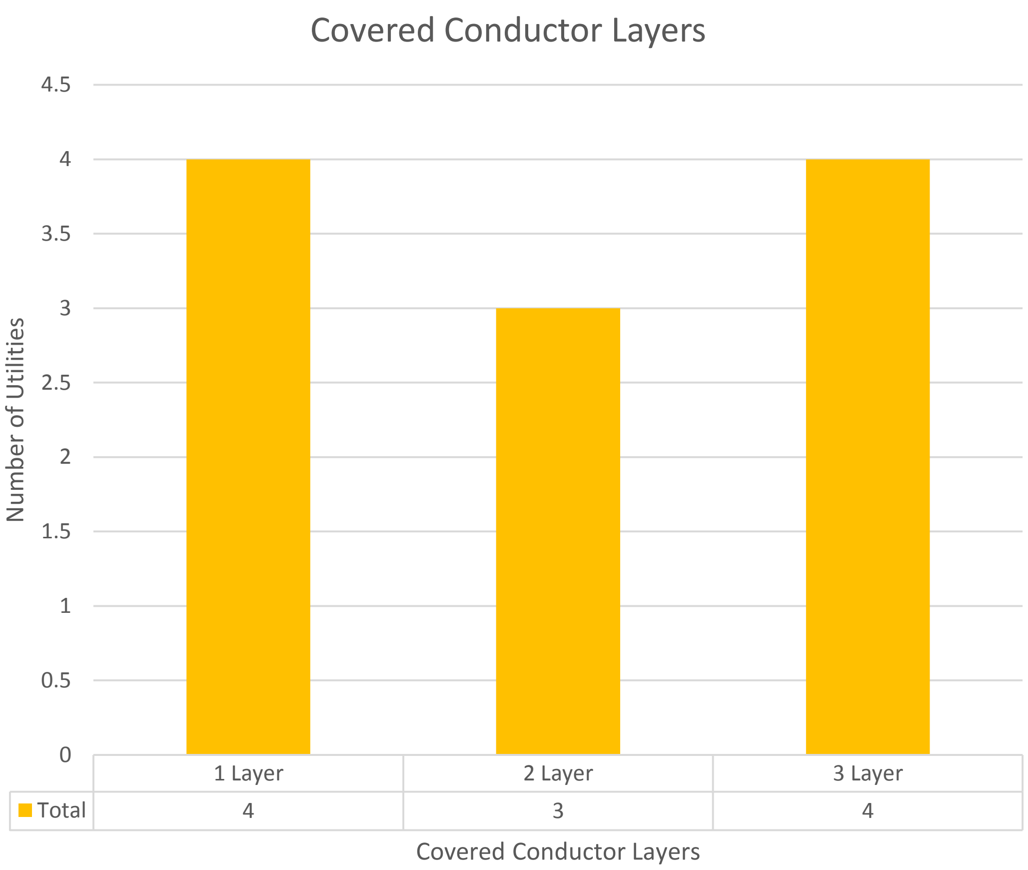
Years of Covered Conductor Use



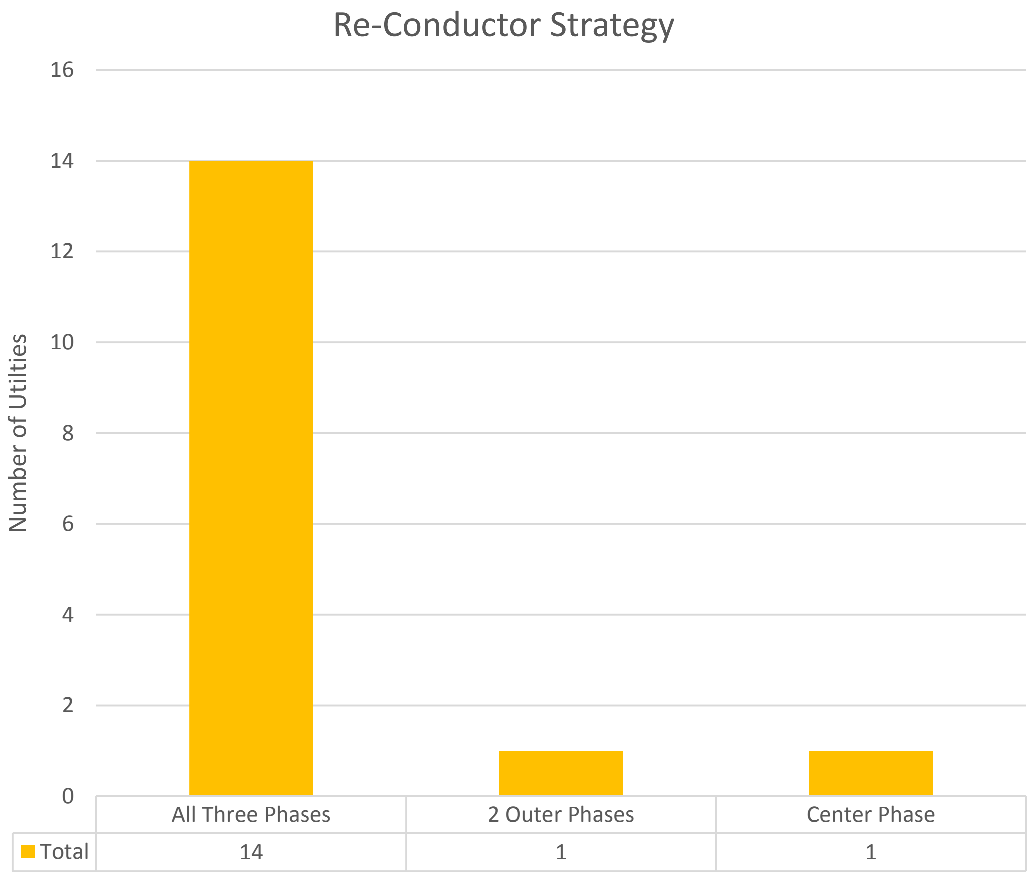
	10	20	30	40	50 or greater	Unknown (Old)
Total	2	6	2	1	3	2

Covered Conductor Wire Sizes and Layers



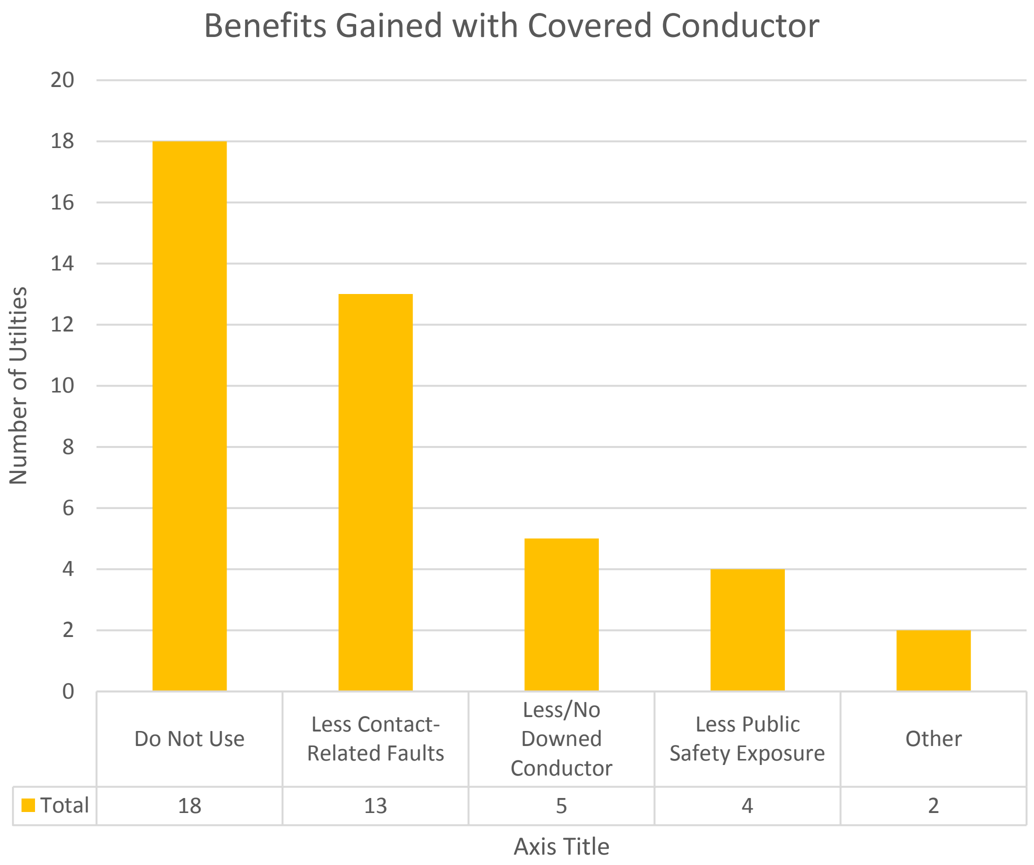


Re-conductoring Main Line



- All utilities indicated that they re-conductor all three phases when moving from bare wire to covered conductor
- One utility indicated that a standard does not exist and therefore performs all three options when re-conductoring to covered conductor:
  - All Three Phases
  - Two Outer Phases Only
  - Center Phase Only

Benefits Gained with Covered Conductor



- Other:
  - Utilities that answered "Other" indicated covered conductor caused more problems such as more downed conductor however, this experience is based on historical covered conductor systems (from 20 years ago or more).

3. Incorporating Lessons Learned

Known Challenges

The following challenges associated with covered conductor have been identified via research and benchmarking:

1. Aeolian Vibration
2. Abrasion
3. Electrical Withstand
4. Lightning Protection
5. Corrosion
6. Tracking
7. Burn Down
8. Wire Down Detection
9. Radio Frequency

Incorporating Lessons Learned

1. **Aeolian Vibration Limits**
   - Sag and Tensions for the covered conductor will take into account the terrain. There will be two separate tables for light and heavy loading. The loading limits account for wind and ice.
2. **Abrasion**
   - SCE's Covered Conductor design uses a Crosslinked High Density Polyethylene layer to help resist abrasion. Additionally, covered conductor must be handled with care in order to prevent damage to the covering.
3. **Electrical Withstand**
   - SCE uses a triple sheathed covered conductor design, which has been found to be the best choice for long term electrical withstand for trees and with adjacent phases. BIL of SCE's CC is 200 kV.
4. **Lightning Protection**
   - Surge arresters will be installed at all overhead equipment locations and at UG Dips.

Incorporating Lessons Learned

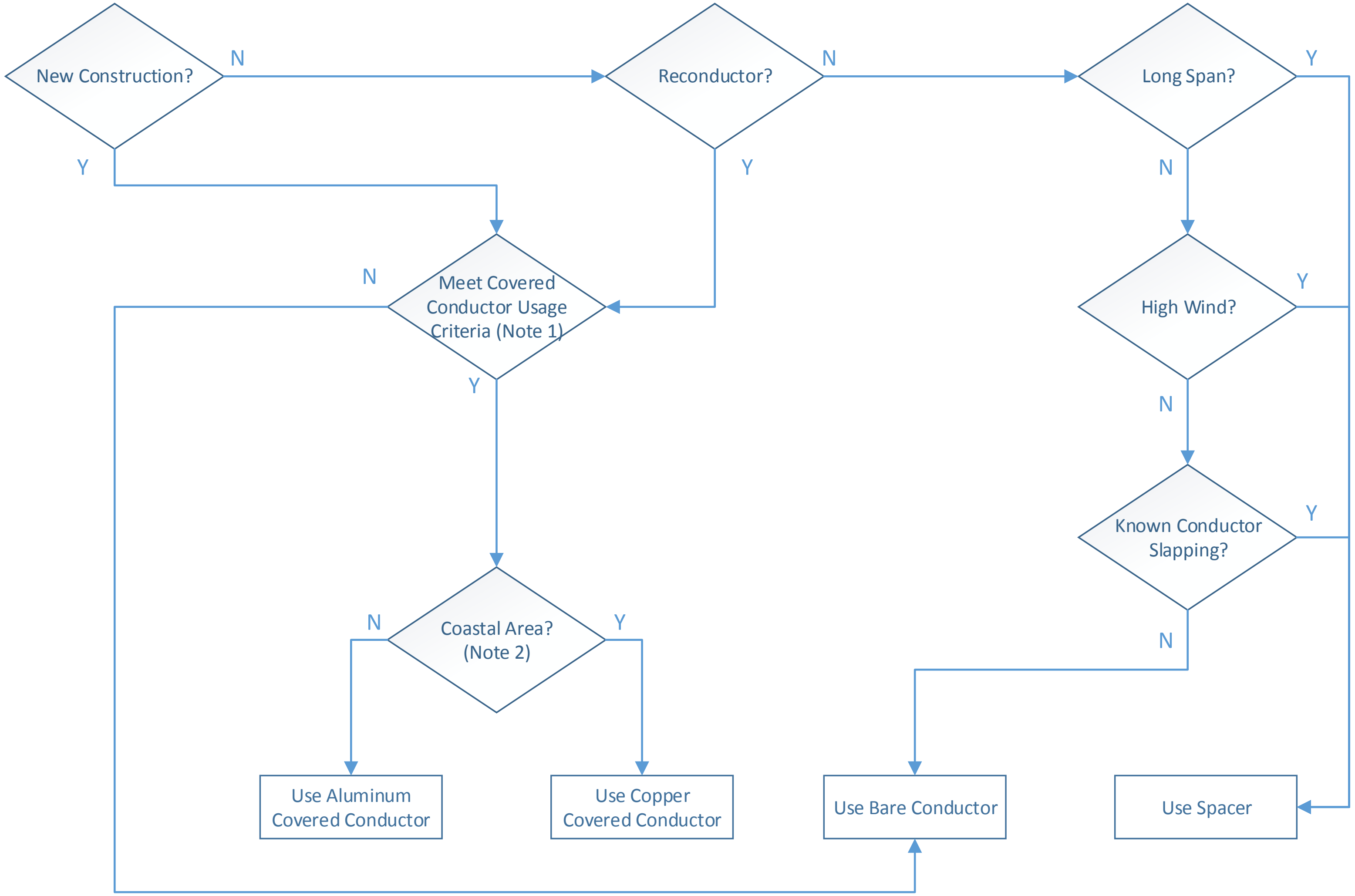
5. **Corrosion**
   - SCE will be using copper covered conductors in coastal applications.
6. **Tracking**
   - SCE's covered conductor design will include a track resistant XLPE outer layer. Additionally, SCE will mitigate tracking by using polymeric insulators, using crimped connectors, and using a low carbon content sheath.
7. **Burn Down of CC**
   - SCE will incorporate the following to prevent burn downs.
     - Suitable lightning protection (installation of surge arresters)
     - Reducing electrical stresses and carbon content on sheath material (polymeric insulator, low carbon XLPE, etc.)
     - Correct installation and tensioning (Sag and Tension will take into account terrain such as wind loading and ice)
     - Tree Trimming (SCE will maintain tree trimming requirements)
8. **Detection of Downed CC**
   - SCE will use SEF method of protection for covered conductors, which is the same protection scheme for bare wire.
9. **Radio Frequency Concerns**
   - SCE will use low carbon black content sheaths and polymeric insulators to significantly reduced tracking, thus reducing RF problem in coastal area.

Chapter IV
Covered Conductor Construction

1. Covered Conductor Installation Guideline

This section discusses the covered conductor installation criteria

Installation Guideline



- New Construction and reconstruction in High Fire Areas will require covered conductor
- Reconductor will be triggered by other programs, such as OCP

- Note 1: See Next Slide for Usage Criteria
- Note 2: Coastal Area is defined as area within one mile of the coast

Covered Conductor Usage Criteria

1. System Operating Bulletin 322 Areas (HFRA)
2. Heavy vegetation with potential tree and palm frond contact
3. Known metallic balloon contact causing circuit outages
4. Any area with outages due to known intermittent contact
5. Coastal areas within one mile of the ocean
6. Any specific area that experiences accelerated corrosion

2. Covered Conductor on Three Phases and Neutral

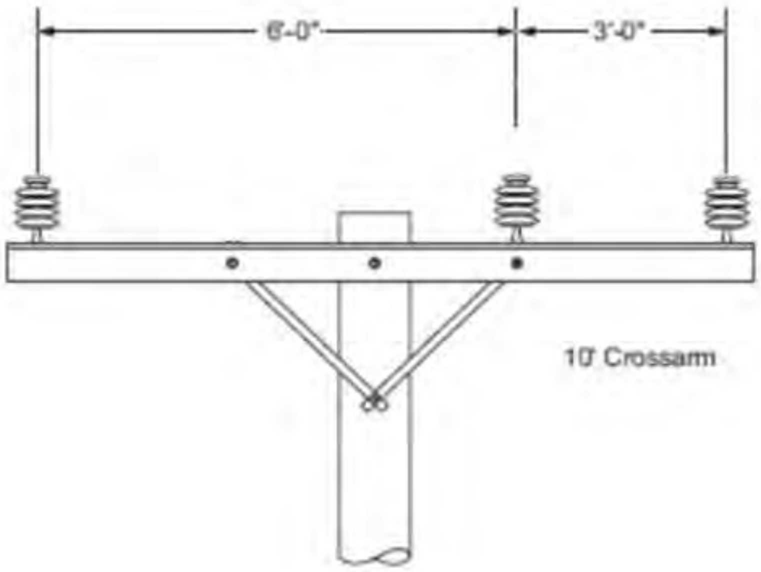
This section discusses the key factors considered to select covering all phases in SCE Standards

SCE Standards: Covered Conductor on Three Phases and Neutral

- Covered conductor will be used on all three phases in three-wire overhead system (mostly mainline)
- Covered conductor will be used on all two phases in overhead branch lines
- Covered conductor will be used on the neutral wire in four-wire overhead system (20% of SCE system has a neutral wire)

Analysis Factors

- Phase Spacing is key for the covered conductor
- This analysis will assume a three phase system. Refer to the figure below for phase spacing distances on a composite crossarm.



Evaluation of 1 Phase Covered

- In this configuration, it is assumed that only Phase B will be covered. Phase A and C will be bare wire.
- Analysis of effectiveness for mitigating phase to ground contact
  - This configuration will not be effective in preventing phase to ground contact. Phase A or Phase C will be susceptible to incidental contact with trees, therefore not eliminating the risk of a phase to ground fault.
- Analysis of effectiveness for mitigating phase to phase contact
  - This configuration will not be effective for phase to phase contact. There is 9 inches between the bare Phase A and Phase C. A foreign object or wildlife that is long enough could cause phase to phase contact. Palm fronds can be up to 13 feet long and California Condors have wingspans that are up to 10 ft long, which is enough to cause a phase to phase fault.
- Analysis of fire mitigation effectiveness
  - Covered conductor is considered effective for fire mitigation due to its ability to prevent incidental contact. However, its ability to prevent incidental contact will be compromised if the only one phase is covered.
  - Additionally, downed conductor is still possible due to mechanical failures or other equipment failure. The probability of a bare wire igniting a fire is higher than if it was covered.

2 Phase Covered

- In this configuration, it is assumed that Phase A and Phase C will be covered. Phase B will be bare wire.
- Analysis of effectiveness for mitigating phase to ground contact
  - This configuration will not be effective in preventing phase to ground contact. While the probability of a phase to ground contact is lower because Phase A and Phase C will be covered, Phase B will still be susceptible to incidental contact with trees, which will lead to a phase to ground fault.
  - Additionally, some equipment, such as transformers may be within 6 feet from the phases. Phase to ground faults may be possible due to incidental contact between the equipment and the center phase.
- Analysis of effectiveness for mitigating phase to phase contact
  - Because Phase A and Phase C are covered, the probability of phase to phase contact is reduced.
  - Internal SCE studies have shown that current through an object, such as a tree limb, connecting two phases of covered conductor is about 0.2 mA. This value doubles to 0.4 mA if the object is connecting a bare wire and covered conductor.
  - Insulation degradation on the covered conductor will happen at a faster rate, leading to failure happening at a faster rate.
- Analysis of fire mitigation effectiveness
  - The fire mitigation effectiveness is still less than if the system was fully covered. Phase to ground incidental contact is still possible even with two phases covered, leading to arcing that could cause ignition.
  - Furthermore, downed conductor is still possible due to mechanical failure or other equipment failure. The probability of a bare wire igniting a fire is higher than if it was covered.

Evaluation of 3 Phases Covered

- In this configuration, it is assumed that Phase A, Phase B, and Phase C will be covered.
- Analysis of effectiveness for mitigating phase to ground contact
  - Because the system is fully covered, there is a very low probability of incidental contact causing phase to ground faults.
- Analysis of effectiveness for mitigating phase to phase contact
  - Because the system is fully covered, there is a very low likelihood of incidental contact causing phase to phase faults.
- Analysis of fire mitigation effectiveness
  - Covered conductor is considered effective for fire mitigation due to its ability to prevent incidental contact. By fully covering all three phases, the possibility of faults due to incidental contact is greatly reduced.
  - If a downed wire scenario were to happen, covered conductors are less likely to cause a spark that bare wire. Therefore, the chance of ignition has been greatly reduced.

Neutral Covered

- In this configuration, it is assumed that Phase A, Phase B, Phase C and the Neutral will be covered.
- Analysis of effectiveness for mitigating phase to neutral contact
  - Because the system is fully covered, there is a very minute likelihood of incidental contact causing phase to phase faults.
- Analysis of fire mitigation effectiveness
  - In a downed wire scenario, a covered neutral will be less likely to cause a spark than a bare neutral.
  - Chance of ignition is reduced

Other Factors to consider

- Sagging
  - Covered conductor and bare wire are sagged at different tensions
  - If covered conductors were to be sagged like bare wire, it may cause vibration problems
  - Covered conductors have more sag than bare
  - Mixing bare and covered conductor in one crossarm will cause uneven sags
  - Uneven sags may increase the risk of conductor slapping, leading to an increased chance of insulation degradation, arcing, and ignition.
- Benchmark
  - Other utilities use a 3 phase covered system

Conclusion

- Partially covering the system (1 phase covered, 2 phase covered, bare neutral) will dilute the effectiveness of covered conductor.
- Using covered conductor for all three phases and the neutral promotes SCE's grid resiliency and the elimination of an ignition source.

3. SCE Covered Conductor Construction

This section illustrates how Covered Conductor and Wildlife Covers being used in SCE Standards to achieve maximum protection from incidental contacts

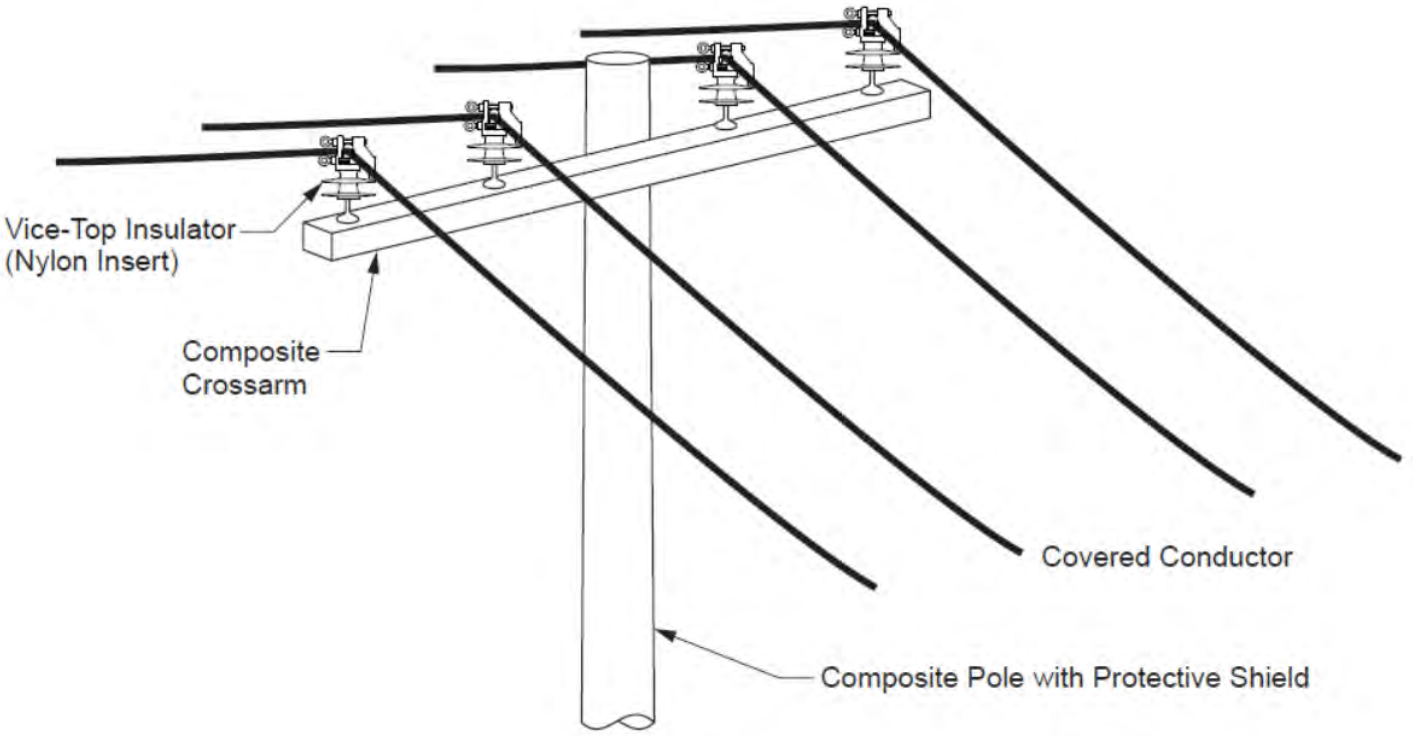
SCE Construction Diagrams

- SCE’s covered conductor systems will be all covered
- This includes wildlife covers on dead-ends, terminations, and equipment bushings, jumper wires
- Also illustrated are other Wildfire resilient equipment/hardware, such as composite pole, composite cross-arm, polymer insulator for covered conductor
- These illustrations depict the four common pole configurations:
  - Tangent pole: means covered conductor pass thru insulators
  - Dead-end pole: covered conductor will stripped off to connect to dead-end insulator
  - Transformer pole: stripping cover required for connecting to transformer (or equipment)
  - Riser pole: stripping cover required to connecting to underground cable

Tangent 4 Wire Construction

Tangent pole does not need other covering hardware

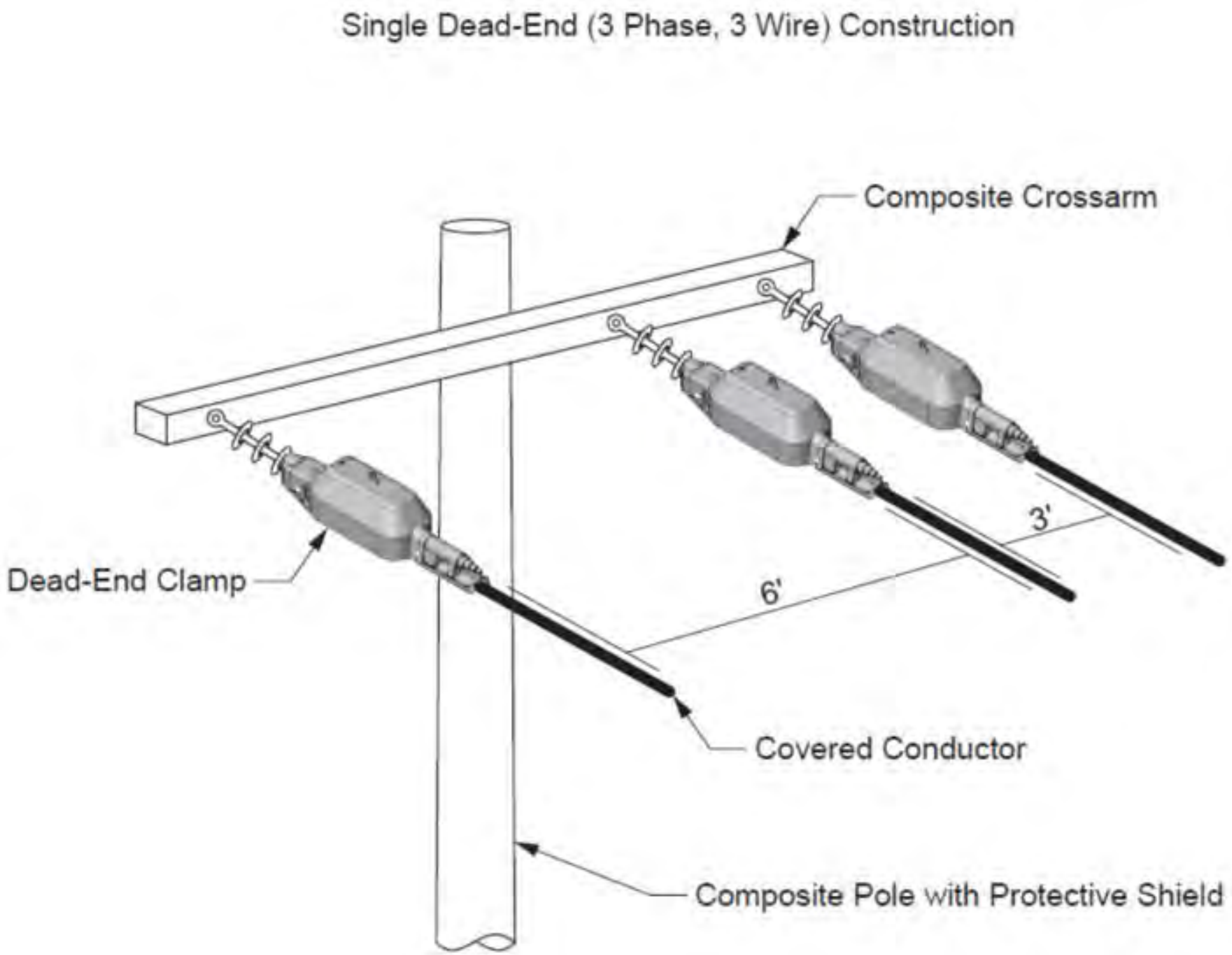
3 Phase, 4 Wire Tangent (Straight-Line) Construction



Same concept for three-wire and two-wire constructions

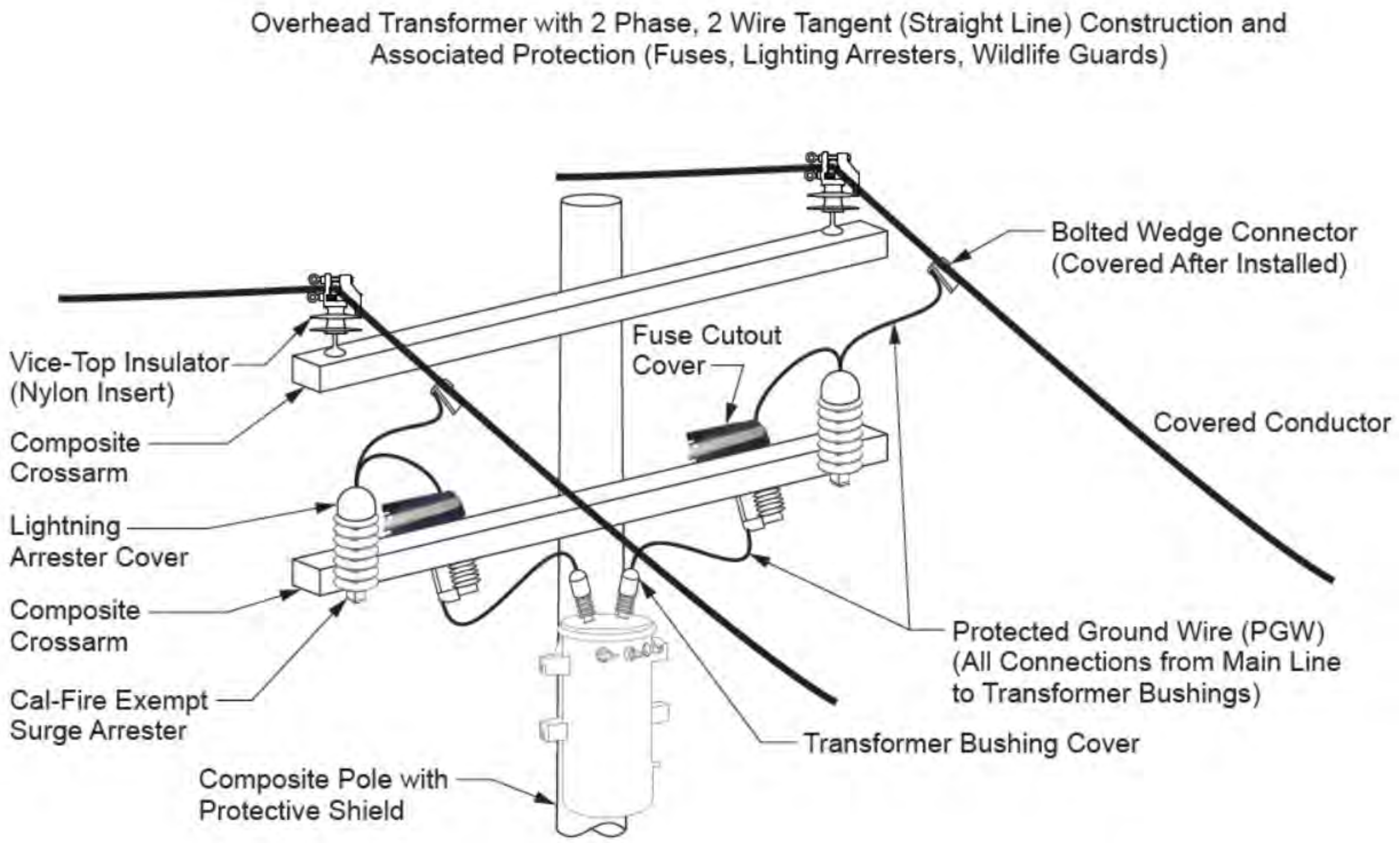
Three-wire Dead-end Construction

Introduce new standards for dead-end cover, composite pole and cross-arm



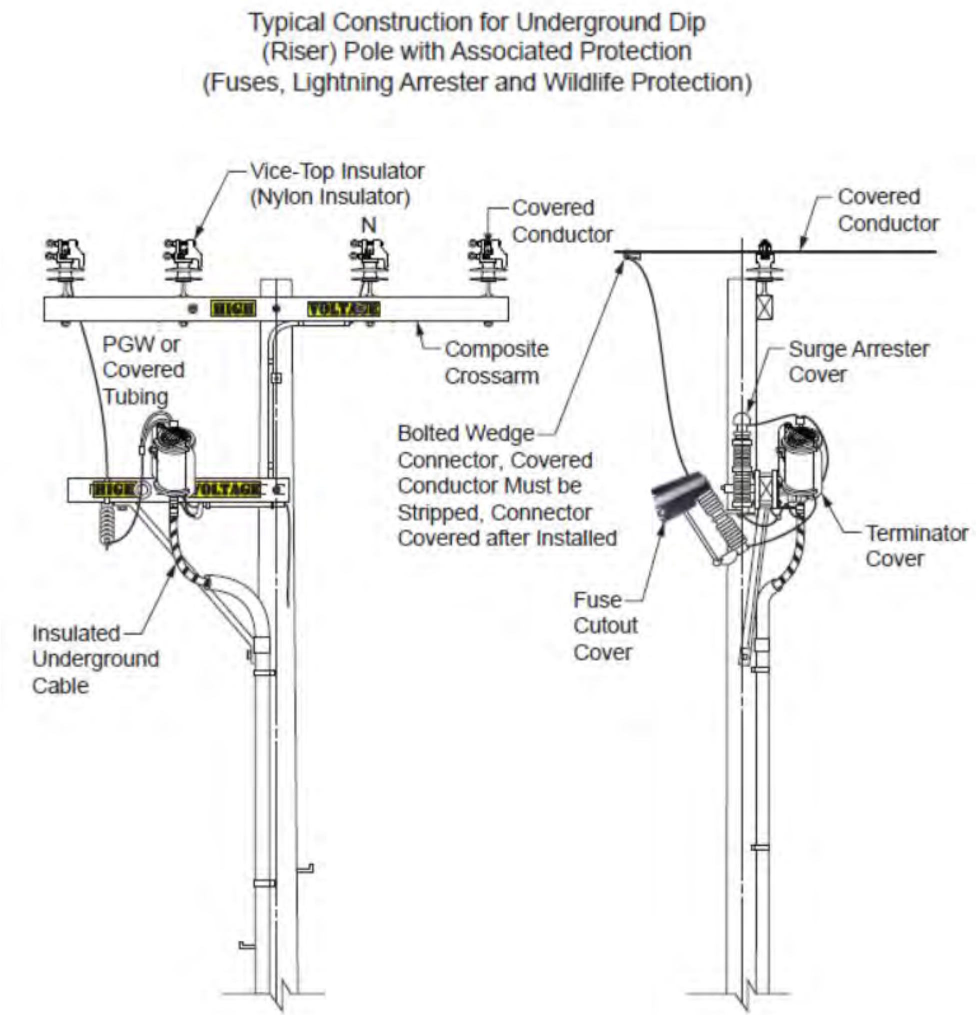
Same concept for four-wire and two-wire constructions

Tangent 2 Wire with Transformer Construction



Same concept for connecting to other equipment: capacitor, switch, remote automatic recloser, etc.

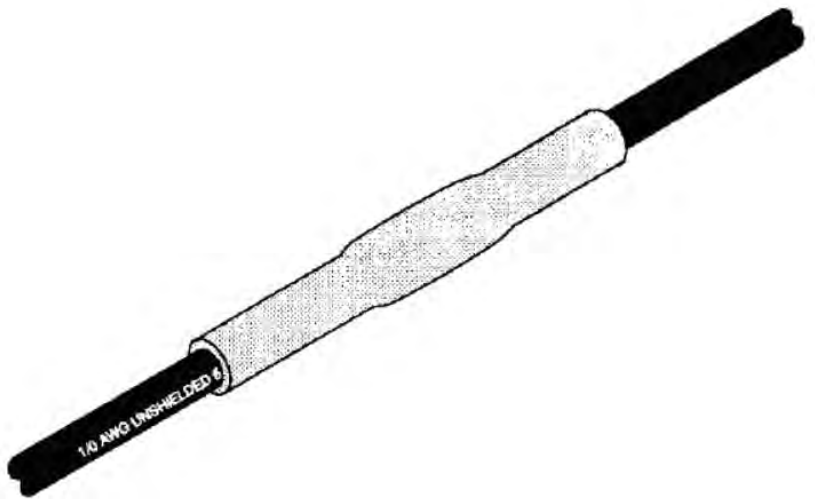
Riser Pole Construction



Same concept for three-wire and two-wire constructions

Splices

- Splices will be covered
- Splices for adjacent conductors shall not be installed next to each other and should be staggered 18 inches end to end.



Question 11: On page 81 of testimony, footnote 105, SCE describes vendor documentation regarding “high magnitude fault currents.” What power flow constitutes “high magnitude?” Do typical phase-to-phase or phase-to-ground fault currents for the voltages identified in Question 6 above achieve this level of current?

Response to Question 11:

The “high magnitude” is referencing a theoretical amperage for a current limiting fuse to operate in current limiting mode. The amperage is theoretical because the design of the current limiting fuse reduces the actual magnitude of current. Current limiting mode for a fuse varies based on manufacturers and fuse size; however, 40 times the fuse rating is a reasonable approximation for the minimum threshold for a fuse to operate in current limiting mode. SCE deploys fuses ranging from 12A to 100A.

SCE fault currents can exceed 20,000A, but are commonly in the range of 1,000A to 10,000A for phase-to-phase or phase-to-ground faults on many parts of the distribution circuits in question. Typical fault currents on the SCE system will cause current limiting fuses to operate in the current limiting mode.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET CalPa-SCE-006

To: Cal PA
Prepared by: Brian Chen
Job Title: Senior Advisor
Received Date: 1/31/2019

Response Date: 2/21/2019

Question 01: Question 1
What quantifiable improvements (i.e. metric improvements) does SCE expect to see on circuits or in areas treated through its covered conductor program? What quantifiable improvements does it expect to see system- or region-wide?

Response to Question 01:
Please refer to SCE's 2019 Wildfire Mitigation Plan (WMP), filed on Feb. 6, 2019, that includes specific covered conductor goals and metrics to evaluate SCE's Wildfire Covered Conductor Program (WCCP) performance. The WMP also includes indicators to evaluate information over time and reflect the long-term outcomes that the WCCP (and other wildfire mitigation programs/activities) are intended to influence. Cumulatively, the success of SCE's programs and activities in its WMP (including WCCP) are expected to result in an overall reduction of controllable fire ignition events in HFRA over time.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C a l P a - S C E - 0 0 6

To: Cal PA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 1/31/2019

Response Date: 2/21/2019

Question 03: Question 3
Does SCE have any specific plans as to how it could or will modify its implementation of its covered conductor program based on the effectiveness measurements described in Question 02? If so, please describe.

Response to Question 03:

Given the significant amount of covered conductor under the WCCP and the wildfire risk mitigation benefits the program provides, SCE will endeavor to accelerate the installation of covered conductor in HFRA. Additionally, SCE is assessing expanding the WCCP to deploy covered conductor across all of Tier 3 HFRA over multiple years starting in 2019. SCE will continue to monitor the effectiveness of its mitigation measures and adjust accordingly. This could be a combination of either engineering and/or design changes or adjustment to the deployment rate of the various mitigation measures as SCE gathers data over time. As SCE noted in its Wildfire Mitigation Plan at page 96, SCE's ability to measure the effectiveness of its wildfire mitigation programs will require years of observation in HFRA to develop a complete viewpoint.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET CalPa-SCE-006

To: Cal PA
Prepared by: Thuan Tran
Job Title: Senior Advisor
Received Date: 1/31/2019

Response Date: 2/21/2019

Question 02: Question 2
How will SCE quantitatively measure the effectiveness of its GSRP (for example, what metrics will be gathered regarding ignitions or maintenance requirements)? How will this data be reported to the Commission?

Response to Question 02:
Please refer to SCE's 2019 Wildfire Mitigation Plan, filed on Feb. 6, 2019, that includes activities, goals and metrics for all of SCE's wildfire mitigation strategies and programs including its 2019 GRSP activities. SCE will continue to track and report "reportable ignitions" to the CPUC pursuant to D.14-02-015. SCE will also continue to provide inspection and maintenance reports to the CPUC pursuant to the requirements set forth in GO 95, 128, 165 and 174. Additionally, pursuant to Public Utilities Code Section 8386, SCE will file a report with the CPUC addressing SCE's substantial compliance with its 2019 WMP by March 31, 2020.

Southern California Edison
A.18-09-002 Grid Safety & Resiliency Program

DATA REQUEST SET C a l P a - S C E - 0 0 4

To: CalPa
Prepared by: Hunly Chy
Title: Manager Dated: 1/4/2019

Question 07: Has SCE studied differences in restoration and troubleshooting times for covered conductor vs. bare conductor? If so, please provide such studies and any related/underlying data

Response to Question 07:

SCE is in the process of studying troubleshooting for covered conductor. However, covered conductor construction requirements, such as the need to strip the covering to make connections and the need to ensure wildlife coverings are installed, will likely lead to longer restoration times that may offset reduced outages associated with avoided faults due to covered conductor. SCE will not have data until its study is completed.

Southern California Edison
A.18-09-002 Grid Safety & Resiliency Program

DATA REQUEST SET C a l P a - S C E - 0 0 4

To: CalPa
Prepared by: Brian Chen
Title: Principal Manager Dated: 1/8/2019

Question 02: Has SCE applied or does SCE plan on applying any other fire-related treatments to the areas targeted for covered conductor installation, aside from those described in this application? If so, please describe. For the purposes of this question, please define treatments to mean actions separate from regular maintenance or repairs.

Response to Question 02:
SCE objects to this question as it requests information outside the scope of this proceeding. Notwithstanding and subject to its objection, SCE responds that it is conducting expanded infrastructure and equipment inspections in high fire risk areas throughout its territory and continues to explore other potential mitigation measures. At present, SCE is not implementing any other enhanced fire mitigation measures; however, it continues to evaluate other measures including alternatives considered in its Grid Safety and Resiliency Program (GSRP) filing and its Risk Asset and Mitigation Phase (RAMP) filing (I.18-11-006). SCE will continue to evaluate any additional mitigations as it gains new information which will inform any future determinations regarding further hardening of its infrastructure.

Southern California Edison
A.18-09-002 Grid Safety & Resiliency Program

DATA REQUEST SET C a l P a - S C E - 0 0 4

To: CalPa
Prepared by: Ryanne N Spady
Title: Senior Advisor Dated: 12/28/2018

Question 05: Are SCE's six covered conductor projects designed to cover specific circuits, a specific geographic area, or some combination of the two? Please describe.

Response to Question 05:
SCE assumes the six covered conductor projects referred to in this question is regarding the 592 circuit miles identified to be re-conductored with covered conductor in Section (IV)(B)(1) of SCE-01A-Amended (A. 18-09-002) (which encompasses more than six circuits). SCE selected this scope based on its circuit prioritization methodology detailed in its supporting "Circuit Deployment Prioritization" work paper submitted in support of SCE-01A (A. 18-09-002) on September 26, 2018. As explained in this work paper, SCE prioritized covered conductor deployment on circuits posing the greatest wildfire risk, focusing on ignition consequence and ignition frequency. SCE's prioritization methodology also took into account the mitigation effectiveness of covered conductor deployed in certain high fire risk areas.

SCE's forecasting methodology for determining the proposed scope estimate for the nine circuits selected is detailed in SCE's "Scope - Covered Conductor (Amended)" work paper submitted in support of SCE-01A (A. 18-09-002) on December 26, 2018. This workpaper also identifies estimated circuit miles by circuit.

Southern California Edison
A.18-09-002 Grid Safety & Resiliency Program

DATA REQUEST SET CalPa-SCE-004

To: CalPa
Prepared by: Andrew Garcia
Title: Senior Manager   Dated: 1/4/2019

Question 10: To what extent will the installation or replacement of fuses overlap with SCE's covered conductor program as proposed in this application? For example, will the two programs treat entirely distinct areas, entirely the same areas, or have some (but not complete) overlap? If the two programs will have some (but not complete) overlap, please quantify.

Response to Question 10:

SCE's current limiting fuses are complementary to its wildfire covered conductor program. There is "overlap" in the sense that the current limiting fuses (CLFs) will be deployed in high fire risk areas (HFRA) that will also be subject to deployment of covered conductor. Once fully deployed (i.e., beyond SCE's GSRP proposal), SCE's wildfire covered conductor program (WCCP) is expected to cover approximately 40% of primary overhead distribution lines located in HFRA, whereas the GSRP fusing program is intended to be deployed over 100% of these lines.

However, it is important to note that these programs do not overlap in terms of their respective strategic purposes for mitigating wildfire risk. Specifically, SCE's Wildfire Covered Conductor Program (WCCP), as explained in Section (IV)(B)(1)(pages 40-70) of SCE-01A (A.18-09-002) is preventative in nature and is intended to reduce the number of "contact from object" faults experienced such as wire-to-wire, vegetation, animal, and other debris. Due to the higher cost and relatively long lead times necessary to engineer, design, and construct covered conductor projects, SCE is selectively deploying covered conductor in areas where it will result in the greatest risk reduction. By comparison, SCE is deploying CLFs in order to minimize ignition risk by significantly reducing fault energy delivered to faults (i.e., after a fault event has occurred). SCE's overhead system is made up of approximately 43% mainline and 57% branch lines so installing fuses on all branch lines within the HFRA will provide a significant risk reduction value and can be realized for a relatively low cost and short timeframe.

Additionally, WCCP reconductoring design standards require installation of fuses for branch lines in order to protect the new conductor from damage that may be caused by faults covered conductor is not designed to prevent (e.g., a failed underground conductor or surge arrestors downstream of the branch line). These fuses will be installed either by WCCP or the fusing mitigation program, depending on which program reaches an area first (the majority should be done via the fusing mitigation program, however).

Southern California Edison

A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 5

To: CALPA
Prepared by: Andrew Garcia
Job Title: Senior Manager
Received Date: 1/15/2019

Response Date: 2/21/2019

Question 11: Question 11
To what extent will the installation or replacement of fuses overlap with SCE's covered conductor program as proposed in this application for the years 2018-2020? For example, will the two programs treat entirely distinct areas, entirely the same areas, or have some (but not complete) overlap? If the two programs will have some (but not complete) overlap, please quantify.

***Note: this question is similar to Question 10 of Data Request CalPA-DR-004, but clarifies that the covered conductor work referred to in this question refers to only the work performed in the years 2018-2020.

Response to Question 11:
SCE's current limiting fuses are complementary to its Wildfire Covered Conductor Program. The current limiting fuses (CLFs) will be deployed in high fire risk areas (HFRA) that will also be subject to deployment of covered conductor. During the 2018-2020 window, SCE's wildfire covered conductor program (WCCP) is expected to cover approximately 4.5% of its primary overhead distribution lines located in HFRA, whereas the GSRP fusing program is intended to be deployed over 100% of these lines.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 7

To: Cal PA
Prepared by: Thomas Brady
Job Title: Senior Manager
Received Date: 2/8/2019

Response Date: 3/11/2019

Question 06: Question 6
On page 95 of testimony, SCE states that it is “prioritizing circuits where these stations will be installed within HFRA by targeting locations in the downslope area of mountain ranges that would capture north-to-northeast winds.” Will the chosen locations represent coverage of varying conditions across HFRA? Please describe.

Response to Question 06:
Weather stations in the first year of the project were primarily chosen for north and northeast winds. For installations in 2019 and 2020, weather stations will be placed in a variety of areas that account for a different wind conditions including: onshore winds, offshore winds, Santa Ana Winds, and downslope winds.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Brian Chen
Title: Principal Manager
Dated: 09/28/2018

Question 03:

On pages 14-16 of its testimony, SCE discusses and illustrates fire risk areas in its service territory. Please provide a digital map, including any underlying metadata, of Figure II-2 (page 15) that is readable in ArcGIS or Google Earth.

Response to Question 03:

Attached is a kmz file that contains the following layers: (1) “SOUTHERN CALIFORNIA EDISON” which represents SCE’s service area boundaries; (2) “SCE T2” and “SCE T3” which represents CPUC Tier 2 and Tier 3 areas, respectively; (3) “T2 200ft Outer Buffer” and “T3 200ft Outer Buffer” which represents a buffer zone beyond the CPUC Tier areas SCE may use for operational convenience; and (3) “BL322” which represents areas designated as “SCE HFRA not in CPUC Tiers” in Figure II-2.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Rye Spady
Title: Senior Advisor
Dated: 09/28/2018

Question 11:

Please provide a map that is readable in ArcGIS or Google Earth, including any underlying metadata, of where SCE proposes to implement the covered conductor aspects of its GSRP.

Response to Question 11:

SCE has attached a .kmz file along with a Map Package that depicts where SCE proposes to implement covered conductor.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Thomas Brady
Title: Senior Advisor
Dated: 09/28/2018

Question 12:

Please provide a map that is readable in ArcGIS or Google Earth, including any underlying metadata, of where SCE proposes to install the HD Cameras.

Response to Question 12:

As discussed with Nils Stannik, Utilities Engineer for the Public Advocates Office, during a phone conversation held on September 28, 2018, SCE is responding to this request based on the HD camera locations identified to date. SCE expects seven additional locations will be identified by December 2018, with identification of another seventeen locations within the first quarter of 2019.

SCE Fire Management has partnered with the University of California, San Diego, local fire agencies, and tower owners to prioritize HD camera installations for the first 28 tower locations. SCE has attached a .kmz file and an excel Spreadsheet with metadata for these first 28 locations.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Cameron McPherson
Title: Senior Project Manager
Dated: 09/28/2018

Question 04:

Prior to the creation of the Commission's fire threat map, how did SCE determine or distinguish high fire risk areas

Response to Question 04:

Prior to the creation of the Commission’s Fire-Threat Maps and High Fire-Threat District (HFTD) map, SCE utilized CAL FIRE’s Fire Hazard Severity Zone (FHSZ) Maps developed under their Fire Resource and Assessment Program (FRAP).

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 5

To: 144
Prepared by: Brian Stonerock
Job Title: Principal Manager
Received Date: 1/15/2019

Response Date: 2/28/2019

Question 06: Will any SCE staff be reassigned (or have any staff been reassigned) from other work to implement the WCCP from 2018-2019 or from 2019-2020? If so, please generally describe what staff, what portion of their time was and will be spent on implementing WCCP, and what work this staff was performing before. For purposes of this question, an answer in categories or work types is acceptable (for example, "line workers" or "administrative personnel" vs. specific individuals or exact job titles).

Response to Question 06: SCE objects to this question on the grounds that it is vague, ambiguous, overbroad and unduly burdensome. Notwithstanding and subject to its objection, SCE responds that as a general matter it has adjusted and reprioritized workload assignments among many of its business units (Transmission and Distribution, Customer Service, Regulatory, Law, etc.) to support wildfire mitigation measures, including its WCCP, while continuing to support other utility programs and other matters. To the extent this question is asking if any of SCE's Distribution organization staff have been specifically reassigned to work exclusively on WCCP in 2018-2019, this is not the case, although WCCP is a critical focus within the organization and SCE's staff are generally working longer hours to accomplish this and other goals. At this time, however, there is no plan to have dedicated staff for WCCP. SCE's Distribution organization has engineers, planners, construction crews and many other people who support the WCCP work that also perform work on many other areas of the distribution system. SCE also relies on contract staff and is endeavoring to expand their capacity.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Ryanne Spady
Title: Senior Advisor
Dated: 09/28/2018

Question 14:

If SCE does not intend on using solely contractors for its covered conductor installation work, please describe the staff, teams, groups, or other parts of SCE's organization that will provide this work. Please provide staff's current responsibilities, previous/current experience installing covered conductor (or similar work) and number of personnel involved.

Response to Question 14:

SCE does not expect to solely use contract resources to design and install covered conductors; however, to the extent that existing SCE or contract resources are utilized to complete engineering, design, and / or construction activities, it will be necessary to hire additional SCE resources and / or additional contract resources to complete existing programs (e.g., Infrastructure Replacement, Preventative and Breakdown Maintenance, New Services Connections, etc.).

The groups that will be involved in this work will include engineering, design, electrical construction crews, project management, field accounting, and numerous support organizations.

Engineering resources, known as Field Engineers, develop the engineering studies to determine the appropriate engineering requirements such as conductor size and distribution protection requirements such as fuses. These engineers also develop engineering studies for load forecasting, load and generation interconnection to the distribution system, and other engineering studies for infrastructure replacement projects. The engineering studies required for covered conductor are consistent with studies performed for bare conductor installations. The number of resources required is estimated at 10 or more engineers through 2020.

Design resources, known as Planners, create designs for distribution capital work. These planners currently perform project management activities for the design of large tract developments, they design infrastructure replacement projects, perform pole loading, develop designs to connect new customers to the distribution system, and numerous customer requested designs for overhead to underground conversion, relocation of equipment, distribution energy resources interconnection, and many others. The designs for covered conductor are similar to the considerations required for bare conductor. The number of resources required is estimated at 40 or more planners through 2020.

Electrical construction resources, known as Electrical Crews, will construct the covered conductor work which is similar to the construction activities required for bare conductor installation. The differences include grounding reel tool safety work practice and stripping the cover off of the conductor to create electrical connections that these resources have been or are currently being trained on for the safe and efficient installation of this covered conductor. The number of resources required is estimated at 50 or more crews through 2020.

Other staff employees required to support this work includes material management, field accounting, scheduling, project management, and analytical resources. The number of resources required is estimated at 10 or more employees through 2020.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Ryanne Spady
Title: Senior Advisor
Dated: 09/28/2018

Question 13:

Does SCE now use or does SCE in the future anticipate using contractors to perform any aspects of covered conductor installation? If so, please describe what aspects and provide any cost comparison between the use of contractors and the use of SCE labor

Response to Question 13:

Yes. SCE intends to use contract resources, as well as SCE labor, to design and install covered conductors. Consistent with SCE's traditional work practices for a project of this size and scope, SCE will need to utilize a blend of contact resources and SCE labor to allow for operational flexibility and efficiency. The resource assumptions are available in SCE's "Unit Cost – Covered Conductor" work paper submitted in support of SCE-01A (A. 18-09-002) on September 26, 2018. SCE did not compare a purely SCE labor covered conductor unit cost to a purely contract resource covered conductor unit cost because the program will not be executed in this manner.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 5

To: Cal PA
Prepared by: Ryanne N Spady
Job Title: Senior Advisor
Received Date: 1/15/2019

Response Date: 2/26/2019

Question 07: Please describe how SCE plans to accomplish the 4.4-fold increase in circuit mileage reconductored from 2019 to 2020.

Response to Question 07:
SCE developed its WCCP scope for 2018 – 2020 to provide for the safe and efficient execution of the program. SCE established a "ramp up" period to allow for engineering studies, standards and work methods creation, establishment of vendors for new materials, and to all those vendors to ramp up for higher materials volumes than vendors have previous manufactured, instituting new quality control practices, and bringing on additional skilled resources. SCE projects that it will be able to meet the large increase in circuit mileage pursuant to its ramp up methods. Moreover, as discussed in SCE's Wildfire Mitigation Plan, SCE will endeavor to accelerate and expand its WCCP beginning in 2019.

Southern California Edison
SCE GS&RP A.18-09-002

DATA REQUEST SET A.18-09-002 CalPa-SCE-002

To: CAL PA
Prepared by: Randy Lisbin
Title: Principal Manager
Dated: 09/28/2018

Question 16:

On page 121 of its testimony, SCE discusses potential property owner opposition to tree removal and states that it "may need to provide replacement trees or other inducements on a case-by-case basis." a) Does SCE currently have a program and/or budget to provide such inducements? If so, please quantify and describe how this program works. b) Does SCE anticipate pursuing legal actions or court orders to facilitate removal of trees on privately-owned land? c) Does SCE anticipate offering cash payments, bill credits, or similar removal of trees on privately-owned land?

Response to Question 16:

a) **Does SCE currently have a program and/or budget to provide such inducements? If so, please quantify and describe how this program works.**

   SCE does not currently have a program and/or budget to provide inducements to property owners to remove trees that pose an expected threat to our facilities. On a limited, ad hoc basis, SCE currently provides a replacement tree to property owners who agree to remove trees that are typically fast growing species, in close proximity to SCE's facilities, and require multiple prunings a year to maintain mandated clearances. The costs of these replacement trees are included in the invoices from SCE's tree pruning contractors and are not separately tracked.

b) **Does SCE anticipate pursuing legal actions or court orders to facilitate removal of trees on privately-owned land?**

   Until SCE gains experience in the field, it is difficult to determine the level of property owner opposition and how best to overcome it. SCE is developing its process for overcoming property owner resistance and is currently exploring various approaches, including but not limited to legal action or court orders.

c) **Does SCE anticipate offering cash payments, bill credits, or similar to facilitate removal of trees on privately-owned land?**

   Until SCE gains experience in the field, it is difficult to determine the level of property owner opposition and how best to overcome it. SCE is not currently planning to offer cash payments or bill credits, but may seek to do so, if other inducements are not sufficient to overcome property owner opposition and conditions warrant enhanced actions.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C a l P A - S C E - 0 0 9

To: CalPA
Prepared by: Thomas Brady
Job Title: Senior Manager
Received Date: 3/21/2019

Response Date: 3/27/2019

Question 01: On page 92 of SCE's GSRP Testimony, it states:

"For 2018, SCE targets installing up to 70 PTZ cameras on approximately 35 towers, covering up to 50 percent of Tier 2 and 3 areas. These cameras will be installed on third-party towers and strategically placed in areas providing maximum visibility of HFRA. In 2019, SCE plans to install up to 70 additional PTZ cameras on another 35 tower locations, covering up to 80 percent of Tier 2 and 3 areas.

In 2020, SCE targets installing up to 20 cameras on 10 additional towers to bring coverage up to 90 percent of Tier 2 and 3 areas, and to increase resiliency by creating multiple backhaul pathways using the microwave network."

a) How many cameras were installed in 2018 and 2019 to date, respectively?

b) Based on current installation rates, does SCE still expect to have an approximate total of 160 HD cameras installed by the end of 2020? If not, please provide the new timeline as to when all cameras will be installed, and the reasoning for any changes in the timeline.

Response to Question 01:

a) In 2018, SCE installed 40 cameras. So far in 2019, SCE has installed 30 cameras on 15 towers, and expects to install 30 additional cameras by April 15th; bringing the total to 100 cameras.
b) Yes, SCE expects to have installed an approximate total of 160 HD cameras by the end of 2020.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 7

To: Cal PA
Prepared by: Thomas Brady
Job Title: Senior Manager
Received Date: 2/8/2019

Response Date: 3/15/2019

Question 17:
Have all new positions been filled? If not, please provide current status.

Response to Question 17:
SCE interprets this question as focusing on the four additional positions outlined in its GSRP filing (a Fire Scientist, a Fire Management Officer and two Meteorologists). To date, SCE has filled all four positions adding one Fire Management Officer, two Meteorologists and one Fire Scientist.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 7

To: Cal PA
Prepared by: Thomas Brady
Job Title: Senior Manager
Received Date: 2/8/2019

Response Date: 3/15/2019

Question 10:
With respect to SCE's proposed IBM Weather Modeling Tool (IBM Forecast on Demand System), SCE states that it "anticipates fully deploying it in production environment in 2018-19." (SCE Testimony, p. 98.)
a.Is the IBM Forecast on Demand System working and in use now?

Page 99 of SCE's testimony states that the next release of the weather monitoring software (IBM Forecast on Demand System) was scheduled for October 2018.

a. Was that release date met, and if so, were there any changes made as to what data can be made available, or the specificity of it?
b. Has the data that has been available so far proven helpful or been used in any practice?
c. Is there a new updated scheduled for release?

Response to Question 10:
The IBM product did not meet operational requirements and SCE discontinued its use. SCE has since engaged other vendors, such as PSSC Labs and Atmospheric Data Solutions, to provide enhanced replacement functionality that will include a high-resolution weather forecast analytics system including two high-performance computing clusters (HPCC) using the latest specialized hardware designed to efficiently run the Weather Research and Forecasting model (WRF) across SCE's service area. The forecast analytics will include wildfire potential, load and outage forecasts, in addition to standard weather variables. SCE is in the final stages of the contracting process and is close to issuing Purchase Orders so the vendors can begin performing work. Initial model output is scheduled to be available by third quarter 2019.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 5

To: Cal PA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 1/15/2019

Response Date: 2/28/2019

Question 03: On pages 65-66 of its testimony, SCE discusses the elimination of tree attachments.

a. How many tree attachments does SCE have in its entire system?
b. Of these, how many are located in HFRA Tiers 2 or 3?

If a precise number are not available for either of these subparts, please provide SCE's best estimate and the basis for this estimate.

Response to Question 03:

a. Based on inventory mapping, there are a total of 4,445 tree attachments in SCE's electrical system. Approximately 95% of these attachments are located in the San Joaquin and Rural regions.

b. Assessing the San Joaquin and Rural regions (or approximately 95% of the total tree attachments), there are 1,797 in Tier 2 HFRA and 1,725 in Tier 3 HFRA.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 1 1

To: CalPA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 3/26/2019

Response Date: 4/9/2019

Question 01: Does SCE have or is it aware of any studies, analyses, or other information regarding the safety of tree attachments? If so, please provide.

Response to Question 01:
SCE is not aware of any studies, analysis, or other information regarding the safety of tree attachments. However, our experience suggests that it is prudent to remove tree attachments. Some of the identified safety and reliability drivers supporting this position include:

- Increasing tree mortality due to drought and bark beetle infestation
- Increase in damages/failures due to fallen trees/branches, which can be attributed to an increase in tree mortality
- Challenging work terrain, which is inaccessible by vehicle and may require tree climbing, helicopters, and/or hand digging

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 1 1

To: CalPA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 3/26/2019

Response Date: 4/9/2019

Question 02: Have tree attachments on SCE's system been linked to any safety or reliability incidents in the past 5 years? If so, please describe.

Response to Question 02:
SCE does not explicitly track tree attachment failures. However, SCE's experience in regions with a high concentration of tree attachments indicates faults/damages are due to failure of, or branches falling from, the tree to which utility equipment is attached. Accordingly, SCE believes it is prudent to remove tree attachments. As noted in SCE's Response to Question No. 1, some of the identified safety and reliability drivers supporting this position include:

- Increasing tree mortality due to drought and bark beetle infestation
- Increase in damages/failures due to fallen trees/branches, which can be attributed to an increase in tree mortality
- Challenging work terrain, which is inaccessible by vehicle and may require tree climbing, helicopters, and/or hand digging

DATA REQUEST SET C A L P A - S C E - 0 1 1

To: CalPA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 3/26/2019

Response Date: 4/9/2019

Question 04:
Has SCE installed any new tree attachments in the last 5 years? If so, please state how many (per year). If not, please state when the last new tree attachment was installed.

Response to Question 04:
Tree attachments are no longer utilized for new construction and SCE is not aware of any new construction for at least the past 5 years. However, under severe weather conditions and/or during an emergency condition, SCE may perform a repair to a tree attachment in order to restore service quickly.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 1 1

To: CalPA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 3/26/2019

Response Date: 4/9/2019

Question 03: Please provide the rate of tree attachment removal on SCE's system for the past 5 years.

Response to Question 03:
SCE does not track failures of tree attachments, and additionally does not install any new tree attachments, the rate of removal was not a tracked metric prior to 2017.

SCE has identified a total of 4,445 tree attachments in the service territory. Since 2017, the amount of work performed related to tree attachments was as follows.

- Total Tree Connects Addressed: 319
- Total Poles Installed: 238
- Overall Structures/Attachments Eliminated: 81
- Total work orders: 63

The tree attachment removals performed were typically related to reactive maintenance and repair activities such as response to drought conditions and tree mortality.

DATA REQUEST SET C A L P A - S C E - 0 1 1

To: CalPA
Prepared by: Hunly Chy
Job Title: Manager
Received Date: 3/26/2019

Response Date: 4/9/2019

Question 05: Does SCE consider the removal of tree attachment to be an industry best practice? Please describe.

Response to Question 05:
SCE has not performed industry benchmarking with regard to tree attachments. However, SCE believes there is greater reliability and safety benefits by transitioning all tree attachments to poles. As stated in SCE's Response to Question 1, the key drivers for removing tree attachments are:

- Increasing tree mortality due to drought and bark beetle infestation
- Increase in damages/failures due to fallen trees, which can be attributed to an increase in tree mortality
- Challenging work terrain which is inaccessible by vehicle and may require tree climbing, helicopters, and or hand digging

Southern California Edison
A.18-09-002 Grid Safety & Resiliency Program

DATA REQUEST SET C a l P a - S C E - 0 0 4

To: CalPa
Prepared by: Ryanne N Spady
Title: Senior Advisor Dated: 12/28/2018

Question 06: Please provide a table of the voltages of the lines to be reconductored as part of SCE's proposed covered conductor program, as well as the total length of lines of that voltage.

If such information is not completely available at this time (for example due to incomplete engineering or re-engineering), please provide all known information, the total length/scope of unknown information, and the date when such information will be available.

Response to Question 06:
See the Table below for forecasted GSRP covered conductor scope by voltage. This forecast is based on a combination of scope that has been identified though detailed engineering and a desktop exercise. Detailed engineering for 2018 and 2019 scope has already been completed. Detailed engineering for 2020 scope is expected to be completed by Q3 2019 and could lead to some refinements in total miles estimated.

Table: Estimated GS&RP Covered Conductor Scope (2018-2020 Distribution Overhead Primary)

Circuit Name	Voltage	GS&RP Covered Conductor Scope	Total Circuit Length (HFRA)
THACHER	16	83.6	83.6
METTLER	12	46.6	130.1
CUDDEBACK	12	89.4	89.4
JORDAN	12	164.0	164.0
HUGHES LAKE	12	89.6	89.6
CHAWA	12	49.9[1]	99.0
GALAHAD	16	37.4	57.4
TITAN	12	0.0	103.1
TENNECO	12	31.5[2]	100.4

---

[1] Detailed engineering has been completed for Chawa and identified 54 circuit miles of reconductor for this circuit. SCE completed approximately four miles of this circuit prior to the GSRP filing.
[2] Additional scope for Tenneco is planned for 2021

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET C A L P A - S C E - 0 0 8

To: CalPA
Prepared by: Desiree Wong
Job Title: Senior Advisor
Received Date: 3/16/2019

Response Date: 3/25/2019

Question 01: SCE's response dated 2/26/2019 to Question 1 of CALPA – SCE – 005 states that SCE has not yet begun recording costs to the GSRP Memorandum Account (GSRPMA).

a) Is SCE tracking the costs to be recorded in the GSRPMA?
b) If yes, what date did SCE begin tracking the costs to be recorded in the GSRPMA?
c) What is the distinction between recording and tracking costs in the GSRPMA?
d) Does SCE believe that it may request recovery of costs that are not recorded in the GSRPMA? If so, why?
e) The Edison International and Southern California Edison Company Form 10-K for the fiscal year ended December 31, 2018 states (p.9) that GSRP capital expenditures for 2018 were $54 million. Does SCE expect to request recovery of these and any other 2018 expenditures? If so, under what mechanism?

Response to Question 01:
1a. SCE submitted Advice 3950-E on February 8, 2019 to establish the GSRP Memorandum Account (GSRPMA). Because that Advice Letter is still pending approval, the GSRPMA has not yet been formally established, and SCE has not yet recorded any costs to the GSRPMA. As such, the process for tracking GSRP costs that will ultimately be recorded to GSRPMA has been manual (*i.e.*, manual aggregation of GSRP-related work orders) and only performed on an ad-hoc basis.

1b. See 1a.

1c. Once the GSRPMA is established, there is no distinction between the terms "recording" and "tracking" costs.

1d. As described on page 145 of SCE's Opening Testimony, SCE proposes that the GSRP Balancing Account be established once the Commission issues a final Decision in this proceeding to recover the GSRP costs. Only the costs recorded in the GSRPMA will be transferred to the GSRP Balancing Account for recovery from customers.

1e. Any GSRP-related costs incurred since September 10, 2018 will be recorded to the GSRPMA once it has been established. Those costs will be transferred to the GSRP Balancing Account upon receiving a final Decision in this proceeding for recovery from customers.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Wildfire

Chapter 10

Rosemead CA
November 15, 2018

Contents

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I. Executive Summary

A. Overview

Southern California Edison (SCE) provides electric service to over five million customers in a 50,000 square-mile service area. Approximately 35% of this service territory is in High Fire Risk Areas (HFRA).[1] This chapter will address the risk of wildfire ignitions associated with SCE workers and assets. To perform this risk analysis, SCE developed a risk bowtie that includes risk drivers, triggering events, outcomes, and consequences. SCE also quantified the potential safety, reliability, and financial impacts resulting from this risk.

Wildfire mitigation measures have long been integral to our operational practices. SCE has several current controls in place that include, but are not limited to: our Vegetation Management Program, our Overhead Conductor Program (OCP), operational procedures (such as recloser blocking), and the recently introduced ester fluid-insulated Overhead Transformers. These programs help reduce the frequency or the impacts of wildfires.

SCE has evaluated existing controls and potential new mitigations to address this risk, and we have developed a Proposed Plan and two Alternative Plans. The Proposed Plan includes a portfolio of work that balances risk mitigation, execution feasibility, and cost-effectiveness. The plan leverages our existing controls, and includes new and expanded mitigations designed to reduce the risk of wildfires. Finally, as discussed throughout this chapter, this Proposed Plan aligns with SCE's Grid Safety and Resiliency Program (GS&RP) Application, A.18-09-002.

B. Scope

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

Table I-1 – Scope of Chapter

In Scope	Ignition associated with SCE Overhead Distribution Equipment
Out of Scope	Ignition associated with SCE Transmission/Substation Equipment,[2] Ignitions not associated with SCE.

[1] The term "High Fire Risk Areas" refers to the locations in SCE's service territory that have been given a Tier 2 or Tier 3 designation in the most recent CPUC High Fire Threat District maps (CPUC Fire Maps). See D.17-12-024. The term also encompasses any additional locations that SCE had previously identified in its service area as high fire risk areas prior to the release of the most recent CPUC Fire Maps.
[2] In this chapter, SCE focuses on risks associated with SCE's distribution equipment because approximately 90 percent of all of the fires associated with electrical equipment in SCE's service area are related to distribution level voltages (33kV and below). However, some of the mitigation measures

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C. Summary Results

Table I-2 summarizes the controls and mitigations included in this chapter, as well as the results of SCE's risk evaluation using SCE's Multi Attribute Risk Scoring (MARS) framework. As discussed in more detail below, the table shows that the MRR and RSE of the Proposed Plan is comparable to Alternative Plan #1 when examined in terms of mean results. The Proposed Plan has a higher MRR and a lower RSE than Alternative Plan #1 when examined in terms of tail average results.

This table also shows that the Proposed Plan has a lower MRR and a higher RSE than Alternative Plan #2 in terms of both mean and tail average results.

SCE discusses in detail in Sections V, VI, and VII the reasons why we recommend the Proposed Plan at this time, rather than Alternative Plan #1 or Alternative Plan #2.

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discussed in this Chapter will reduce fire risk for transmission facilities as well. These include, for example, situational awareness mitigation measures including HD cameras, weather stations, and advanced weather models (M7). SCE qualitatively discusses some direct safety risks associated with transmission and substation facilities in Appendix B of the RAMP Report. Going forward, SCE intends to perform more detailed quantitative analysis of transmission-related wildfire risks in future analyses.

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Table I-2 – Summary Results (Annual Average over 2018-2023)[3]

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Overhead Conductor Program (Bare + Covered)	x		x
C1a	Overhead Conductor Program - (Bare Only)		x	
C2	FR3 Overhead Distribution Transformer	x	x	x
M1	Wildfire Covered Conductor Program	x		
M1a	Wildfire Covered Conductor Program (including covered and bare sections)		x	
M1b	Underground Conversion			x
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	x	x	x
M3	PSPS Protocol and Support Functions	x	x	x
M4	Infrared Inspection Program	x	x	x
M5	Expanded Vegetation Management	x	x	x
M6	Microgrids			x
M7	Enhanced Situational Awareness	x	x	x
M8	Fusing Mitigation	x	x	x
M9	Fire Resistant Poles (M1 Scope)	x		
M9a	Fire Resistant Poles (M1a Scope)		x	
M9b	Fire Resistant Poles (M1b Scope)			x
Mean (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	6.9	6.9	6.9
	Risk Reduction (MRR)	1.3	1.2	1.3
	Remaining Risk	5.6	5.7	5.6
	Risk Spend Efficiency (RSE)	0.0037	0.0039	0.0013
Tail Average (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	24.0	24.0	24.0
	Risk Reduction (MRR)	4.3	4.1	4.3
	Remaining Risk	19.7	19.9	19.7
	Risk Spend Efficiency (RSE)	0.0126	0.0134	0.0042

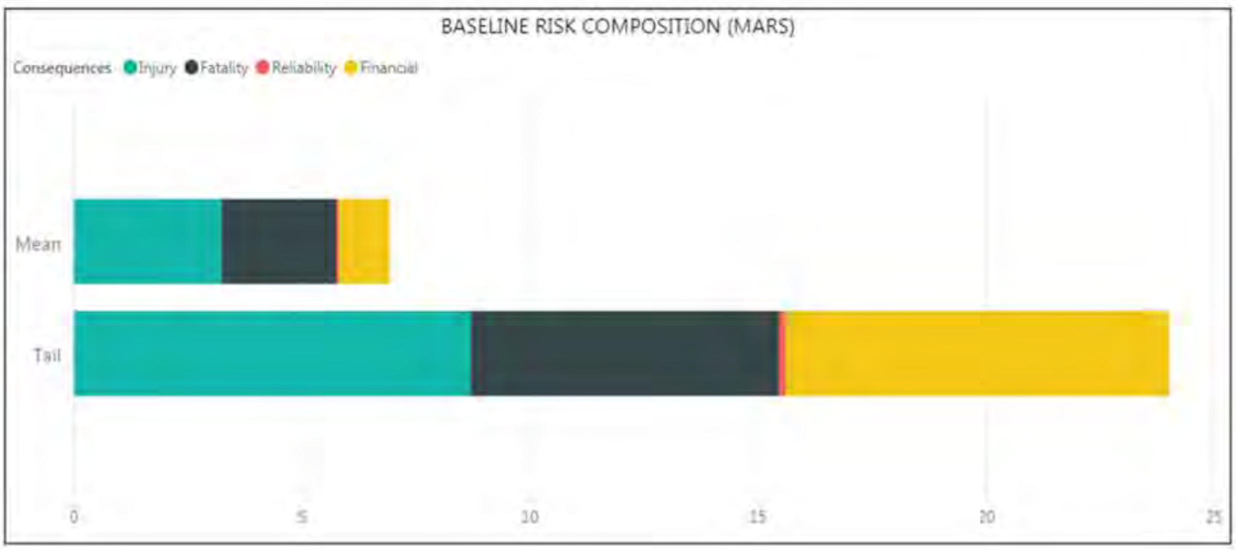
CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

[3] The OCP controls (C1 and C1a) represent a small share of the conductor-related controls in the HFRA when considering the Wildfire Covered Conductor Program mitigations (M1, M1a and, M1b). In all three of the portfolios, the control is 9% of the total conductor-related scope.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 illustrates the baseline risk associated with Wildfire. The mean result is the average result across all simulations. The tail result is the average of the most extreme ten percent of simulations. In other words, the tail indicates lower-probability, higher-impact events. The color coding represents the contribution from each of the risk attributes analyzed in this RAMP report. This figure shows that safety (serious injuries and fatalities) constitutes the largest impact on both a mean and a tail-average basis. However, financial impacts become considerably more significant when evaluating this risk on a tail-average basis.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

California is experiencing a sharp increase in the size of wildfires and the damage they cause. Unfortunately, 2017 was an historic year for wildfires in our state. Within SCE's service area, the Thomas Fire,[4] which occurred in December 2017, became the eighth most destructive wildfire in California since the early 1900s. Outside of SCE's service area, the Tubbs Fire[5] in October 2017 was notable for the number of fatalities and the time of year. As we moved into 2018, the Mendocino Complex fire,[6] which began in July of 2018, became the largest fire in California's history.

These three fires are examples of the increasing size and devastation of wildfires in California. In addition, the wildfire season has expanded to be a "year-round" fire season in California, constituting a "new normal."[7, 8]

Several factors contribute to the risk of wildfire and its consequences, including but not limited to an increase in construction in California's wilderness-urban interface areas, and the effects of climate change. The construction increase, primarily residential, expands the potential damage to property and loss of life due to wildfires. Nearly 35% of wildfires begin in this high-risk wildland-urban interface[9] where the risk of property damage and fatalities is greatest.

California's weather conditions are changing. Drought conditions have become more severe, and their durations are getting longer;[10] non-drought conditions are becoming shorter.

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[4] The Thomas Fire burned 281,893 acres between December 4, 2017 and January 12, 2018 destroying 1,063 structures, damaging 280 structures, injuring two firefighters, and causing two fatalities.

[5] The Tubbs Fire burned 36,807 acres between October 8, 2017 and October 31, 2017 destroying 5,643 structures, injuring one individual and causing 22 fatalities.

[6] As of September 5, 2018, the Mendocino Complex fire burned 459,123 acres, destroyed 280 structures, and caused 3 injuries and 1 fatality, in Northern California.

[7] Quote from Governor Edmund G. Brown's news conference on December 9, 2017 at the Ventura County Fairgrounds, after his tour of the fire areas.

[8] Marissa Clifford, *In California, It's Always Fire Season Now*, LA CURBED (June, 2018), *available at* https://la.curbed.com/2018/6/5/17428734/wildfires-calfornia-risk-prediction .

[9] Article gives further insight into wildfires started in the Wildland-urban interface. Schoennagel, Tania; Balch, Jennifer K.; Brenkert-Smith, Hannah; Dennison, Philip E.; Harvey, Brian J.; Krawchuk, Meg A.; Mietkiewicz, Nathan; Morgan, Penelope; Moritz, Max A. (2017-05-02). "Adapt to more wildfire in western North American forests as climate changes." *Proceedings of the National Academy of Sciences*. **114** (18): 4582–4590. http://www.pnas.org/content/114/18/4582.

[10] Scott Stephens et al., Drought, Tree Mortality, and Wildfire in Forests Adapted to Frequent Fire, 68

For example, severe drought conditions led to Governor Brown proclaiming a State of Emergency on January 17, 2014; Governor Brown "directed state officials to take all necessary actions to prepare for the drought conditions."[11] On April 25, 2015, Governor Brown issued Executive Order B-29-15 that proclaimed a Continued State of Emergency and, among other things, ordered significant water conservation measures. Weather conditions, such as those that propagate drought conditions, are contributing to the increase in the number of days California is under extreme fire danger and to our state facing a year-round fire season with constant wildfire risk.[12]

The Commission has addressed wildfire risk, and the risks from wildfires associated with utility infrastructure, in Rulemaking R.15-05-006. The Commission has approved revised fire threat maps and increased inspection and vegetation management requirements in these areas. Beyond these efforts, SCE is proposing additional measures to harden and upgrade our system to further prevent utility-associated wildfires and to further mitigate system impacts when a fire occurs. These measures are included in SCE's GS&RP Application.

The risk analysis presented in this chapter aligns with the GS&RP filing.[13] Both filings utilize similar underlying data and assumptions regarding risk drivers and mitigation effectiveness. This RAMP chapter quantifies the risk reduction benefits of mitigations in the GS&RP portfolio. However, there are necessarily certain inherent differences in analysis methodologies. Generally speaking, these differences occur because:

- Costs in RAMP are represented in nominal dollars, while the costs in the GS&RP filing are represented in 2018 constant dollars. This will create a variance in total forecast. However, the underlying scope identified for the various mitigations for specific time periods will be the same.
- RAMP requires considering the forecast period of 2018-2023. The GS&RP application is intended to justify the program from the filing date of 9/10/2018 through year-

BIOSCIENCE 77, 78 (Feb. 2018), available at https://www.fs.fed.us/psw/publications/fettig/psw_2018_fettig002_stephens.pdf

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

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

[13] For a detailed discussion on the alignment between RAMP and the GS&RP riling, please refer to WP Ch. 10, pp. 10.47-10.51 *(RAMP to GSRP Comparison Workpaper).*

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

- The RAMP analysis only counts benefits that occur during 2018-2023, while GS&RP considers benefits for all future years. In section V below, we discuss in greater detail the difference in benefits when the long-term benefits are included, compared to restricting the benefits period to years 2018-2023.
- The proposed RAMP portfolio excludes Wildfire Mitigation Program Study Costs. These costs are intended to allow SCE to explore new technologies to reduce future risk.
- The wildfire risk model SCE developed for RAMP evaluates wildfire events based on size ("more than" or "less than or equal to" 5,000 acres) and whether the wildfire event occurs on days when a Red Flag Warning[14] was either "in effect" or "not in effect." The GS&RP conductor-based comparative analysis does not distinguish between these differences.

Figure II-1 below summarizes the risk bowtie that SCE used to model wildfire risk in this chapter.

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[14] Red Flag Warning is a term used by fire-weather forecasters to call attention to limited weather conditions of particular importance that may result in extreme burning conditions. It is issued when it is an ongoing event, or when the fire weather forecaster has a high degree of confidence that Red Flag criteria will occur within 24 hours of issuance. Red Flag criteria occurs whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, and the National Fire Danger Rating System (NFRDS) is high to extreme and the following forecast weather parameters are forecast to be met: 1) a sustained wind average 15 mph or greater; 2) relative humidity less than or equal to 25 percent; and 3) a temperature of greater than 75 degrees F. In some states, dry lightning and unstable air are criteria. A Fire Weather Watch, for conditions that may exist within 12-72 hours, may be issued prior to the Red Flag Warning.

Figure II-1 – Risk Bowtie

B. Driver Analysis

To identify the drivers that caused the triggering event (ignition associated with SCE in High Fire Risk Area), SCE analyzed the fires that occurred in SCE's service area between 2015 and 2017 that were reportable to the CPUC.[15] This analysis yielded four major categories of drivers:

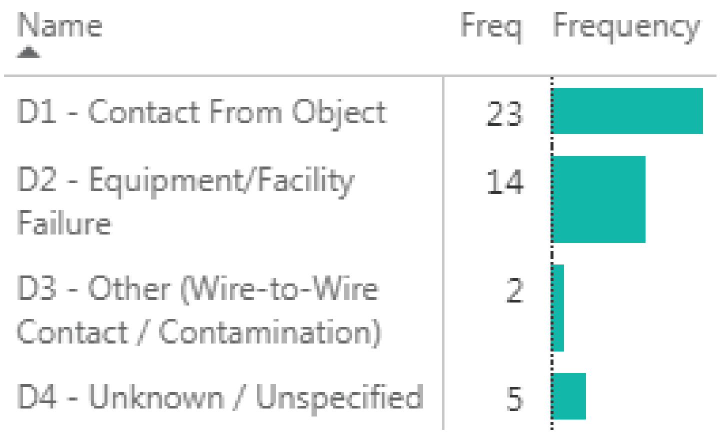
1. D1 - Contact From Object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/Facility Failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-Wire Contact/Contamination; and,
4. D4 – Unknown/Unspecified.

To develop the number of events for each driver, SCE analyzed the ignition events identified above to exclude events that did not occur in HFRA. For purposes of risk modeling, SCE rounded the three-year averages for each driver to the nearest whole number. This rounding resulted in some low-frequency drivers having a three-year average of zero, and does not impact the risk analysis results. SCE identified four drivers, as shown in Figure II-2 below. As detailed below, we

[15] Per D.14-02-015, reportable fire events are any events where utility facilities are associated with the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities; (b) the resulting fire traveled greater than one linear meter from the ignition point; and (c) the utility has knowledge that the fire occurred.

were able to subdivide two of these drivers (D1 and D2). This greater granularity helped us better understand the causes of this risk.

Figure II-2 – 2018 Projected Driver Frequency[16]



SCE performed analyses that correlated fire events to faults on SCE's distribution system. These faults, which have historically occurred from all drivers and sub-drivers shown in Figure II-1, can result in arcing during the fault event. When this arcing contains sufficient energy—given local conditions such as temperature, humidity, and nearby fuel source—ignition can result and lead to a wildfire.[17] Figure II-3 illustrates how the two most prevalent categories of faults can lead to wildfires.

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

[17] The concept of fault energy can be described as the electric system's natural reaction to fault conditions. Dominant factors for fault energy are the duration and the magnitude of electrical current during a fault. In essence, reducing fault energy helps reduce the probability of ignition.

Figure II-3 – Illustrative Event Diagram for Wildfire Ignitions Originating from Faults on Overhead Circuits

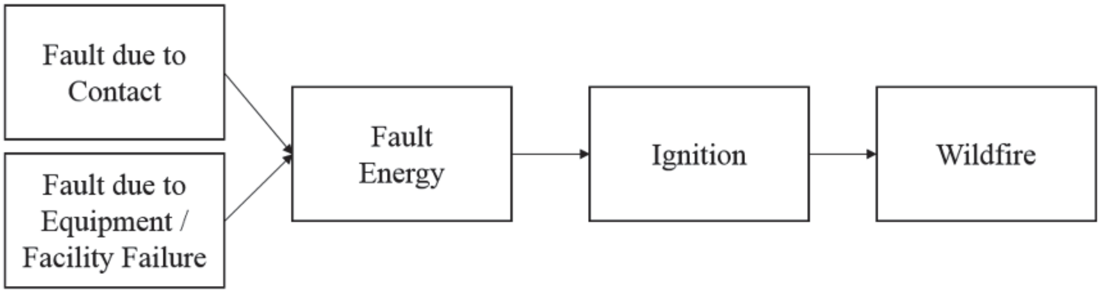


Table II-1 breaks down the different driver categories used within our risk modeling efforts. Table II-2 and Table II-3 break down the sub-drivers of Contact from Object and Equipment/Facility Failure, respectively.

Table II-1 – Driver by General Category

	Annual Count				
Suspected Initiating Event	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1 - Contact From Object	23	21	26	23	52%
D2 - Equipment / Facility Failure	10	21	9	14	32%
D3 - Other (Wire to Wire Contact / Contamination)	4	0	2	2	5%
D4 - Unknown / Unspecified	7	2	7	5	12%
Total	**44**	**44**	**44**	**44**	**100%**

Table II-2 – D1 (Contact from Object) Sub-Driver Statistics

	Annual Count				
D1 - Contact From Object	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1a - Animal	7	5	3	5	11%
D1b - Balloons	2	3	9	5	11%
D1c - Other	2	5	3	3	7%
D1d - Vegetation	8	6	8	7	16%
D1e - Vehicle	4	2	3	3	7%
Total	**23**	**21**	**26**	**23**	**52%**

Table II-3 – D2 (Equipment/Facility Failure) Sub-Driver Statistics

	Annual Count				
D2 - Equipment / Facility Failure	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D2a - Capacitor Bank	0	1	1	1	2%
D2b - Conductor	2	8	2	4	9%
D2c - Crossarm	0	0	1	0	0%
D2d - Fuse	0	1	0	0	0%
D2e - Insulator	1	2	2	2	5%
D2f - Splice/Clamp/Connector	3	4	1	3	7%
D2g - Transformer	1	1	1	1	2%
D2h - Other	3	4	1	3	7%
Total	**10**	**21**	**9**	**14**	**32%**

As we described above in section II-B, SCE ascertained the drivers (i.e., the causes of the fire events) by analyzing the fires that occurred between 2015 and 2017 in SCE's service territory that were reportable to the Commission. The drivers and sub-drivers presented in these tables are described below.

1. D1 – Contact from Object

a. D1a – Contact from Object – Animal

Many animals come in contact with SCE's distribution facilities on a daily basis. When an animal or bird is sitting or walking on an overhead conductor, its feet are at the same voltage potential[18] and the animal or bird will not be electrocuted. However, electrocution occurs when one of the animal's feet comes into contact with an object at a different potential (such as another conductor or a grounded object like a tree) while the other foot (or feet) remains on the conductor. Electrocution results in severe injury, or death, to the animal and damage to the conductor and other electrical equipment impacted by the fault. Additionally, the remains of the animal itself can ignite and become a fire risk.

b. D1b – Contact from Object - Balloons

Foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[19] has recognized this concern, and requires that all helium-filled foil balloons be weighted, to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines it can create a short circuit. This can cause a large power arc, resulting in circuit damage, overheating, fire, or an explosion.

[18] Voltage potential is a measure of the propensity for electricity to travel from one point to another.
[19] California SB 1990, "Balloon Law."

c. D1c – Contact from Object – Other

Contact from other unspecified objects, or foreign material, include items such as tennis shoes, chains, gunshots, ice, crop dusting and other items. Each object has the potential to cause different types of failures, ranging from a fault to equipment failure, or ignition of the object itself.

d. D1d – Contact from Object – Vegetation

Even with SCE's existing vegetation management programs (see Compliance Control (CM1) – Vegetation Management in Section III), vegetation can still make contact with overhead conductor and cause an ignition and/or a wire down event. Branches or palm fronds can break or come loose from the main tree and fall, or can be blown by wind into overhead conductor. Besides causing faults, these branches and palm fronds can ignite and become additional fire risks.

Branches or palm fronds that blow into overhead conductor can come from trees in excess of 200 feet away depending on the wind and terrain. This distance is well beyond required clearances. Additionally, vegetation growth rates can vary, and trees or other vegetation may grow faster than anticipated between scheduled inspections. Vegetation can grow into lines and make contact, despite SCE's efforts to inspect and maintain clearances throughout our 50,000 square-mile area.

e. D1e – Contact from Object – Vehicle

Vehicles can come into contact with SCE poles and other aboveground equipment, resulting in damage to the pole and/or equipment.[20] Vehicle impact causes SCE's equipment to fail in many ways: conductor or other equipment falling to the ground; conductor slapping together causing a fault; or the pole falling to the ground and taking the conductor with it. Sometimes, the failure can result in a wildfire.

2. D2 – Equipment / Facility Failure

a. D2a – Equipment / Facility Failure – Capacitor Bank

SCE uses capacitor banks to compensate for reactive power losses and to regulate voltages on the distribution system. Approximately 85% of all distribution capacitor banks on the SCE system are installed on overhead circuits. Failing capacitor banks may create

[20] Although not covered in this risk analysis, SCE is sensitive to the fact that there can also be injury to the driver and damage to the vehicle.

arcing from the associated equipment, and the released electrical energy can be enough to ignite fires, either at ground level or at pole-top level.

b. D2b – Equipment/Facility Failure – Conductor

When an energized conductor fails and hits the ground, wildfire ignition can occur. In general, there are two ways overhead conductor can experience failure.

The first is when the system's short circuit duty (SCD) exceeds a conductor's rating. Generally, SCD indicates the relative strength of an electrical system, typically measured by the current (in amps) that the system can supply when fault conditions occur. If, at any given point in the system, fault current exceeds the conductor's ability to withstand it, then fault conditions can damage the conductor and lead to conductor failure. Vintage small conductor is especially vulnerable to damage during fault conditions, because it typically possesses a lower conductor rating, or current carrying capacity, compared to larger conductor.

The second is conductor fatigue. Conductor fatigue refers to the decrease in overhead conductor's ability to withstand forces experienced during operational conditions. For overhead wire, the likelihood of fatigue-related failures tends to increase over time, as the conductor is exposed to longer periods of operational stress. For example, overhead conductors have both a normal long-term thermal rating and a higher short-term emergency thermal rating. Emergency thermal ratings are used to accommodate higher levels of load. These ratings are typically relied on during abnormal operating conditions, such as when transferring customers between adjacent circuits in order to restore service as rapidly as possible during circuit outage conditions.

Beyond the operating conditions described above, the conductors could also be exposed to very high-magnitude short circuit current from time to time when there is a fault condition further downstream in the circuit. Even though these short circuit currents are typically very brief in duration, the extremely high current level can result in a rapid increase in localized temperature of the conductor. This can start to change the molecular structure of the conductor material; the result is a significant and permanent reduction in the mechanical strength of the conductor. When coupled with other induced mechanical loading such as wind, vibration, and other environmental factors, this will contribute to the conductor experiencing fatigue-related failures at some point in its lifetime.

c. D2c – Equipment/Facility Failure – Crossarm

Crossarms are mounted on distribution poles and used to support overhead conductor or other pieces of overhead distribution equipment. As crossarm pieces weaken or deteriorate over time, either the crossarm can break or the bracket that attaches the crossarm to the pole can fail. In either case, conductor can come into contact with other conductors, the pole, other pieces of electrical equipment, or the ground. This may lead to the causal fault chain shown in Figure II-3 above, with the end result being a wildfire.

d. D2d – Equipment/Facility Failure – Fuse

Fuses are protective devices designed to clear system faults by interrupting fault current and de-energizing circuits downstream of the fuse. Fuses are essentially thermal devices designed to melt at a specified current in a specified time. Fault clearing times, or the time it takes a fuse to activate, generally depend on both current and time. Faster fault clearing typically occurs for higher levels of fault current, while slower fault clearing occurs for lower levels of fault current.

When the fuse element melts, it must be able to do so without causing catastrophic failure of the fuse itself. Such fuse failures can cause prolonged fault conditions, equipment damage, or fire ignition.

e. D2e – Equipment/Facility Failure – Insulator

Insulators provide mechanical support to energized conductors and maintain electrical isolation between energized conductors and grounded structures such as poles.

Insulators can fail in various ways. For example, insulators, especially older glass or porcelain insulators, can be broken by contact from a wide range of foreign objects, from hail storms to gunshots. The mounting part of insulators that connects the insulator to the crossarm can deteriorate over time and break or come loose. The tie that connects the energized conductor to the insulator can also come loose; this can damage the conductor over time or detach completely from the conductor. In any of these cases, the insulator failure leads to loss of mechanical support for the conductor. This causes the conductor to come into prolonged contact with the pole, with other equipment, or with the ground. Any such contact can eventually lead to an ignition.

f. D2f – Equipment/Facility Failure – Splice/Clamp/Connector

Splices, clamps, and connectors are three different devices used to connect overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector or clamps. Spans of conductors are connected to other spans of conductor with a splice. These devices can degrade due to exposure to the elements, and can be damaged as the result of faults on the circuit. Faults on a circuit and the resulting fault current can cause these devices to overheat and melt, causing the overhead conductor to fall to the ground. Failures of splices can result in a conductor coming down and faulting due to contact with other equipment, objects, or the ground.

g. D2g – Equipment/Facility Failure – Transformer

Distribution transformers can fail for several reasons. One common reason for transformer failures is heavy transformer loading over extended periods of time. Such conditions cause transformers to heat up. This prolonged loading at or near the transformer's rated loading condition can also shorten the useful life of the insulation material. This increases the probability of failure. This problem is exacerbated during extended heat wave conditions, because the equipment does not have the necessary time to cool.

Historically, SCE has experienced a high number of transformer failures during heat storms. The exterior shell of the transformer can deteriorate over time and leak oil, which can also lead to failure. Moreover, because transformers contain oil, when transformers overheat they can fail violently and cause a fire.

h. D2h – Equipment/Facility Failure - Unspecified

This driver category captures wire-down events where field personnel have attributed the event to equipment failure, but the specific equipment detail is not provided.

3. D3 – Wire-to-Wire Contact / Contamination

Wire-to-wire contact can occur during high winds or during conditions where third parties make contact with poles or conductors. The factors that can contribute to wire-to-wire contact include the phase spacing, pole geometry, and conductor tension on each phase of the circuit. When wire-to-wire contact occurs, fault conditions can damage the conductor and cause conductor failure.

Contamination is a phenomenon typically associated with the insulators that support the conductor in a distribution circuit. Contamination-related flashovers typically begin when some type of airborne contaminant combines with moisture from fog, rain, or dew and collects on the surface of insulators. These contaminants can begin to conduct current across the insulators. Unless corrective action is taken, this current can cause the insulator to not perform as intended, resulting in a "flashover." Such flashovers can cause conductor or insulator damage and can lead to a wire-down.

4. D4 – Unknown / Unspecified

Unknown includes incidents where the cause was not identifiable. An example could be a fault on the system where an object made contact with a line but was subsequently blown or dispersed away from the line before SCE personnel arrived at the location.

C. Triggering Event

SCE utilized one triggering event related to wildfire risk. As shown in Figure II-1, this triggering event is "Ignition Associated with SCE in High Fire Risk Areas." This single triggering event can result from the many drivers discussed above and can lead to the outcomes and consequences described below.

D. Outcomes & Consequences

SCE identified four outcomes for the wildfire triggering event as shown in Figure II-1. These four outcomes are based on Red Flag Warnings and the size of the fire. SCE used the Red Flag Warning days because of the higher fire risk during those events and SCE's operating procedures when a Red Flag Warning is in effect within SCE's service area.

SCE also distinguished between fires greater than 5,000 acres and less than 5,000 acres. SCE used the 5,000 acre cutoff to distinguish between large fires with significant safety, financial, and reliability consequences, and smaller fires with lesser consequences. This size cutoff aligns with the largest size classifications for ignitions reported to the Commission per D.14-02-015. Additionally, SCE observed that all fires recorded by CalFire with a cause of "Electrical Power" from 2007-2017 showed recorded fatalities only for large fires greater than 5,000 acres.[21]

To show the likelihood of each outcome occurring, SCE analyzed the fires that occurred in SCE's HFRA service area between 2015 and 2017 that were reportable to the CPUC. Fire size is tracked as part of this CPUC reporting.[22] SCE analyzed meteorological data to identify which fires occurred during Red Flag Warnings. The results are shown for each individual outcome in Figure II-4 below.

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[21] The California Department of Forestry and Fire Protection (CalFire) publishes an annual Wildfire Activity Statistics report, commonly known as the "Redbook." http://www.fire.ca.gov/fire_protection/fire_protection_fire_info_redbooks

[22] For Outcome O3 – "Wildfire Red Flag Warning Not in Effect Greater than 5,000 Acres," SCE's data reported zero fires with this outcome. For analysis purposes, SCE included a 0.19% probability, based on the ratio of CalFire incidents occurring on Red Flag Days compared to non-Red Flag Days for fires greater than 5,000 acres. Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

Figure II-4 – 2018 Outcome Likelihood[23]

Name	%	Percent
O1 - Wildfire Red Flag Warning in Effect Greater than 5,000 Acres	0.8 %	
O2 - Wildfire Red Flag Warning in Effect Less Than 5,000 Acres	31.0 %	
O3 - Wildfire Red Flag Warning Not in Effect Greater Than 5,000 Acres	0.2 %	
O4 - Wildfire Red Flag Warning Not in Effect Less Than 5,000	68.1 %	

For each outcome, SCE identified applicable consequences, and modeled these consequences using statistical distributions. For many consequences modeled in this chapter, SCE developed a distribution based on CalFire's published fire statistics, with cause classifications assigned by CalFire as "Electrical Power," which is defined as "Fire ignited by electrical power distribution or transmission."[24]

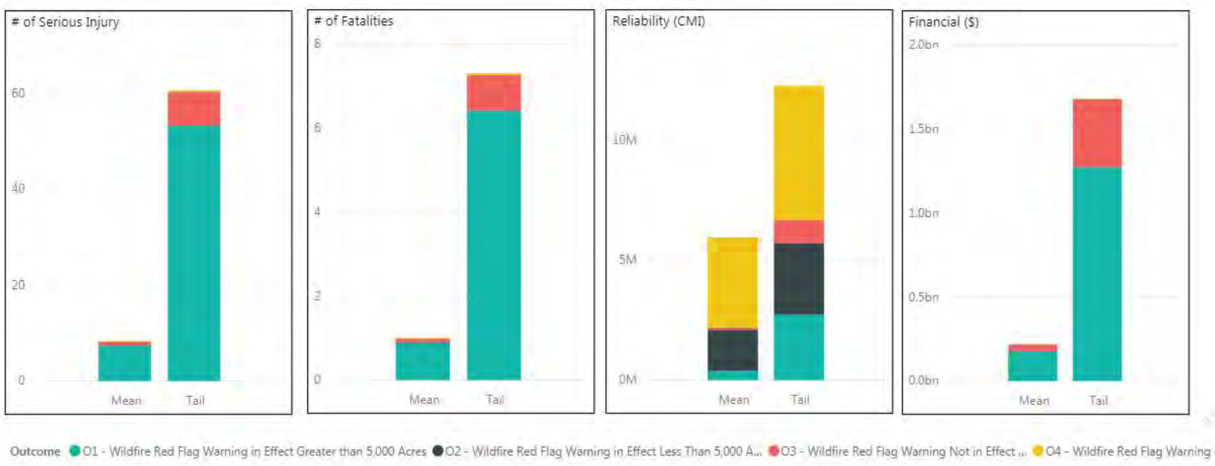
Please see Chapter 2 (Risk Model Overview) for additional detail regarding the outcome and consequence distribution modeling process. The sections that follow detail the data used to inform the development of these distributions.[25]

The wildfire events included within CalFire data encompass events in SCE's service area, as well as a number of events that occurred outside our service area but within California. The CalFire data population of fires associated with Electrical Power in SCE's service is relatively small, especially for fires greater than 5,000 acres. By including events from areas outside of SCE's service area, SCE could provide a more robust wildfire risk analysis. SCE's consequence modeling utilizes this CalFire data for fatalities, structures destroyed, and acres burned.

Figure II-5 illustrates the composition of the modeled baseline risk in terms of each consequence dimension, shown in natural units, on both a mean and tail-average basis. The sections that follow examine the inputs used to derive these results. Figure II-5 shows that O1 (Red Flag Day, >5,000 Acres), accounts for most of the serious injury, fatality, and financial impacts of this risk. Conversely, O4 (Non-Red Flag Day, <5,000 Acres) accounts for the majority of reliability impacts of this risk.

[23] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[24] http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF
[25] Note that SCE includes wildfire consequences from across California to develop these distributions, due to the relatively low number of large fires in SCE service area.

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



1. O1 – Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 0.8% of wildfire events we evaluated result in this outcome. Wildfires that occur during Red Flag Warnings have the potential to be more aggressive and faster-moving fires. This is due to environmental conditions such as low relative humidity, strong winds, dry fuels, the possibility of dry lightning strikes, or any combination of these factors. These large fires can be more dangerous to people and more destructive to property, vegetation, and wildlife.

We summarize potential consequences from O1 on an annualized basis in Table II-4.[26] Serious injuries and fatalities are associated with firefighters and members of the public that could be physically injured during a wildfire event. Financial costs are associated with property damage, firefighting costs, and land restoration costs. Reliability reflects outage events associated with fires. Consequences are shown in natural units (NU), which are defined as Serious Injuries and Fatalities for Safety, Customer Minutes of Interruption (CMI) for Reliability, and US Dollars for Financial. On a mean basis, this outcome is modeled to result in 7.4 serious injuries, 0.89 fatalities, 380,000 customer minutes of interruption, and $177 million in financial consequences. Similarly, on a tail-average basis, this outcome is modeled to result in 53.2

[26] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*), and WP Ch. 10, p. 10.52 *(SME Qualifications)* for additional detail on model inputs and rationale.

serious injuries, 6.4 fatalities, 2.7 million customer minutes of interruption, and $1.3 billion in financial consequences. The similar tables for Outcomes 2 – 4 also display this type of information for their respective consequences.

Table II-4 – Outcome 1 (Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres): Consequence Details[27,28]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	7.4	0.89	380,083	$177,046,382
	NU - Tail Avg	53.2	6.41	2,731,289	$1,272,262,531

2. O2 – Wildfire Red Flag Warning In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 31.0% of wildfire events evaluated result in this outcome. Table II-5 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

[27] As of October 19th, 2018, CalFire Redbook data had not been released for 2017. However, several significant 2017 fires have been publically reported by CalFire in news releases to be caused by Electrical Power, and included within this analysis. Please refer to Section VIII-B for additional description of data availability.
[28] http://www.usfa.fema.gov/downloads/xls/statistics/us_fire_loss_data_sets_2006-2015.xlsx

Table II-5 – Outcome 2 (Wildfire Red Flag Warning In Effect Less Than 5,000 Acres): Consequence Details

Outcome 2		**Consequences**			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.1	0.01	1,709,923	$689,707
	NU - Tail Avg	0.2	0.02	2,983,897	$1,205,427

3. O3 – Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 0.2% of wildfire events evaluated result in this outcome. Table II-6 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-6 – Outcome 3 (Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.7	0.09	96,120	$40,484,491
	NU - Tail Avg	7.0	0.84	961,196	$404,844,913

4. O4 – Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 68.1% of wildfire events evaluated result in this outcome. Table II-7 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-7 – Outcome 4 (Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres): Consequence Details

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.2	0.02	3,760,369	$1,516,932
	NU - Tail Avg	0.3	0.04	5,596,130	$2,261,676

III. Compliance & Controls

SCE has programs and processes in place today that serve to reduce the frequency of the risk materializing, or the impact level of a risk event should it occur. These activities are summarized in Table III-1, and discussed in more detail thereafter.

Table III-1 – Inventory Compliance & Controls[29,30,31]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$0.0	$84.3
C1	Overhead Conductor Program (Bare + Covered)	D1a, D1b, D1d, D2b, D2f	-	-	$138.7	$0.0
C1a	Overhead Conductor Program - (Bare Only)	D2b, D2f	-	-	$138.7	$0.0
C2	FR3 Overhead Distribution Transformer	D2g	-	-	$0.0	$0.0

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

A. CM1 – Vegetation Management

Vegetation Management includes pruning and removing trees that are in proximity to transmission and distribution high voltage lines. Vegetation Management also encompasses weed abatement around select overhead structures that may pose a hazard to power lines. These activities are mandated by regulation. This compliance-related work is distinct from the Expanded Vegetation Management mitigation developed and requested in the GS&RP mitigation portfolio, which although absolutely critical, is not expressly required by rule or regulation at this time. This Expanded Vegetation Management is represented in M5.

SCE manages vegetation in accordance with several regulations, including General Order (GO) 95 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. SCE engages approved contractors to trim and remove trees and weeds, and engage in other vegetation management activities that comply with these requirements.

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[29] Within control and mitigation numbering, "a" and "b" designations indicate a change to a subset of overall program configurations. For example, the C1a OCP control explores the reversal of a standards change that is planned for 2020 to utilize covered conductor across all OCP scope in HFRA. M1a and M1b explore covered or bare conductor options in a subset of HFRA. 2017 recorded costs for OCP are duplicated for C1 and C1a as SCE has just one OCP program in the recorded period.
[30] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).
[31] Control C2 does not show recorded costs, since it is associated with incremental costs for a change of standard for an existing program.

All of the trees in inventory are inspected annually. During these inspections, any trees or vegetation that need to be remediated to maintain the required distances from high-voltage lines are then scheduled to be pruned or removed. In addition, hazard trees, such as overhangs in HFRA, and damaged or diseased trees are also identified for pruning or removal. Sometimes we must trim trees more frequently to continue to meet the Commission's requirements for tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle infestation or resulting from California's Drought Order. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve. The estimated number of dead trees statewide is estimated at over 129 million, with over 14 million dead trees in high-hazard zones.[32]

B. C1 and C1a – Overhead Conductor Program (OCP)

C1 and C1a contemplate the benefit of deploying SCE's OCP program in HFRA. C1 captures the benefit of deploying OCP in HFRA using covered conductor.[33]

C1 will initially leverage bare conductor from 2018-2020 and transition to covered conductor for 2021-2023. SCE implemented a standards change in July 2018 to require new OCP projects in HFRAs to use covered conductor, which will provide additional wildfire risk benefits compared to bare conductor. Standards changes are applied to all new designs initiated after the standard is published. Because standards do not apply retroactively, inflight projects at various stages of completion with operating dates as late as 2020 will be built with bare conductor in HFRAs.

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

[33] Please see Section IV.A for a more detailed description of covered conductor.

C1a captures the benefit of deploying OCP in HFRA using only bare conductor for the entire period 2018-2023. Covered conductor is described in more detail in Section IV – Mitigations.

In SCE's 2018 General Rate Case (GRC),[34] we proposed the OCP as a new program to address the public safety risk associated with wire-down events. SCE's OCP includes both reconductoring and installation of branch line fuses (BLFs). When OCP projects are performed in HFRA, these projects also will have wildfire risk reduction benefits as well.

Reconductoring and branch line fusing are intended to target and remedy overhead conductor susceptible to exceeding its short circuit duty rating.[35] The OCP also addresses damaged conductors using visible corrosion detection, and evaluates splice counts on the line as indicators of prior damage. As part of OCP, we also address crossarms, poles, connection hardware, and other damaged equipment along the path of the conductor being remediated.

Historically, SCE's distribution circuits were designed with larger conductor closer to the substation (feeding the circuit) and progressively smaller conductors as one proceeds further from the substation. This design approach was based on economics principles, and the fact that a circuit carries less current as it moves away from the substation.

The smaller conductor, when installed, was sized appropriately for the load. However, this smaller conductor is also inherently more susceptible damage from contact with metallic balloons, animals, vegetation, and other drivers listed in Table II-2 as the available SCD increased over time due to system upgrades. By replacing this smaller conductor with larger conductor, we reduce the risk of failure.

Installing branch line fuses protects against fault energy-related conductor failure. Fusing a line limits the amount of energy delivered to a fault. It does so by interrupting the current faster than the next upstream device, often the circuit breaker at the substation, keeping the conductor within its SCD rating. SCE's OCP includes fusing tap lines to mitigate the risk of overhead conductor failure.

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

[35] When reconductoring, SCE uses a minimum wire size of 1/0 Aluminum Conductor Steel Reinforced (ACSR), with 1/0 ACSR used predominately for tap lines, and 336 ACSR used predominately for main line sections.

1. Drivers Impacted

The OCP (C1) impacts Driver D1 (Contact from Object) with the covered conductor standards change starting in 2021,[36] and also impacts Driver D2 (Equipment Cause) for all years over the 2018-2023 RAMP period.[37] The OCP (C1a) impacts only Driver D2, for all years over the 2018-2023 RAMP period.[38]

Based on engineering analysis and demonstrated material performance, replacing small wire with large wire will increase the conductor's ability to withstand higher short circuit duty. This makes the conductor less susceptible to failure from faults on the line. Similarly, installing BLFs will reduce the risk of failure by quickly interrupting the flow of current when fault conditions are present.

Reconductoring with bare wire *will not* reduce the frequency of contact from object faults. Contact from objects are external, or random, events that will continue to occur regardless. However, reconductoring with covered conductor *will* reduce the frequency of contact from object faults.

2. Outcomes & Consequences Impacted

The OCP (C1 and C1a) will not directly impact outcomes or consequences in the risk model.

C. C2 – Ester Fluid (FR3) Overhead Distribution Transformer

This control will replace existing overhead distribution transformers (which are primarily filled with mineral oil) with overhead distribution transformers filled with ester fluid. Envirotemp FR3 Fluid, or ester fluid, is a derivative of renewable vegetable oil, and has a higher flash point rating than mineral oil.[39] This decreases the likelihood that the fluid and/or fluid vapors will ignite and stay lit during a catastrophic event. This in turn reduces the chance of igniting surrounding brush and/or other flammable material surrounding the pole and transformer.

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[36] The specific sub-drivers impacted include D1a (Contact From Object – Animal), D1b (Contact From Object – Balloons), and D1d (Contact From Object – Vegetation).
[37] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[38] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[39] According to Safety Data Sheets, Petroleum Electrical Insulating Oil (or transformer mineral-oil) has a Cleveland Open-Cup (COC) flashpoint rating of 145°C. Envirotemp FR3 Fluid has a COC flashpoint rating of 310°C.

Also, distribution transformers that are filled with ester fluid can operate at higher temperatures than mineral oil-filled distribution transformers, and still have the same life as the mineral oil-filled transformer. This increases the transformer kVA capacity. This added kVA capacity will prolong the life of the transformer's internal insulation system and improve summer heat storm performance.

As of April 2, 2018, all standard pole-type transformers supplied to SCE are now filled with ester fluid. Ester fluid-filled transformers are currently being installed to support new construction as well as transformer replacements driven by normal work processes (e.g., identified as deteriorated, overloaded, cutover to a higher voltage, etc.). These installations are not occurring on a proactive basis based on oil content alone. The full benefits and reduced risk of fire ignition by distribution transformers across the SCE system is expected to increase over time as the percentage of FR3-filled transformers rises across the system, including in HFRA areas.

1. Drivers Impacted

The use of FR3 transformers (C2) impacts sub-driver D2g (Equipment/Facility Failure – Transformer), as the new transformer fluid, with the higher flash point, will reduce the chance that a catastrophic failure will cause a fire ignition.

2. Outcomes & Consequences Impacted

Using FR3 transformers (C2) will not directly impact outcomes or consequences in the risk model.

D. Additional Controls Discussed in other chapters

In Chapter 12 (Climate Change), SCE models a control that likely also provides certain benefits to this Wildfire chapter. This is C2 – Fire Management Program. Table III-2 describes the interaction of Fire Management Program benefits between the two chapters.

Table III-2 – Control Included in Chapter 12 (Climate Change) with Providing Wildfire Benefit

Chapter 12 - Climate Change Chapter Control	Control Description	Likely Benefits for Wildfire Chapter
C2 – Fire Management Program	SCE maintains a Fire Management Team that includes fire management officers having experience as fire fighters and/or linemen. These fire management officers perform these activities: • Conduct training on electrical safety for first responders. • Proactively monitor fire threats to SCE infrastructure, coordinate with SCE Fire IMTs, and assist in restoration activities involving electrical assets. • Coordinate planning and response operations with external agencies and first responders. • Monitor climate change impacts on hazardous fuel (grass, heavy brush, chaparral, etc.) build-up that increase the severity and duration of wildfire events. Support project teams focus on hardening the grid to accommodate climate change drivers.	These efforts can reduce reliability impacts and increase the safety of our crews, first responders, and customers. For additional detail, please refer to Chapter 12 (Climate Change).

IV. Mitigations

Besides the controls detailed in Section III, SCE has identified potential new and innovative ways to mitigate this risk. These mitigations are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[40]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted
M1	Wildfire Covered Conductor Program	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1b	Underground Conversion	D1 - All, D2 - All, D3, D4	-	-
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	-	O1, O2	All
M3	PSPS Protocol and Support Functions	-	O1	All
M4	Infrared Inspection Program	D2f	-	-
M5	Expanded Vegetation Management	D1d	-	-
M6	Microgrids	-	All	R
M7	Enhanced Situational Awareness	-	All	All
M8	Fusing Mitigation	D2b, D2d, D2e, D2f	-	-
M9	Fire Resistant Poles (M1 Scope)	-	All	All
M9a	Fire Resistant Poles (M1a Scope)	-	All	All
M9b	Fire Resistant Poles (M1b Scope)	-	All	All

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

A. M1 and M1a[41] – Wildfire Covered Conductor Program

Installing covered conductor on SCE's system is an enhanced mitigation technique for reducing wildfire ignition risks, as compared to bare conductor. Prior to 2015, there were

[40] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).

[41] For RAMP modeling purposes, M1 captures the benefits of the covered conductor under WCCP, while M1a utilizes bare conductor for portions of circuits that meet SCD criteria and covered conductor for portions of circuits that meeting CFO criteria.

limited installations of older vintage covered conductor on SCE's system.[42] These limited installations typically occurred in heavily wooded areas with a history of outages (often related to animals and vegetation) and with limited access for tree pruning.

The covered conductor SCE is proposing to deploy as part of this mitigation utilizes a robust three-layer design. The design can prevent arcing caused by contact with a tree limb, conductor-to-conductor contact, or contact with a metallic balloon. In addition, the covering on the conductor (the "insulation") helps reduce the frequency of contact-related circuit interruptions that can lead to wire-down events. The insulation can also reduce the potential for electrocution in a wire-down event where the conductor remains energized. Finally, covered conductor will be sized to accommodate expected levels of fault current should faults occur, regardless of cause. This will also reduce the likelihood of wire-down events.

SCE's Wildfire Covered Conductor Program (WCCP) includes: (a) deploying covered conductor along with fire-resistant poles[43] when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.[44] The WCCP is related to, but distinct from, the current OCP. Both programs address some of the same root causes of wire-down events. But OCP addresses safety and reliability at a more general level, while WCCP specifically focuses on enhancing system safety and resiliency in light of wildfire risks.

While both programs will have some related benefits,[45] the programs necessarily differ in priorities and work practices. WCCP seeks to prevent faults that can cause ignitions in HFRA and prioritizes circuits with higher wildfire risk. OCP, on the other hand, aims to prevent wire-down events that create public safety hazards, and focuses on circuits with higher short circuit duty (SCD) values that serve more customers, typically in urban areas.

As part of our WCCP efforts, SCE developed a circuit prioritization methodology to guide the order in which circuits would be hardened with covered conductor.[46] This approach lets SCE

[42] See A.18-09-002, Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program (Section IV.B.1) for additional details regarding SCE's Wildfire Covered Conductor Program, historical use of covered conductor, and current proposed covered conductor.
[43] WCCP includes deploying covered conductor, installing fire-resistant poles, and remediating tree attachments. For RAMP modeling purposes, fire-resistant poles were modeled as a standalone mitigation.
[44] Older construction in the forested areas of SCE's service area sometimes made use of existing trees to carry conductor rather than a separate utility pole. These are called "tree attachments."
[45] WCCP will have some safety and reliability benefits and OCP will have some wildfire benefits.
[46] Please refer to WP Ch. 10, pp. 10.43-10.46 (*Circuit Deployment Prioritization*)

maximize the risk reduction benefits over time and prioritize those circuits with greater wildfire risk; this includes ignition frequency, ignition consequence, and estimated mitigation effectiveness when covered conductor is installed.

SCE has approximately 4,500 distribution circuits in its service territory. About 1,300 of these circuits traverse HFRA. WCCP will focus on certain spans located in HFRA that pose the greatest risk of fire ignition on these approximately 1,300 circuits. SCE has identified approximately 4,000 circuit miles of bare overhead conductor in HFRA that appear to be best suited for reconductoring with covered conductor[47] to mitigate contact-related faults and alleviate the risk of wire-down events during fault conditions.

These circuit miles encompass three main fire ignition risk areas within HFRA: (1) spans with vintage small conductor at risk of damage during fault conditions; (2) spans with elevated risks of faults caused by contact from object (vegetation-related); and (3) spans with elevated risks of non-vegetation-related contact from object faults.

While M1 involves reconductoring *solely with covered conductor*, M1a is a hybrid mitigation. In M1a, portions of distribution circuits that meet SCD criteria (vintage small conductor as described in item 1 above) will be reconductored *with bare conductor.* Other portions of circuits that meet the CFO criteria (as described in items 2 and 3 above) will be reconductored *with covered conductor*.

Likewise, M1b – discussed in the section below – also involves a hybrid approach. But here, the combination is different. M1b consists of a combination *covered conductor and underground conversion*.

Table IV-2 summarizes the differences in technology used within each of the M1, M1a and M1b mitigations.

Table IV-2 – Mitigation Scope for M1 Options

Mitigation	Short Circuit Duty Scope (945 circuit miles)	Contact From Object Scope (1,481 circuit miles)
M1	Covered Conductor	Covered Conductor
M1a	Bare Conductor	Covered Conductor
M1b	Covered Conductor	Undergrounding

[47] SCE plans to complete deploying covered conductor for approximately 4,000 circuit miles by 2025.

Currently, SCE removes conductor and equipment attached to trees when these items are identified during vegetation clearing or in response to a trouble call. Conductor installed on a tree is vulnerable due to its close contact with the tree and the risk that the tree will die. A dead tree can fall, and is more susceptible to burning. SCE has approximately 1,640 tree attachments currently in service in HFRA as part of its primary overhead distribution system. For both (M1) and (M1a), SCE will replace tree attachments together with deploying covered conductor; the work may include installing new poles.

1. Drivers Impacted

The WCCP (both M1 and M1a) impacts the same drivers addressed by the OCP, namely: D1 – Contact from Object, and D2 – Equipment / Facility Failure.[48]

M1 is modeled with a higher impact on Driver D1 (Contact from Object) than M1a. With M1, we would install more covered conductor, which should reduce the frequency of contact-related faults.

2. Outcomes & Consequences Impacted

The WCCP will not directly impact outcomes or consequences in the risk model.

B. M1b – Underground Conversion

As shown in the Table IV-2 above, M1b modifies M1 by utilizing underground conversion instead of covered conductor for portions of circuits that meet the CFO criteria; portions of circuits that meet the SCD criteria would still be reconductored with covered conductor.

To date, SCE has not performed any overhead to underground conversions to mitigate wildfire risk. SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C.[49] In cities where undergrounding is required, SCE will install all-new construction that complies with the city's requirements. This would be a new mitigation activity for SCE, because currently there are no programs which specifically target converting overhead to underground lines to address wildfire risks.

An overhead to underground conversion involves removing all above-ground equipment, such as poles, conductor, transformers, switches, etc. We then replace the above-ground equipment by installing underground conduit, cable, vaults, manholes, transformers, switches,

[48] Specifically, M1 and M1a affects the following sub-drivers: D1a (Contact from Object – Animal), D1b (Contact from Object – Balloons), D1d (Contact from Object – Vegetation), D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[49] See https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

etc. This mitigation would target circuits, or sections of circuits, where the risk of damage would outweigh the relatively high cost of conversion.

Undergrounding electric facilities can be technically challenging and may require multiple designs based on specific geographic factors. For example, portions of SCE's San Joaquin district are heavily-forested and sparsely populated. These areas have overhead circuits installed away from roadways, and traversing hills and other challenging terrain. This makes access by SCE personnel difficult and time-consuming. In some instances, this type of circuit construction uses trees to carry conductor. As we eliminate circuits with tree attachments, we will rebuild along the road to foster our ability to restore service in snowy conditions. When conditions prevent us from safely placing overhead lines (such as no road shoulder, or sloping or rocky terrain), we would underground in the road.

1. Drivers Impacted

This mitigation impacts all drivers and sub-drivers in the risk model. Since this mitigation would eliminate portions the overhead system, all drivers would be impacted by the undergrounding mitigation.

2. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

C. M2 – Remote-Controlled Automatic Reclosers (RARs) and Fast Curve Settings

M2 will perform two related efforts within HFRA: (1) installing 98 additional RARs with Fast Curve operating setting[50] in HFRA; and (2) updating the relay and/or settings on approximately 930 existing RARs and 1,164 circuit breakers with Fast Curve operating settings.

RARs are protective devices applied to mainline conductor that can automatically interrupt faults. The RARs will provide faster or more selective "fault clearing" to further reduce fire ignition risks and lessen service interruptions for SCE customers. These new RARs will provide fault interrupting capabilities with recloser blocking[51] and Fast Curve settings during Red Flag

[50] Fast Curve Setting modifies the relay fault detection curve, providing faster fault detection and interruption. Once the updated settings are installed, the Fast Curve can be remotely activated or de-activated through SCE's monitoring and control radio network.

[51] Under normal circumstances, SCE automatically recloses its circuits after they are de-energized from a fault interruption. Automatic reclosing is used to allow electric service to be restored quickly following a fault which is momentary or temporary. During Red Flag Warning conditions, SCE's Distribution Control Center remotely blocks the automatic reclosing relay for CBs and RARs within its HFRA. For these circuits, the reclosing relay is disabled and, following a fault, the circuit remains de-energized until a

Warnings. Additionally, they will provide isolation points to help implement Public Safety Power Shutoffs (PSPS). In particular, SCE's PSPS protocols will benefit from additional RARs, because less customers will be impacted if SCE can de-energize a relatively smaller portion of a circuit.

Additionally, during Red Flag Warning conditions, Fast Curve settings will be remotely enabled by SCE's Distribution Control Center operators, resulting in typical faults being cleared more quickly. Fast Curve settings reduce fault energy by increasing the speed with which a relay reacts to most fault currents.[52] Compared to conventional settings, reduced fault durations anticipated with Fast Curve operating settings are expected to reduce heating, arcing, and sparking for many faults.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition outcomes (O1 and O2). Given the RAMP model structure, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling purposes, SCE represented this mitigation as impacting all consequences associated with O1 and O2.

Additionally, SCE notes that reducing wildfire risk by implementing more sensitive protective settings and the blocking of reclosing, will increase reliability consequences associated with faults that do not ignite wildfires. Since non-wildfire related faults are out of scope, the negative reliability impact of M2 is not reflected in the results of this risk analysis.

D. M3 – Public Safety Power Shutoff (PSPS) Protocol and Support Functions

SCE has recently instituted a formalized Public Safety Power Shutoff (PSPS) protocol where it may de-energize selected distribution circuits in HFRA[53] to reduce the chances of fire ignitions during the most extreme and potentially dangerous fire conditions. A PSPS event represents the

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

[52] The Fast Curve reduction in fault energy is dependent on the fault magnitude and existing settings; as a general estimate, the configuration is expected to reduce fault energy by 50 percent.

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

mitigation of last resort in a line of defenses against fire risk. This practice is aimed at keeping the public, SCE customers, and SCE workers safe. SCE currently considers many factors before de-energizing, including:

- Input from in-house meteorologists about current and forecast fire weather conditions;
- Wildfire fuel characteristics, and moisture levels of vegetation surrounding utility infrastructure; and
- Input from first responders and emergency management personnel regarding the potential impacts to ongoing evacuations, essential facilities/services, and at-risk customers.

In addition, SCE will deploy line patrol crews to assess circuit conditions before de-energizing. Prior to restoring service, we will also use these crews to confirm that it is safe to re-energize.

Public outreach is an important component of a utility’s pre-emptive power shutoff protocol. SCE will complete outreach efforts with a number of stakeholders, including: state agencies, tribal governments, local agencies, and representatives from local communities. We will do so to help ensure these stakeholders are informed of the protocol and to solicit their feedback. This outreach will primarily be completed by October 2018, but will continue as needed to keep key stakeholders informed of the program. SCE continues to conduct community meetings and workshops to increase stakeholders’ awareness and understanding of SCE’s PSPS protocol, as well as to obtain feedback.

Additionally, SCE has procured a software solution to enhance its customer notification capabilities in order to more quickly and efficiently deliver notifications to customers before, during and following PSPS events. Specialized capabilities of this solution include:

- Ability to more quickly create and deliver customized outage communications in the customers’ digital channel(s) of preference (Smartphone, SMS text, Email, and TTY);
- Bandwidth to deliver up to 1.5 million digital outage communications within one hour; and
- Ability to provide near real-time notifications and access historical records on notifications sent to customers.

To lessen the outage impacts to customers during PSPS events, on a case-by-case basis SCE will consider deploying available temporary mobile generators for Essential Use[54] customers to help maintain electric service for essential life, safety, and public services. Additionally, SCE plans to procure and deploy eight portable community power trailers to augment SCE's current customer outreach efforts during these events. Deploying the trailers will be prioritized based on factors like customer density and outage impact. These trailers can withstand high wind speeds associated with extreme fire conditions. The trailers can also provide local communities with charging stations for their phones, laptops, tablets, and other personal devices they rely upon to receive updates about the outage, monitor public safety broadcasts, and stay in contact with family and friends.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2).[55] For modeling, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling, SCE represented this mitigation as impacting all consequences associated with O1.

Additionally, SCE notes that reducing wildfire risk by implementing PSPS will increase reliability consequences associated with those circuit interruption events where a wildfire ignition is not avoided. Since non-wildfire related faults are out of scope, the negative reliability impact of M3 is not reflected in the results of this risk analysis.

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[54] Essential Use customers are defined by the Commission as those that provide essential public health, and safety services. *See* General Order 166. Examples include agencies providing essential fire or police services, hospitals and skilled nursing facilities, communications utilities, facilities supporting fuel and transportation services, and water and sewage treatment utilities.

[55] As previously mentioned, forecast fire weather conditions is a key component in the decision process of executing a PSPS event. Additionally, there may be rare instances where SCE will need to de-energize through PSPS without the presence of a Red Flag Warning event.

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E. M4 – Infrared (IR) Inspection Program

1. Description

SCE is developing a biennial Infrared (IR) Inspection Program for overhead distribution lines within HFRA. Inspection findings will be prioritized per SCE's Distribution Inspection Maintenance Program (DIMP) manual and given appropriate system remediation timeframes. The IR program will identify "Hot Spots" on distribution system equipment. Examples of equipment that will be included in the inspection program are splices, connectors, switches, and transformers. Hot Spots are areas where there is a temperature difference between either two phases, or two pieces of metal on one phase. These Hot Spots are not visible to the naked eye, and can only be detected by a trained thermographer using an IR camera. Hot Spots are reliable predictors of future component failures that, if unaddressed, could potentially result in fires and customer outages.

IR inspections will help increase safety by enhancing critical circuit inspections and reducing fire safety hazards caused by potential equipment failures. These IR inspections will also improve reliability.

2. Drivers Impacted

The IR Inspection Program (M4) impacts Driver D2 (Equipment / Facility Failure)[56] by detecting in advance certain types of equipment failure before it occurs.

3. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

F. M5 – Expanded Vegetation Management

M5 expands SCE's vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated.

For example, a 75-foot tall palm tree located 50 feet from electrical facilities not only has the potential to fall into these facilities, but its palm fronds can dislodge and blow into electrical facilities, igniting a fire. While this palm tree meets all mandated compliance clearances and is not dead or dying, SCE may still identify it as a potential risk to be mitigated by either removing

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

dead fronds or removing the tree altogether. SCE views this as an important effort in light of increasing winds that have the potential to blow palm fronds and other debris into utility lines from even greater distances.

1. Drivers Impacted

The Expanded Vegetation Management program impacts D1d (Contact From Object – Vegetation) by reducing the frequency of vegetation contact-related faults.

2. Outcomes & Consequences Impacted

The Expanded Vegetation Management program (M5) will not impact outcomes or consequences in the risk model.

G. M6 – Microgrids

A microgrid is a collection of generation sources (including conventional and renewable generators, demand side management, and energy storage) and loads capable of operating in parallel with, or independently of, the main power grid. In remote areas, especially those in rural or forested areas, electricity may need to pass over utility equipment located in HFRA. Microgrids could provide greater resiliency to critical customers, water pumping, and hospitals in these areas during times when grid power may need to be proactively shut off to minimize the potential for wildfire ignition during inclement weather conditions. Microgrids are not intended as a permanent service solution, but rather can serve as a backup power source to provide service continuity during critical periods.

1. Drivers Impacted

This mitigation provides resiliency during a PSPS event and will not mitigate any of the drivers. Therefore, Microgrids (M6) will not impact driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

This mitigation will impact the reliability consequences associated with all outcomes, because it provides for faster temporary restoration of power to customers during interruption events.

H. M7 – Enhanced Situational Awareness

M7 will enhance our wildfire situational awareness by deploying weather stations and High Definition (HD) cameras across our HFRA, a high-resolution weather model, and a high-performing computing platform for fire potential index modeling. Situational awareness is an integral part of emergency management, because SCE needs a granular understanding of what is happening across its service area prior to and during emergency events. SCE is further enhancing its situational awareness capabilities to address increasing fire risks throughout its service area. SCE is focused on accessing more detailed information about wildfire risk at the individual circuit level, to better understand how weather conditions might impact utility infrastructure and public safety in high fire risk areas.

SCE intends to enhance its existing weather models by installing additional weather stations on circuits within HFRA. These additional weather stations will enhance the resolution of existing weather models and provide real-time information to help make key operational decisions during potential fire conditions, including PSPS deployment.

When installed, weather stations use various sensors and communications to provide meteorologists with real-time weather data. This includes temperature, relative humidity, dew point, wind speed, wind direction, wind gust behavior, wind gust direction, and other variables.

The weather stations' capabilities include a datalogger, a central component of the station which measures signals coming from the weather station sensors.

Through October 2018, SCE has installed over 110 new stations. SCE's fire meteorologists will continue identifying potential locations for up to approximately 850 total weather stations by 2020.

SCE is installing pan-tilt-zoom (PTZ) HD cameras throughout its HFRA to enable fire agencies and SCE personnel to more quickly identify and evaluate emerging wildfires. Deploying HD cameras throughout our HFRA will enhance SCE's situational awareness capabilities and enable emergency management personnel, including fire agencies, to more swiftly respond to emerging wildfires. In particular, HD camera images save time in verifying and assessing a fire's severity as compared to sending fire crews to perform this assessment.

HD camera views will transmit into SCE's Situational Awareness Center, and will be used by our Incident Management Teams (IMT) to decide how to deploy crews and make other operational decisions, such as PSPS activation. These HD cameras will help mitigate potential safety risks to the public and prevent damage to electric infrastructure. Between 2018 and 2020, SCE is planning to install up to 160 PTZ HD cameras on approximately 80 towers. This will provide coverage of nearly 90 percent of SCE's HFRA.

SCE has contracted with IBM to access a high-resolution weather model. The model will forecast weather parameters such as temperature, wind speed and gusts, humidity, precipitation and fuel characteristics. It will provide these benefits:

- Enhanced resolution and more accurate forecast data to better inform deploying SCE's PSPS protocol;
- Severe-weather forecasting including wind, thunderstorms, heavy rain events and extreme temperatures;
- Visualization of weather conditions and forecasts around SCE infrastructure; and
- Overall support to SCE's IMT in developing HFRA forecasts and fire response plans.

SCE intends to deploy a high-performance computing platform to improve its ability to scientifically quantify the risk of wildfire ignitions in different geographic regions throughout its service area. SCE will procure advanced computer hardware and deploy state-of-the-art software that will run a sophisticated Fire Potential Index model. The model will account for various factors including weather, live fuel moisture, and dead fuel moisture to assess the level of risk of wildfire ignitions.

Our efforts here will also enable software to analyze decades of data for fuel and weather characteristics from past wildfire ignitions, and compare and contrast those variables against current conditions to forecast the Fire Potential Index. The output from this model will inform operational decisions, implement work restrictions, and optimize resource allocation for emergency situations.

SCE will implement an Asset Reliability and Risk Analytics program to build capabilities in predicting an asset's overall wildfire-related risk and prioritize work, repairs, and/or replacement(s) to minimize potential wildfire ignitions.

Additionally, the state's substantially increasing fire risk means that SCE must respond to more frequent and prolonged fire threats throughout its service area. SCE will augment its Business Resiliency staff with four full-time positions to accommodate the increased demands.

1. Drivers Impacted

This mitigation focuses on improving situational awareness and therefore will not directly impact any of the drivers in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve situational awareness related to wildfires in the SCE system, M7 will impact all consequences related to wildfire outcomes in the risk model.

I. M8 – Fusing Mitigation

M8 plans to install or replace fuses at approximately 15,613 fuse locations in two main groupings. The 15,613 figure represents the number of branch line locations in the HFRA. This mitigation should ensure that all locations are addressed. First, we will install new Current Limiting Fuses (CLFs) at 8,855 branch line locations. Second, we will replace existing fuses with CLFs at up to 6,758 existing fuse locations on circuits that traverse the HFRA. This program should reduce the risk of fire ignitions associated with SCE's distribution lines and equipment by reducing fault energy. We plan to complete this work during the 2018-2020 timeframe.

SCE has traditionally applied fuses on branch line locations to improve electric service reliability by limiting the number of customers affected by a fault. This practice has resulted in fuse application on approximately 43 percent of the HFRA-related branch circuits. This mitigation will result in fuse application of approximately 100% of HFRA-related branch circuits when complete. SCE has traditionally used conventional expulsion type fuses (conventional fuses) for fuse applications. For this M8, SCE intends to utilize CLFs instead of conventional fuses for most applications in the HFRA. We selected CLFs for this application because they provide faster fault clearing for most faults and reduce fault energy, compared to a conventional fuse.

Table IV-3 illustrates the groups of fuse installations and replacements.

Table IV-3 – Fuse Groups

Group	Sub-group	Fuse Locations
Installing new CLFs	N/A	8,885
Replacing existing fuses	Conventional expulsion type	1,656
	Conventional non-expulsion type	5,102
Total		**15,613**

For the first group (installing new CLFs), M8 will install new fuses on distribution circuit branch lines in HFRA which are not presently fused, or that may benefit from further segmentation via additional fuse installations. The program will also replace certain existing conventional fuses with CLFs to further minimize ignition risk.

The second group (replacing existing conventional fuses) can be divided into two sub-groups. The first sub-group involves replacing existing expulsion type fuses which require brush clearing at the base of the pole to remove potentially flammable vegetation.[57] The second sub-

[57] This aligns with the CalFire Power Line Fire Prevention Field Guide.

group involves replacing existing conventional non-expulsion type fuses that would benefit from the current limiting technology for energy reduction, but would otherwise be exempt from brush clearing per CalFire's Power Line Fire Prevention Field Guide.

1. Drivers Impacted

SCE's Fusing Mitigation Program impacts Driver D2 - Equipment/Facility Failure.[58] It does so by de-energizing branch lines that experience faults and reducing the fault energy that can damage conductors, insulators, or connectors.

2. Outcomes & Consequences Impacted

The Fusing Mitigation (M8) will not directly impact outcomes or consequences in the risk model.

J. M9, M9a, M9b[59] – Fire-Resistant Poles

At locations where SCE is installing covered conductor in HFRA and pole replacements are required, SCE will use fire-resistant composite poles, where appropriate, instead of traditional wood poles. The variation in mitigation scenarios for M9 (M9, M9a, and M9b) reflect different volumes of installing fire-resistant poles. The volumes of these installations are commensurate with the volumes of covered conductor deployment in M1, M1a, and M1b, respectively. Table IV-4 illustrates this relationship and the number of pole installations contemplated for this mitigation.

Table IV-4 – Covered Conductor & Fire-Resistant Pole Deployment Scenarios

Wildfire Conductor Mitigation Variant	Conductor Type and Volume (circuit miles)	# of Fire-Resistant Poles Modeled in M9 Variant
M1 *(All Covered)*	Covered Conductor - 2,426	27,513
M1a *(Bare + Covered)*	Covered Conductor - 1,481 Bare Conductor - 945	23,940
M1b *(Covered + Underground)*	Covered Conductor – 945	11,060

[58] Specifically, M8 impacts the following sub-drivers: D2b (Equipment/Facility Failure – Conductor), D2d (Equipment/Facility Failure – Fuse), D2e (Equipment/Facility Failure – Insulator), and D2f (Equipment/Facility Failure – Splice/Connector/Clamp).
[59] For RAMP modeling purposes, M9a corresponds to the number of poles requiring replacement that are associated with M1a bare conductor alternative, while M9b corresponds to the number of poles requiring replacement with the M1b undergrounding alternative.

These poles are specifically designed to withstand wildfires; use of the poles will harden the distribution system. This increases the chances that SCE equipment, including conductor, will remain in the air should a wildfire occur, which will afford multiple benefits. First, the equipment is less likely to be damaged if it is out of the path of the fire. Second, with less damage, SCE can re-energize more quickly after a wildfire event. Finally, if the utility equipment remains intact, then members of the public and first responders are safer.

SCE has experience with similar composite poles. Compared to steel poles, composite poles are non-conductive and resistant to corrosion. And compared to wood poles, composite poles are less susceptible to wildlife damage (e.g., woodpeckers), rotting, and fires, and are also lighter in weight and can carry more load (when compared to wood poles of the same class and size). In general, composite poles are preferred to wood poles in several contexts, such as restricted vehicle access (for sectional composite poles) and areas of accelerated pole degradation.

The composite poles SCE plans to install are manufactured using polyurethane resin and E-glass fiber to create a fiber-reinforced polymer (FRP) laminate. Manufacturer testing has proven that the laminate is self-extinguishing (i.e., fire-resistant). In addition, a shield manufactured from the same fire-resistant material is wrapped around the composite pole sections at the manufacturing plant. When the pole is installed, the shield is embedded 12 inches below the ground line of the final grade. Manufacturer testing has shown[60] that the shield will increase fire resistance, enabling the pole to withstand an "extreme" wildfire.[61]

1. Drivers Impacted

This mitigation is focused on provide resiliency during a wildfire event and therefore will not reduce any driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve grid resiliency related to wildfires in the SCE system, M9 will impact all outcomes and consequences in the risk model.

[60] RS Technical Bulletin: 17-010, *RS Poles and Fire Shields Fire Performance*, at p. 1 (February 1, 2018), *available at* https://www.rspoles.com/sites/default/files/resources/C801---17-010---RS-Poles-and-Shields-Fire-Performance-01-Feb-18.pdf.

[61] *Id.* at p. 13. "Extreme" wildfire exposure is defined as gas temperatures between 800 to 1,200°C and exposure of 121 to 180 seconds. *Id.* at p. 4.

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Sections III and IV and has developed a Proposed Plan of controls and mitigations to pursue, as shown in Table V-1 below. Before discussing these controls and mitigations in detail, certain aspects of the analysis should be placed in context. Examining the relative RSE values shows that, in certain cases, the RSE does not accurately capture certain “real life” factors that are critical in actually choosing mitigations.

First, as SCE discussed in Chapter 1 (RAMP Overview), restricting the evaluation of risk reduction and risk spend efficiency to the 2018-2023 RAMP period can distort the benefits of those mitigations whose benefits will extend significantly beyond 2023. Long-lived assets that are installed during the RAMP period continue to operate and provide risk reduction benefits for many years thereafter. There can be dissonance in RSE comparisons between this type of mitigation compared to an O&M mitigation that has more short-lived benefits. In these cases, the long-lived mitigation will have an RSE that is understated compared to the short-term O&M mitigation.

This dissonance can be seen, for example, when assessing mitigation M1 (Wildfire Covered Conductor Program). The long-term benefits are simply not fully captured in the RSE calculation. To illustrate this, SCE has prepared a long-term pilot analysis. The analysis is found at Appendix 1 to this chapter. In that Appendix, the RAMP analysis is extended out to 50 years rather than the 6-year RAMP period, to estimate the full benefit that the covered conductor assets provide over their useful life. When this longer-term pilot analysis is performed, we see the following results:

- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a mean basis increases 18 times.
- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a tail average basis increases 18 times.[62]

Thus, the RSE comparison is somewhat “skewed” between the longer-lived Wildfire Covered Conductor Program (M1) and the O&M mitigation activities such as PSPS Protocol and Support Functions (M3) and Infrared Inspection Program (M4). The risk reduction benefits of M1 are understated compared to the risk reduction benefits of M3 and M4.

[62] The mean and tail average results have not had any discounting applied.

Also, the RSE necessarily cannot take into account certain operational realities. If one looks solely at the RSE scores, there might be a question as to why SCE doesn't forego the Covered Conductor Plan to a significant degree in favor of the PSPS Protocol and the Infrared Inspection Program. But the respective programs address different aspects of mitigating wildfire risk. In today's increasing wildfire risk environment, a sound wildfire mitigation plan must address conductors. The PSPS Protocol and Infrared Inspection Program do not directly address conductors and conductor performance. Making mitigation decisions in this case purely on RSE would lead to significant parts of the system and potentially significant risk issues being unaddressed.

Moreover, there are also real-life "scalability" issues that the RSE comparison cannot take into account. There are practical limits in how much PSPS and infrared inspections can be deployed. One is a system shut-off protocol; it is a mitigation of last resort. The other is an inspection program that does not, and cannot, actually strengthen system components against wildfires.

Table V-1 – Proposed Plan (2018 – 2013 Totals)[63]

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.39	0.0038
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	2.27	0.0020*	7.22	0.0062*
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0310	3.29	0.1057
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.90	0.0889	6.55	0.3068
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1017	0.93	0.3243
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.20	0.0033
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.84	0.0148	3.14	0.0552
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.73	0.0079
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$ 137	$ -	0.60	0.0043	2.21	0.0161
			Total	$1,609	$447	7.65	0.0037	25.83	0.0126

*Full benefits are not included in 6-yr RSE for M1. If full benefits (without any discount) were included for M1 and it was modeled independently, its RSE would increase by 18 times on both a mean and tail-average basis. Please see Section IX-Appendix 1 to this Chapter, and discussion above, for additional details.

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

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

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

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[63] With respect to M1 (Wildfire Conductor Program): Since Tree Attachments were not modeled, the costs associated with Tree Attachments are not included with the M1 – Wildfire Covered Conductor Program costs. Additional information on the modeling of Tree Attachments is found in Section VIII – Lessons Learned.

There are a few additional items to note when examining the Proposed Plan and the relative mitigation scores:

- *Wildfire Covered Conductor Program [M1]* – the risk benefits are understated to an additional degree because the *benefits* of this mitigation associated with Chapter 5 - (Contact with Energized Equipment) are *not* included in this chapter, but the *full cost* of this mitigation *is* included. The costs are not apportioned out between Wildfire and Contact with Energized Equipment. Each chapter calculates RSE using the full cost of the program.
- *PSPS Protocol and Support Functions [M3]* – the risk benefits are overstated because we do not capture the reliability consequences that occur when de-energizations do not prevent a fire.
- *Enhanced Situational Awareness [M7]* – the risk benefits are understated because they do not capture the positive effects of addressing and mitigating fires that are not associated with SCE.
- *Fire-Resistant Poles [M9]* – the risk benefits are understated because they do not capture the positive effects of addressing fires not associated with SCE.
- *RAMP and GS&RP* – For illustrative purposes, SCE has included a workpaper[64] demonstrating that SCE's GS&RP application and RAMP are aligned. The workpaper shows that comparable GS&RP and RAMP analyses produce similar results concerning the cost efficiency of bare conductor compared to covered conductor. Please also see the discussion found in section V.D below.

A. Overview

As we developed our Proposed Plan, we considered many factors, including:

- The risk assessment outlined in this chapter;
- How various controls and mitigations impact the drivers, triggering event, outcomes, and/or consequences;
- The potential execution speed and timing of mitigations;
- How various mitigations might complement one another or existing controls; and
- Cost.

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

In light of the "new normal" regarding the increasing wildfire risk in SCE's service area, the Proposed Plan represents a comprehensive approach to enhance SCE's existing wildfire mitigation efforts and target the principal drivers that lead to potential wildfire ignitions.

A primary component of SCE's Proposed Plan includes deploying covered conductor (M1). This mitigation targets Driver D1 (Contact from Object). That driver represents the majority of faults that can potentially lead to wildfire ignitions.

As described in Section IV.A (M1 - Wildfire Covered Conductor Program), this mitigation seeks to prevent faults from occurring, and targets three categories of overhead lines: (1) spans with vintage small conductor at greater risk of being damaged during fault conditions; (2) spans with elevated risks of faults due to vegetation-related contact from objects; and (3) spans with elevated risks faults due to non-vegetation-related contact from objects.

The first category, vintage small conductor, is addressed by both SCE's existing Overhead Conductor Program, and SCE's Wildfire Covered Conductor Program. The scope represented by C1 (Overhead Conductor Program Covered 2021-2023) consists of in-flight Overhead Conductor Program projects that will be executed with the bare wire standards in place prior to developing our Wildfire Covered Conductor Program. If we have conductor that meets the criteria for this category but is not included in C1, the mitigation will occur through M1 (Wildfire Covered Conductor Program).

The second category, vegetation-related faults, is addressed by SCE's Wildfire Covered Conductor Program (M1), Expanded Vegetation Management (M5) and Vegetation Management (CM1). Mitigation M5 is incremental to SCE's existing vegetation management practices (CM1), and will further mitigate tree-related ignitions, particularly in areas where covered conductor is not being deployed.

The third category, non-vegetation-related faults, is addressed primarily by our Wildfire Covered Conductor Program (M1). While the primary selection and targeting of the Wildfire Covered Conductor Program focused on mitigating wildfire outcomes and consequences, M1 is expected to provide meaningful improvements in reliability due to its inherent ability to prevent contact from object-related faults (D1).

Remote-Controlled Automatic Reclosers and Fast Curve Settings (M2) and Fusing Mitigation (M8) work with each other, and work in conjunction with our Wildfire Covered Conductor Program (M1), by reducing the energy associated with faults that may occur, regardless of the cause of the fault. These mitigations complement the Wildfire Covered Conductor Program by providing this energy-reducing protective capability for both covered and bare conductor, either during the time period before covered conductor is scheduled to be installed, or for lines that are not targeted for covered conductor deployment. These mitigations provide ignition-related benefits for all types of faults, including those faults that cannot be mitigated by covered conductor.

Infrared inspections (M4) complement the above-mentioned mitigation measures by targeting additional sub-drivers to D2 (Equipment/Facility Failure drivers) that are not mitigated by covered conductor, such as D2a (Capacitor Banks) and D2g (Transformers).

Covered conductor (M1) and infrared inspections (M4) are expected to mitigate Sub-Driver D2f (Splice/Clamp/Connector). Infrared inspections are expected to mitigate these types of failures on lines when the installation of covered conductor is scheduled but has not yet occurred, or when there are lines that are not targeted to have covered conductor.

Using ester fluid FR3 transformers (C2) for both new and future replacements of overhead transformers works in conjunction with infrared inspections, by reducing both the frequency of transformer failures (slower aging of insulation) as well as reducing the potential consequence should a transformer fail (it is less likely that fluid has reached its flash point).

PSPS Protocol and Support Functions (M3) represents SCE's mitigation of last resort and would be exercised if extreme fire conditions develop and existing controls and other proposed mitigations are insufficient to address the emergent risk. Enhanced Situational Awareness (M7) (i.e., high-resolution forecasting coupled with weather stations) is expected to improve SCE's predicting capabilities. It should reduce false positives that result in pre-emptively deploying resources and notifying customers in advance of potential de-energization. We also expect improvement in targeting of PSPS; this should reduce the number of circuits that have to be de-energized. While SCE believes PSPS should be available in extreme circumstances, it is not a long-term solution that can be used in place of the other mitigations shown in the portfolio.

Lastly, Enhanced Situational Awareness (M7) and Fire-Resistant poles (M9) aim to mitigate consequences associated with ignitions that do occur. These mitigations can help reduce the size of wildfires through faster suppression response and faster restoration times should fires engulf SCE infrastructure.

B. Execution feasibility

While some of the mitigations listed in the Proposed Plan have not been previously executed by SCE to the proposed scale, SCE has obtained experience in execution and a greater understanding of cycle times by deploying in advance some portion of the mitigation portfolio. This includes starting to install covered conductor on the highest-priority circuits, and deploying some weather stations and HD cameras in HFRA. The current mitigation deployment timeline evaluates mitigation deployment cycle time, risk reduction, and resources constraints to develop a plan to maximize risk reduction in light of these factors.

While the Proposed Plan represents significant work over the intended time period, it is operationally feasible to increase mitigation deployment capacities and complete this target in addition to its other ongoing and planned activities. In early 2018, SCE created a program management office (PMO) focused exclusively on bolstering public safety and grid resiliency. We created the PMO in part to consolidate SCE's grid-hardening projects to enable more streamlined and expeditious deployment. As part of this effort, SCE carefully considered how quickly it could move forward with its wildfire mitigation portfolio. SCE views the proposed timeline as both operationally feasible and prudent, given the importance and urgency of mitigating wildfire risks and hardening the grid.

C. Affordability

The Proposed Plan has the second-lowest cost of the three plans. The RSE of the Proposed Plan is just slightly lower than the RSE of the Alternative Plan #1, and significantly higher than the RSE of Alternative Plan #2. The Proposed Plan's RSE is less than Alternative #1 because the conductor-related mitigations in Alternative #1 cost less than the conductor-related mitigations in the Proposed Plan, and the RSE of each conductor-related mitigation is lower than the respective portfolio-level RSE.[65]

Using covered conductor is a crucial part of SCE's Proposed Plan. Each of the three plans includes a significant amount of conductor-related controls and mitigations. To understand the differences in underlying cost-effectiveness of the Proposed Plan compared to the alternative plans, it is helpful to examine the RSEs of the conductor-related controls and mitigations.

The conductor-related controls and mitigations are as follows:

- The Proposed Plan uses C1 and M1.
- Alternative Plan #1 uses C1a and M1a.
- Alternative Plan #2 uses C1 and M1b.

The Proposed Plan's conductor related controls and mitigations provide the most value of all conductor-related controls and mitigations in the three plans. The conductor-related

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

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

The Proposed Plan's conductor-related controls and mitigations have a much higher Mitigation Risk Reduction than those Alternative #1. While Alternative Plan #2 has the largest Mitigation Risk Reduction among the three plans for conductor-related controls and mitigations, it also has a much lower RSE than the Proposed Plan and Alternative Plan #1.

Table V-2 below shows a comparison of conductor options and associated risk reduction and risk spend efficiency.

Table V-2 – Comparison of Conductor-Related Mitigation Options

Figures represent 2018 – 2023 totals	**Cost ($M)**	**Mitigation Risk Reduction (Mean)**	**Risk Spend Efficiency (Mean)**	**Miles Addressed[66]**
C1 and M1 *(Proposed Plan)*	$1,263	2.39	1.892E-03	2,680 circuit miles: ***M1:*** *2,426 Covered* ***C1:*** *65 Covered + 189 Bare* *0 underground*
C1a and M1a *(Alternative Plan #1)*	$1,044	1.90	1.820E-03	2,680 circuit miles: ***M1a:*** *1,481 Covered + 945 Bare* ***C1a:*** *254 Bare* *0 underground*
C1 and M1b *(Alternative Plan #2)*	$5,501	2.99	0.365E-03	2,680 circuit miles ***M1b:*** *945 Covered+ 1,481 Underground* ***C1:*** *65 Covered + 189 Bare*

The Proposed Plan assumes deployment of our Overhead Conductor Program with bare conductor in years 2018-2020 and covered conductor in years 2021-2023 (C1), and the Wildfire Covered Conductor Program with covered conductor in years 2018-2023 (M1).

[66] SCE modeled three different conductor types (covered, bare, and underground) across the three portfolios. Different conductor types were selected in each portfolio based on the fault risk areas within HFRA. For example, Alternative Plan #1 evaluates bare conductor use in short circuit duty areas. Alternative Plan #2 evaluates use of Underground Cable for CFO areas.

This fundamentally differs from Alternative Plan #1, which assumes the existing Overhead Conductor Program with entirely bare conductor in years 2018-2023 and the Wildfire Covered Conductor Program with a mix of bare conductor and covered conductor in years 2018-2023.

This is also fundamentally different than Alternative Plan #2, which assumes existing Overhead Conductor Program bare conductor in years 2018-2020 and covered conductor in years 2021-2023, and the Wildfire Covered Conductor Program with a mix of covered conductor and underground conversion in years 2018-2023.

Therefore, the alternative plans reflect two theoretical "modifications" to the Proposed Plan. Alternative Plan #1 represents a "downgrade" of the Proposed Plan, with increased use of bare conductor. Alternative Plan #2 represents an "expansion" of the Proposed Plan, with increased use of underground conversion.

There are similarities in the RSEs of the Proposed Plan and Alternative Plan #1. The modeled scope in the Proposed Plan and Alternative Plan #1 are over 60% identical (each plan includes at least 189 miles of bare conductor and 1,481 miles of covered conductor). Moreover, the variation in scope is less than 40% between the two Plans. The greater RSE of conductor-based mitigations within the Proposed Plan relative to the Alternative Plan #1 would have been more pronounced had the two plans been modeled with a much larger variation in scope. We chose to model with similar scope to evaluate risk scoring while minimizing variability. This is illustrated by *the large variation* in RSE between the Proposed Plan and Alternative Plan #2, which has a significantly different scope (nearly 1,500 miles of underground conversion) and a much clearer difference in RSE (significantly lower RSE).

D. Other Considerations

The mitigation effectiveness discussions in this RAMP chapter differ in several ways from the mitigation effectiveness discussions found in SCE's GS&RP application. The basic mitigation effectiveness **inputs** used within GS&RP and RAMP are closely aligned. But those inputs are **analyzed** using different methodologies. For example, the GS&RP application compares implementations of different conductor mitigations (i.e., bare versus covered versus underground conversion) across the entire HFRA to develop a mitigation effectiveness factor.[67] The application then develops a mitigation-to-cost ratio for each conductor mitigation. It does not combine the different conductor mitigations.

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

In contrast, the RAMP analysis compares different combinations of conductor mitigations (e.g., M1, M1a, or M1b, paired with other mitigations) implemented across a portion of the HFRA. Our RAMP analysis then uses the MARS methodology to calculate a Mitigation Risk Reduction for each portfolio, and then calculates a Risk Spend Efficiency for each portfolio based on cost.[68]

Despite the differences in analytical approaches, the GS&RP and RAMP are aligned. For illustrative purposes, we have included a workpaper that provides an example of applying the GS&RP analysis parameters to RAMP modeling.[69] The workpaper takes the GS&RP analysis of bare conductor versus covered conductor, and runs an equivalent analysis using the RAMP model.[70] As shown in the workpaper, the comparable GS&RP and RAMP analyses produce similar results regarding the cost efficiency of bare conductor compared to covered conductor.

The Proposed Plan is informed by SCE's current capabilities for evaluating and prioritizing mitigation measures, SCE's capabilities to predict potential driver occurrences, and the availability of technologies that can be deployed and are effective at mitigating wildfire risk. In performing these mitigation measures over time, different factors may drive adjustments to the Proposed Plan. These factors include changes to the risk landscape that may be impacted by climate changes and/or mitigation measures implemented by third parties, and improvements in SCE's ability to evaluate wildfire risk across its service territory. Also, policy constraints may restrict SCE's ability to implement desired mitigations or may change how we allocate limited resources.

Lastly, as new technologies emerge, SCE will continue to evaluate the effectiveness of more advanced solutions and how they may complement its existing portfolio of mitigation measures. If new measures prove to be better than existing ones, SCE will work to transition to these improved measures as appropriate.

[68] See Chapter 2 (Risk Model Overview) for additional detail regarding MARS, MRR and RSE.
[69] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).
[70] In running the equivalent analysis, SCE used the same potential frequency of ignition and scope assumptions under which the GS&RP analysis was performed.

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an alternative plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2013 Totals)[71]

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Overhead Conductor Program - (Bare Only)	2018	2023	$ 98	$ -	0.08	0.0008	0.24	0.0025
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	2018	2023	$ 947	$ -	1.83	0.0019	5.87	0.0062
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0311	3.34	0.1073
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0893	6.64	0.3112
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.30	0.1031	0.95	0.3324
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0010	1.24	0.0034
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.19	0.0562
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9a	Fire Resistant Poles (M1a Scope)	2018	2023	$ 119	$ -	0.53	0.0044	1.99	0.0167
			Total	**$1,372**	**$447**	**7.12**	**0.0039**	**24.40**	**0.0134**

A. Overview

Alternative Plan #1 deploys many of the same controls and mitigations as the Proposed Plan. However, a key difference between these two plans is the conductor-related mitigations chosen. Alternative Plan #1 represents a scenario where SCE uses the less expensive, and less effective, bare reconductoring mitigation in place of covered conductor. Alternative Plan #1 (using C1a) deploys bare conductor to target vintage small conductor for work between 2021-2023. In contrast, the Proposed Plan (using C1) deploys covered conductor for that same period.

Alternative Plan #1 also includes M1a, which uses bare conductor for the portions of circuits designated as short circuit duty. In contrast, the Proposed Plan includes M1, which uses covered conductor for those same portions. As discussed in Section V (Proposed Plan) bare reconductoring is less effective than using covered conductor at addressing the wildfire risk.[72] This was a key factor in our decision not to select Alternative Plan #1.

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[71] With respect to M1a: Since Tree Attachments are not modeled, the costs associated with Tree Attachments are not included with the M1a – Wildfire Covered Conductor Program (CFO – CC, SCE Lengths – Bare) costs.

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

Lastly, with respect to fire-resistant Poles, Alternative Plan #1 includes M9a as it corresponds to a reduced number of pole replacements associated with bare conductor. Bare conductor imparts lower gravity and wind loads on the poles as compared to covered conductor. In contrast, the Proposed Plan includes M9, to align with the type and volume of conductor deployed in that plan.

The remaining control (C2) and mitigations (M2 through M5, M7, and M8) remain identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use bare conductor for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of Alternative Plan #1 is very similar to the Proposed Plan.

C. Affordability

Alternative Plan #1 represents the least expensive plan, but also provides the least amount of risk reduction. Bare reconductoring is much less effective than covered conductor in terms of avoiding wildfires. Additionally, the fact that bare reconductoring is unable to mitigate the majority of fault types that are associated with fire ignitions makes Alternative Plan #1 less desirable.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan.

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VII. Alternative Plan #2

SCE developed one other alternative plan, as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 (2018 – 2013 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.38	0.0037
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1b	Underground Conversion	2018	2023	$ 5,399	$ -	2.87	0.0005	9.00	0.0017
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0312	3.26	0.1048
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0896	6.49	0.3040
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1009	0.91	0.3179
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.19	0.0032
M6	Microgrids	2021	2023	$ 10	$ -	0.00	0.0000	0.00	0.0000
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.13	0.0551
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.71	0.0078
M9b	Fire Resistant Poles (M1b Scope)	2018	2023	$ 55	$ -	0.23	0.0042	0.85	0.0155
			Total	**$5,775**	**$447**	**7.90**	**0.0013**	**26.09**	**0.0042**

A. Overview

In Alternative Plan #2, SCE chooses to rely on underground conversion (M1b) and only selects covered conductor for a portion of the targeted circuits (M1b uses underground conversion for the portions of circuits targeted as CFO). In contrast, the Proposed Plan uses covered conductor (M1) for those same portions. Underground conversion is more effective than covered conductor in addressing fire risk, but is substantially more expensive.

Finally, in scoping the use of fire-resistant poles, Alternative Plan #2 selects M9b, while the Proposed Plan uses M9. M9b involves only replacing poles associated with the portions of circuits designated as short circuit duty. Since Alternative Plan #2 includes underground conversion, the scope of M9b will include fewer fire-resistant poles, since none are required for underground portions of the system. Besides the underground conversion, Alternative Plan #2 also include microgrids (M6). Microgrids provide limited incremental reliability benefits to mitigate outage impacts related to PSPS.

Like Alternative Plan #1, the remaining control (C2) and mitigations (M2 through M5, M7, and M8) for Alternative Plan #2 are identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use underground conversion for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of this alternative is significantly impacted by using underground conversions (M1b). As described in Section IV.B, undergrounding overhead lines is considerably more complex than overhead construction, even with covered conductor. This complexity increases the construction time and costs, which impacts available resources.

The complexity also adds to the time needed to mitigate the same quantity of circuit miles. This meaningfully decreases the feasibility of executing Alternative #2. These execution challenges influenced SCE in determining that this alternative was not the most prudent one.

C. Affordability

Alternative Plan #2 gives an increase in risk benefits at substantially increased costs compared to the Proposed Plan. Notably, Alternative Plan #2 reflects the fact that this portfolio (including substantial undergrounding) provides approximately 3% incremental risk benefit on a mean basis compared to the Proposed Plan. But Alternative Plan #2 is approximately *three times as expensive* as the Proposed Plan. This principally drives the lesser RSE of Alternative Plan #2 compared to the Proposed Plan. As such, it appears that Alternative Plan #2 does not provide the most value in addressing wildfire risk.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan. However, when compared to overhead lines, underground lines have several drawbacks that were not captured in the modeling and analysis. Underground systems:

- are more difficult to repair;
- cannot be visually inspected;
- require service interruptions to repair; and
- are more difficult to troubleshoot in emergencies, which can lead to longer outages.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Through the RAMP process, SCE has learned some important lessons in degrees of confidence in modeling mitigation effectiveness, constraints and limitations of the bowtie structure, and mitigations that cannot be easily modeled. Each area is discussed below.

1. Constraints of Bowtie-Structured Analysis

Use of the bowtie structure can limit our ability to assess the complete suite of risk benefits and tradeoffs associated with mitigations assessed in this chapter.

For example, the triggering event – i.e., the center of the bowtie – for wildfire analysis is an ignition associated with SCE in the high fire risk area. However, SCE's wildfire mitigation strategy focuses not only on fire prevention (i.e., reducing potential ignitions) but also suppression (i.e., more rapid identification and assessment of wildfires) and enhancing system resiliency (i.e., more robust design that can withstand damage during wildfires).

Because the triggering event in this analysis was limited to fires associated with SCE facilities, the fire prevention benefits of SCE's controls and mitigations are represented. However, the full suppression benefits and system resiliency benefits of SCE's controls and mitigations are understated, because these are benefits apply to *all fires*, not just SCE-associated fires.

Some operational measures such as PSPS [M5] have operational risks that are likewise understated due to the bowtie structure. The triggering event in the bowtie limits the analysis to fire ignition events. Implementing PSPS results in de-energizing selected circuits under Red Flag conditions, but it is virtually guaranteed that there will be more de-energized circuits then there will be ignitions avoided. The reliability "risk penalty" for de-energization (CMI for customers on these circuits) will accrue for all PSPS implementation events, but the risk analysis only evaluates the smaller number of ignition events. Therefore, the center of the bowtie itself prevents a complete analysis of all of the adverse operational risks associated with PSPS implementation.

2. Mitigation Benefits Not Captured in the Risk Analysis

SCE modeled the risk benefits of mitigations relative to the risk being evaluated in the chapter. Sometimes, a mitigation (such as M9 – Fire-Resistant Poles) can provide benefits in reducing the risk associated with ignitions associated with SCE. A mitigation like fire-resistant poles can also provide benefits in connection with fires that are not associated with SCE. In other words, the scope of this chapter necessarily focuses on fire ignitions that are associated with SCE. But a fire-resistant pole is "indifferent" to the cause of the fire. Its resistant capabilities will apply regardless of who or what caused the fire.

Additionally, the benefits of fire-resistant poles (and several other controls and mitigations in this chapter, and others) will continue beyond the six-year RAMP window.[73] Accordingly, the total benefits of these poles, as modeled in this chapter, are understated, since our analysis focuses on risk benefits over the 2018-2023 period.

B. Data Collection & Availability

To develop consequence distributions for modeling purposes, SCE utilized data reported by CalFire for statewide fires greater than 300 acres, with a cause classified by CalFire as "Electric Power." The data was collected in October 2018, and 2017 fire data was not yet available within the Redbooks that CalFire publishes. Given the significance of the 2017 fire activity, SCE reviewed news releases issued by CalFire to collect data on several additional fires from 2017 that had a cause classified by CalFire as being "caused by trees coming into contact with power lines" or being "caused by electric power and distribution lines, conductors and the failure of power poles."[74]

SCE also faced challenging data collection and availability issues regarding consequence models for fires. For example, the CalFire data was not immediately helpful for developing serious injury, fatality, and financial consequence models for smaller fires. Generally, the CalFire data provided far less information on the financial and safety consequences of smaller fires.

SCE faced a different data challenge in modeling the reliability consequences for both small and large fires. In general, SCE has a large and robust data source for outage information (ODRM). Unfortunately, while this database captures CMI outage characteristics for fire-related outages in the SCE system, it does not include details of the corresponding fire characteristics

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

[74] 2017 fires that were identified in 2018 CalFire press releases that were included within analysis include: La Porte, Lobo, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket, Atlas, Cascade, and Liberty fires. These links provide the specific detail:
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause%20v2%20AB%20(002).pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause.pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/Cascade%20Fire%20Cause%20Release.pdf
http://www.rvcfire.org/Documents/NEWS%20RELEASE%20-%20CAL%20FIRE%20INVESTIGATORS%20RELEASE%20CAUSE%20OF%202017%20LIBERTY%20FIRE.pdf

(i.e., larger or smaller, Red Flag or non-Red Flag Days, SCE- or non-SCE-associated ignition). Because ODRM is a circuit-level outage database and not a fire-related outage database, some assumptions were required to translate circuit-level outage details into fire-level outage consequence distributions for reliability.[75] As a future opportunity for improvement, directly tracking CMI consequences of fires in fire databases would be preferable to attempting to merge separate fire and outage databases.

C. Performance Metrics

The following metrics can help track performance related to wildfire risk:

1. Fire Ignitions Associated with SCE Equipment

This metric relates to ignitions occurring in SCE's service area. Specifically, SCE tracks Commission-reportable ignitions related to SCE electrical equipment or workers, that meet all of the following criteria: (1) A self-propagating fire of material other than electrical and/or communication facilities; (2) The resulting fire traveled greater than one linear meter from the ignition point; and (3) SCE has knowledge that the fire occurred at the time of filing the report. This metric represents the triggering events associated with the wildfire risk bowtie.

2. Covered Conductor Installed in HFRA

This metric tracks the number of circuit miles of covered conductor installed in SCE's HFRA. This metric is directly associated with M1, which aims to reduce the drivers that lead to ignitions. The quantity of covered conductor installed represents the extent to which SCE's overhead distribution lines in HFRA are hardened and represents a leading indicator for fire ignitions. SCE's target for this metric, at this time, is 2,426 circuit miles from 2018 through 2023.[76]

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[75] For small fires, SCE used ODRM "CMI per circuit" data from fire-related cause codes with major event days (MEDs) excluded, as the basis of a CMI consequence distribution for small fires. The two underlying assumptions in this methodology are that (a) small fires will not be enough to trigger MEDs, and (b) small fires are generally individual circuit outage events.
For large fires, SCE used ODRM "CMI per day" data from fire-related causes codes with MEDs included, as the basis of a CMI consequence distribution for large fires. The two underlying assumptions in this methodology are that (a) large fires may be enough to trigger MEDs, and (b) large fires are most likely to be events that impact multiple circuits. In general, SCE expects that this methodology will understate CMI/fire for large fires that span multiple days, but will overstate CMI/fire for large fires where multiple fires burn on the same day. For purposes of RAMP, SCE assumed that these two factors will generally offset each other and result in a reasonable reliability consequence distribution for large fires.
[76] The 2,426 circuit miles identified includes four circuit miles completed prior to the GS&RP filing (A. 18-09-002), 592 miles described in the GS&RP filing through 2020, and 1,830 miles estimated to be required

3. Branch Line Fusing in HFRA

This metric tracks the number of fusing locations addressed by M8 (Fusing Mitigation) in HFRA. This mitigation measure aims to reduce ignitions when faults occur on distribution branch lines in HFRA. Because Fusing Mitigation encompasses all branch lines for portions of circuits that traverse HFRA, it represents another measure for hardening distribution circuits in HFRA. SCE's plan, at this time, is to address 15,613 fuse locations from 2018 through 2020,[77] by installing or replacing fuses on branch lines with faster acting current-limiting type fuses.

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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.

[77] Please see discussion at Section IV regarding Fusing Mitigation (M8).

IX. Appendix 1: Long Term Analysis of M1 – Wildfire Covered Conductor Program

Long-lived assets that are installed during the 2018-2023 RAMP period continue to operate and provide risk reduction benefits for many decades afterward. To provide an illustrative example of capturing the long-term benefits of such assets, SCE piloted a limited study focusing on covered conductor. Use of covered conductor is represented as M1 (Wildfire Covered Conductor Program).

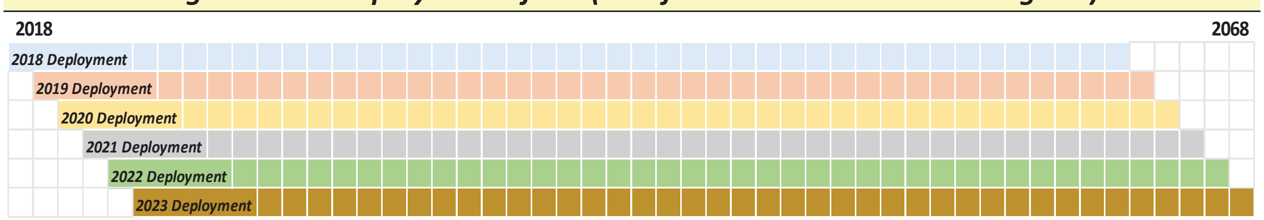
The RAMP analysis is extended out to 50 years to estimate the full benefit that the covered conductor assets provide over their useful life.

For purposes of this limited study, SCE made the following simplifying assumptions:

- 45 years of useful life for the deployments made each year during the RAMP period;
- No degradation occurring during the 45-year period;
- No benefits occurring after the 45-year period;
- No discounting of costs or benefits; and,
- M1 is run as a stand-alone portfolio with no other mitigations / controls.[78]

Figure IX-1 illustrates the full timeline when covered conductor is deployed during the RAMP period:

Figure IX-1 – Deployment of M1 (Wildfire Covered Conductor Program)

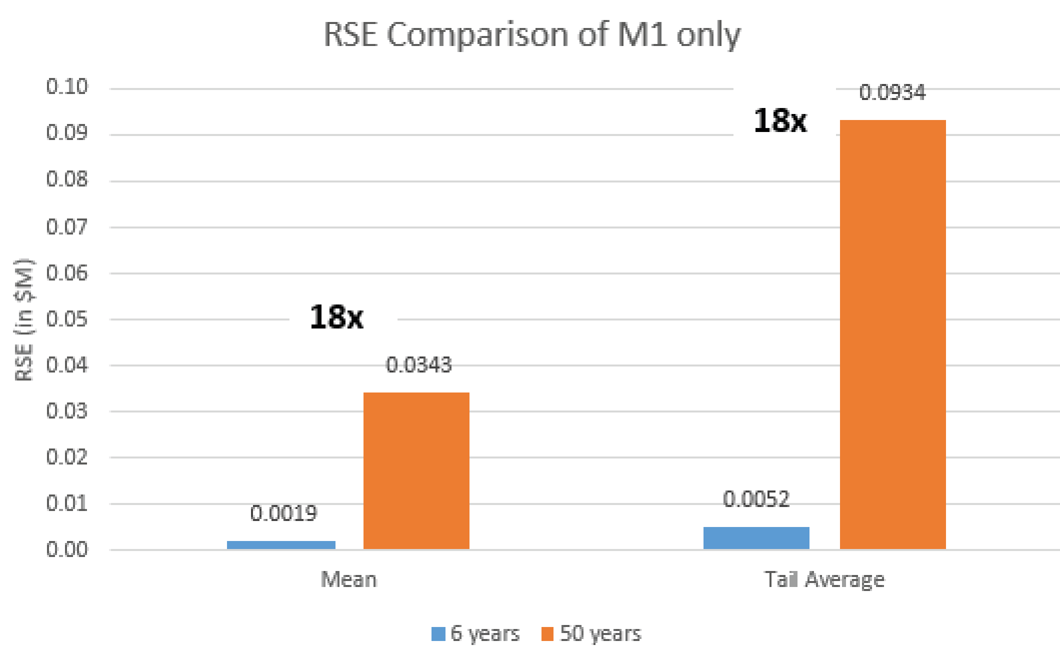


The chart below illustrates the Risk Spend Efficiency (RSE) for covered conductor (M1) for the 6-year RAMP period and the RSE for a 50-year period. The chart includes comparisons using both mean and tail average results.

[78] See Chapter 2 - RAMP Model Overview, Section 3, for discussion on scenarios with multiple mitigations.

Compared to the 6-year RAMP period analysis, the long-term RSE increases approximately 18 times on a mean basis, and increases approximately 18 times on a tail-average basis. This is shown in Figure IX-2.

Figure IX-2 – Short and Long-Term RSE Comparison of M1



For additional detail on performing long-term risk analyses, please see Chapter 8 (Hydro Asset Failure), Appendix 1. In that Appendix, SCE pilots a full long-term evaluation on the entire Hydro Asset Safety chapter, and includes more robust discussion on the impacts involved in modeling risk and mitigations beyond the RAMP period.

DATA REQUEST RESPONSE
Bear Valley Electric Service
BVES R.18-10-007

Response provided by:	Paul Marconi
Title:	Director, Bear Valley Electric Service
Data Request Number:	Data Request SEDWMP-1
Data Request Originator:	Wildfire Mitigation Plan Team (WMPSED@cpuc.ca.gov)
Date Received:	March 14, 2019
Date Due:	March 19, 2019
Date Provided:	March 19, 2019

Data Request received via email from Wildfire Mitigation Plan Team (WMPSED@cpuc.ca.gov) on March 14, 2019. This data request was sent to BVES without a title number. BVES has numbered this data request "SEDWMP-1":

Reference – Bear Valley Wildfire Mitigation Plan 4.1.1.2 Under-grounding the Ute Lines (pg 20):

1. **Provide the status of ownership of the Ute Lines.**

   Response:
   The Ute Lines (1 & 2) are Southern California Edison (SCE) assets.

2. **Has or is Bear Valley BV sought approval for the asset transfer and/or undergrounding project funding through any another CPUC proceeding?**

   Response:
   No. At the time of BVES filed its most recent General Rate Case (A.17-05-004) on May 1, 2017, this proposed project had not been developed. BVES is seeking approval for this project as part of its Wildfire Mitigation Plan filed on February 6, 2019 in accordance with R.18-10-007 and SB-901.

3. **Provide analysis wherein BV determined that undergrounding of the Ute Lines was the most appropriate option in order to mitigate catastrophic wildfire likelihood or catastrophic wildfire impact.**

   Response:
   BVES service area is completely surrounded by SCE territory. BVES loads are served by 2 main sub-transmission lines that are owned and operated by SCE. These are the Ute lines and the Radford line.

   The SCE Ute Lines (1 & 2) that begin from SCE Cottonwood substation, located in Lucerne consist of approximately 1.5 miles of overhead sub-transmission bare lines (34.5 kV) that connect the BVES system at two points with the SCE Goldhill Switch Station.

The Ute Lines 1 & 2 run on the same poles for a large section of the circuit. These SCE assets are located in the U.S. Forestry Service controlled areas and also in an environmentally sensitive area known as the "pebble plain".
The Ute lines provide approximately 72% of rated supply capacity and under normal conditions 100% of BVES' loads. The Ute Lines are completely in a HFTD Tier 2 area.

The Radford line connects with SCE Harnish line at the Radford AR. The SCE Harnish line is connected to SCE Zanza Substation located in Redlands, Riverside County. The Radford line mostly traverses a HFTD Tier 3 areas, and during the summer months SCE de-energizes its Harnish line, which in turn de-energizes BVES Radford line.

The Ute lines and the Radford line allow BVES to adopt a defensive operational scheme during the fire season by allowing the de-energization of the Radford Line. Therefore, these lines are critical to BVES' energy supply and reliability and permit BVES to significantly mitigate the risk of wildfire in its HFTD Tier 3 area.

The Holcomb Fire of June 2017 damaged several SCE facilities including taking out the Ute Lines (Ute 1 and 2). Following the Holcomb Fire, BVES entered discussions with SCE on how to improve safety and reliability of the supply from Lucerne. While the lines did not cause the Holcomb Fire, it is clear the area is susceptible to wildfire (very dry vegetation and consistently high winds – HFTD Tier 2). Therefore, BVES and SCE explored the prospect of:

- BVES constructing lines equivalent to the Ute 1 & 2 along Holcomb Valley Rd, from the SCE Goldhill Switching Station (located adjacent to the Big Bear Valley waste transfer station and landfill) to the BVES 34 kV sub-transmission system on Highway 18 (North Shore Dr.).
- SCE would then remove its Ute Line assets from the U.S. Forestry area.

This project was determined to be optimal because it:

- Removes the threat of lines causing possible wildfire in the area.
- Significantly improves reliability of the main source of supply for the BVES service area by: (1) removing the single point of failure (both lines on same poles) and (2) undergrounding the lines to make them less susceptible to overhead conductor vulnerabilities to bad weather conditions, vegetation, animals, car-hit-poles, etc.
- Moves electrical assets out of the U.S. Forestry Service and environmentally sensitive areas, thus reducing the adverse impact of inspections, maintenance and repair construction work on ecologically sensitive areas.

Reference – Bear Valley Wildfire Mitigation Plan 4.3.1 Operational Considerations and Special Work Procedures (pg 28):

4. **Given that the recent trend of the Southern California wildfire season extending through the November and December timeframe, has Bear Valley considered changes to the timeframes for its defensive operational scheme?**

Response:
The timeframes described in BVES' Wildfire Mitigation Plan for its defensive operational scheme are the normal target dates but the ultimate decision to change the operational scheme rests with the Operations & Planning Manager. The Manager also ascertains the actual weather conditions and forecasts, as well as the fuel inventory in the service area before directing any changes in the operational scheme. As additional data are collected, BVES will re-evaluate the target dates in each future annual Wildfire Mitigation Plan it files with the Commission.

5. **Under what circumstances would Bear Valley consider such changes?**

   Response:
   BVES ascertain t the degree of dryness of the service area, the amount of fuel inventory as well as the long-term forecasts (storm patterns, projected Santa Ana winds, etc.). It should be noted, that if BVES were to shift out of its defensive operational scheme, it would only take a few hours to shift back into it. In BVES' Wildfire Mitigation Plan Section 4.3.1, the following guidance is provided:

   *"**Execution:** As stated previously, BVES monitors the NFDRS fire danger forecast each day and then determines the proper operational focus from reliability to fire prevention. Exact steps depend on the level of fire threat. As indicated in Table 4 4 below, "Brown", "Red", and "Orange" are considered elevated fire threat conditions that require the BVES system to be configured for fire prevention over reliability concerns."*

   If BVES were to shift out of its optimized defensive operational scheme and conditions favorable to wildfire were to suddenly develop, BVES would shift to its defensive operational scheme prioritizing fire prevention over reliability.

Reference – Bear Valley Wildfire Mitigation Plan Evaluation of Higher Fire Threat Areas (pg 16)

6. **Provide an outline of the specific mitigations that will be deployed in five (5) high risk localities identified by Bear Valley or describe how those localities will be prioritized during the rollout of their general mitigation activities.**

   Response:
   The five high risk localities are targeted to be the "first-in-line" for all of the BVES Wildfire Mitigation measures including: elimination of conventional fuses, covered wire projects, pole loading and assessment program, tree attachment removal project, inspections, vegetation management efforts, etc. It is BVES' goal to eventually not have any "high risk localities".

Wildfire Mitigation Plan

Jeff Matthews

February 13, 2019

Liberty Utilities

Liberty CalPeco Service Territory

Serves approximately 49,000 electric customers in California in and around the Lake Tahoe Basin.

Its service territory is geographically compact and generally encompasses the western portions of the Lake Tahoe Basin.

Customers are located in portions of these counties:

- Placer
- El Dorado
- Nevada
- Sierra
- Plumas
- Mono
- Alpine

Almost 80% of customers are located in the Lake Tahoe Basin. The biggest population center is the City of South Lake Tahoe. The Liberty CalPeco service territory extends from Portola in the north to Markleeville and Topaz Lake in the south.

Risk Drivers

Wildfire Risk Assessments in Liberty CalPeco Service Territory

Agency and / or Rating Name	Scope of Fire Risk Rating	Risk Rating
CPUC, Fire-Threat Map Adopted January 19, 2018	Areas or zones where enhanced fire safety regulations in D. 17-12-024 will apply	HFTD; Mostly Tier 2 (elevated risk) with some Tier 3 (extreme risk) areas.
USDA Forest Service, NFDRS	County-level assessment of fire danger for that day or the next day based on fuels, weather, topography, and risks	Identifies the number of days of High to Very High Fire Danger Levels
CAL FIRE, California Fire Hazard Severity Zone Map Update Project	City and County-level assessments of fire "hazard" zones	Moderate, High, and Very High Fire Hazard Severity Zones
SFIDC, Sierra Front Wildfire Cooperators	Interagency monitors and mobilizes local resources against identified fire threat within the Sierra Front area	Risk boundary covers eastern region service area, which lies in Tier 2 and Tier 3 HFTD

Strategy & Program Overview

Existing and proposed wildfire preventative strategies can be categorized into five main mechanisms that align with utility best practices. Together, the five components create a comprehensive wildfire preparedness and response plan with a principal focus on stringent construction standards, fire prevention through system design, proactive operations and maintenance programs, and well-socialized operating procedures and staff training.

- **Design & Construction:** These strategies consist of system, equipment, and structure design and technical upgrades.
- **Inspection & Maintenance:** These strategies consist of assessment and diagnostic activities as well as associated corrective actions.
- **Operational Practices:** These strategies consist of proactive, day-to-day actions taken to mitigate wildfire risks.
- **Situational & Conditional Awareness:** These strategies consist of methods to improve system visualization and awareness of environmental conditions.
- **Response & Recovery:** These strategies consist of procedures to react to de-energization, wildfire, or other related emergencies.

Wildfire Prevention Strategy and Programs

Mitigation Area	Mitigation Tool / Program	Rationale
Operational Practices	Infrastructure Protection Teams	Ensure staff is prepared to mobilize in high-risk and emergency situations
	Emergency Preparedness and Response Protocols	Ensure protocols are up-to-date with the latest mandates and best practices
	Fire Mode, Automation, Reclosers & Fast Curve Settings	Mitigate downed wires and reduce energy at potential fault locations
	SCADA	Promotes faster response to outage notifications
Inspection Plans	Proactive Patrols	Reduce risk by conducting regular system inspections to identify at risk areas
	Equipment Inspections	Regular patrols that identify aging infrastructure or equipment that pose a fire risk
	Geographic Information System (GIS)	Leverage tool to account for equipment inventory and provide available data to the Commission and CAL FIRE when necessary
	Tree Attachment Inventory Inspection	Mitigate contact of ignition (heat) fuel sources by increasing distance between sources

Liberty Utilities

Wildfire Prevention Strategy and Programs

Mitigation Area	Mitigation Tool / Program	Rationale
System Hardening Upgrades	Fusing	Mitigate downed wires and reduce energy at potential fault locations
	Covered Conductor Program	Mitigate contact of ignition source (heat) by covering the wire.
	Pole Loading	Determine if structural integrity of the pole is within calculated threshold
	Undergrounding Distribution Lines	Significantly reduces fire risk while maintaining aesthetic quality of the surrounding environment
	Substation Facility Replacement/Enhancement	Modernize aging capital infrastructure to mitigate fire risk
Vegetation Management	Vegetation Management Program	Mitigate wildfire risk conditions by removing fuel source and patrolling lines
	Regular and Off-Cycle Inspections	Readily deploy staff/contractors when notified of leaning or fallen vegetation or when encountered on routine patrols.
Situational Awareness Protocols	Weather Stations	Improves forecasting and de-energization and restoration plans
	Weather Monitoring	Forecasts potential hazards; promotes quick response time
Public Safety Power Shut-Off Protocols (PSPS)	Public Safety Power Protocols	Mitigates wildfire risk conditions by shutting off the power and removing potential ignition (heat) source

Liberty Utilities

Emergency Preparedness and Response Components

Emergency Activation

- Level of response and communication activation based on the impact of the event

Coordination

- Effective coordination and information sharing between appropriate state and local governments during an event

Mutual Assistance

- Labor and equipment resources agreement with NV Energy
- California Utilities Emergency Association (CUEA) and Western Energy Institute Mutual Assistance Roster (WEIMAR) membership

Supplemental & Contingency Planning

- Hazard specific plans or manuals referenced in the Emergency Management Plan

Additional Plan Elements

- Framework for identifying communications, safety, damage assessment, restoration, and mutual aid solutions unique to event

Training

- Roles and responsibilities in support of the Incident Command System at the Company level or the Incident Commander at the regional level

Record Keeping

- Documentation of training, program elements, comprehensive emergency plans, exercises, debriefing, corrective action and evaluations for due diligence, training, and regulatory compliance

Liberty Utilities

Performance Metrics and Monitoring

	Metric	Rationale	Risk Reduction Assumption
Fire Incidents	Number of utility-caused fires	Determination of Plan's overall effectiveness	Fire frequency will reduce by maintaining a hardened system and commitment to these operational practices
Infrastructure	Number of Wildfire Risk Events (e.g. number of bare line contact with vegetation)	Assess if plan has reduced risk events	Accounting for incidents will, overtime, show risk reduction in fire ignition
	Number of Fuse Replaced Annually	Determine if plan is on schedule	An increase in the number of current limiting fuses will mitigation wildfires
	Length of Bare Wire Covered Annually	Determine if plan is on schedule	An increase in the number of miles of covered conductors will mitigation wildfires
	Number of Recloser Replacements or Upgraded Annually	Determine if plan is on schedule	Reclosers with sensitive setting and high-speed clearing will mitigate wildfires
	Substation Replacement and Upgrade -Narrative on project progress	Assess reliability and safety improvements	Elimination of wooden box structures and oil circuit breakers will mitigate risk
	Weather Station Installation	Determine if deployment plan is on schedule	An increase in the number of weather stations will mitigation wildfires
Operations	Average Time for Clearance Permissions from Local Agencies	Assess mitigation plan constraints and timelines	A reduction in the amount of time to clear vegetation will reduce risk
	Vegetation Management Investment and inspections	Assess value after increasing budget in inspection procedures; clearances	Determine if an increase or decrease in vegetation follow-up results from increase budget.
Customer Service	Number of Customer Service Calls about identified and confirmed at-risk Vegetation	Assess if plan has reduced customer concerns and risk events	Track vegetation service calls on customer responsibility and Liberty vegetation.
PSPS Narrative	Number of PSPS Events	Monitor the number of PSPS events over time as an indicator of changing climatic and weather patterns	Determine the effective of procedures for PSPS events.

ALJ/RWH/jt2 **Date of Issuance 1/16/2019**

Decision 19-01-019 January 10, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Its Grid Safety and Resiliency Program.	Application 18-09-002

DECISION APPROVING AN EFFECTIVE DATE FOR AN INTERIM MEMORANDUM ACCOUNT

Summary

This Decision authorizes Southern California Edison Company to establish the Grid Safety and Resiliency Program Memorandum Account effective September 10, 2018 as requested in a Motion filed on September 10, 2018 and in Application 18-09-002. The Decision also establishes reporting requirements to monitor the costs booked to the Grid Safety and Resiliency Program Memorandum Account over the course of this proceeding. This Decision does not allow SCE to recover costs recorded in the Grid Safety and Resiliency Program Memorandum Account. Whether, how, and to what extent SCE may recover the costs tracked in the Grid Safety and Resiliency Program Memorandum Account will be determined after the application has been fully reviewed by the Commission and determined in a subsequent decision.

Discussion

Southern California Edison's Request for the Memorandum Account

On September 10, 2018, Southern California Edison Company (SCE) filed a Motion requesting an expedited order adopting the interim Grid Safety and Resiliency Program Memorandum Account (GSRPMA) proposed in SCE's concurrently filed Application 18-09-002 (Application) effective as of the date of its filing, September 10, 2018.

SCE seeks Commission approval to make the GSRPMA effective as of the filing date of the Application so that SCE may begin tracking Grid Safety and Resiliency Program (GSRP) costs expeditiously while the Commission resolves the concurrent Application and associated request for a two-way balancing account. As SCE notes, granting SCE's request for this memorandum account would not prejudge whether, how, and to what extent SCE may recover the costs tracked in the GSRPMA. Rather, it simply preserves SCE's ability to request further Commission consideration of the recoverability of such costs, without objection that might otherwise be asserted based on the retroactive ratemaking doctrine. Granting a memo account does not guarantee recovery of any costs booked into the memo account, because they will be reviewed at a later date.

SCE asserts that good cause exists to approve the interim GSRPMA as SCE is taking prompt action to address increasing wildfire risk in furtherance of state policy and is already incurring incremental costs.

SCE claims approval of the GSRPMA is appropriate in light of recent legislation that explicitly provides for utilities to establish memorandum accounts to track incremental wildfire mitigation costs not currently authorized in rates or, in SCE's case, requested in a general rate case (GRC).[1] Because of the serious nature of the wildfire issue, SCE filed this application expeditiously, not waiting for proposed legislation (SB 901) to become law and be implemented by the Commission. Instead, SCE filed its Application on September 10, 2018, prior to SB 901 being signed into law and requested an interim account to track its ongoing GSRP costs during the pendency of this proceeding.

SCE also claims the Commission has a longstanding practice of establishing memorandum accounts to avoid retroactive ratemaking, and that allowing the interim GSRPMA would be consistent with that practice.[2]

Agreement Resolving Opposition of Intervening Parties

The Public Advocates Office at the California Public Utilities Commission (Public Advocates) filed a Response opposing SCE's Motion on September 25, 2018. Public Advocates stated the issue does not need to be addressed before a determination is made by the Commission on the full application, and

[1] Specifically, Senate Bill (SB) 901 provides that utilities be able to establish "a memorandum account to track costs incurred for fire risk mitigation that are not otherwise covered in the electrical corporation's revenue requirements." Stats. 2018, Ch. 626, *codified* at Pub. Util. Code § 8386(j). SCE also cited Assembly Bill (AB) 2346 to support its motion (AB 2346 would have enabled utilities, upon request to the Commission, to be able to record incremental grid hardening, vegetation management, and other wildfire mitigation costs in the Wildfire Expense Memorandum Account). AB 2346 was vetoed by Governor Brown.

[2] SCE Motion at 5-7, *citing,* Decision (D.) 03-05-076 at 6; Resolution E-3761 at 3 (Nov. 29, 2001); D.16-03-009, Decision Granting Pacific Gas and Electric Company's Request for a January 1, 2017 Final Decision Effective Date; D.14-06-012, Decision Granting January 1, 2015 Effective Date for Pacific Gas and Electric Company's Test Year 2015 Revenue Requirement at 3-5; D.18-06-029, Alternate Decision Authorizing Establishment of the Wildfire Expense Memorandum Account at 15.

recommended the Commission deny SCE's motion, and/or hold the motion in abeyance until the decision on the merits of the application.

Public Advocates argued that the request in the motion is duplicated in the Application itself, and thus there is no need to rule on the motion before the application is decided. Public Advocates also claims that granting the motion would be inconsistent with the Commission's policy requiring that memorandum accounts be established on a prospective basis only.[3] Public Advocates claims that the cases cited by SCE to support its motion represent narrow exceptions to the general rule against retroactive ratemaking and deal with a previously defined set of costs, or establish memorandum accounts on a prospective basis.

On October 5, 2018, SCE submitted a Reply to the Response of the Public Advocates Office. SCE argues that it would not be premature to approve the memorandum account before the final decision on the merits of the application. SCE claims it is already incurring costs and waiting to approve the memorandum account could result in those costs being disallowed on a retroactive ratemaking basis. Approving the memorandum account now would remove that claim and ensure that any costs the Commission does ultimately approve would be tracked and available for recovery from ratepayers. SCE also argues that while the Commission usually makes memorandum accounts effective prospectively, the Commission has authority to make exceptions to that general policy under appropriate circumstances. SCE claims that the current proposal falls within such an exception, an urgent situations in which the

[3] Response of the Public Advocates Office at 3, *citing*, D.03-05-076 at n. 5, and D.99-11-057.

applicant utility expects to incur substantial incremental costs prior to a final Commission decision on the merits. SCE states that in such situations, the Commission has granted memorandum account relief for the purposes of tracking ongoing costs. SCE also acknowledges that granting interim relief and creating this account does not prejudge the appropriateness of any recovery of costs so recorded in the GSRPMA.

The Utility Reform Network (TURN) also expressed reservations about approving the GSRPMA until SCE clarifies whether there is any overlap with the treatment of the memorandum account that would be implemented as part of Rulemaking 18-10-007.[4]

At the Prehearing Conference on November 15, 2018, SCE, Public Advocates and TURN announced that they had reached an agreement on two issues on which they had differing views with respect to the next steps in this proceeding, specifically approval of SCE's motion seeking a September 10, 2018, effective date for the GSRPMA, and the overall schedule of the proceeding. Public Advocates and TURN both agreed to withdraw their objections to implementation of SCE's GSRPMA and SCE in turn agreed to support the schedule for the proceeding put forth by Public Advocates and TURN.

This agreement removes opposition to SCE's Motion and allows the Commission to consider it on an unopposed basis.[5] The agreement also

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[4] Joint Prehearing Conference Statement dated November 13, 2018, at 8. (Rulemaking 18-10-007 was adopted on October 25, 2018 to implement the provisions of Senate Bill 901 related to electric utility wildfire mitigation plans.)

[5] *See,* RT at 31 (the Small Business Utility Advocates stated it does not oppose creation of the memorandum account, and no party raised any new objection at the PHC).

establishes a schedule for the proceeding that will be memorialized in the forthcoming Scoping Memo that will result in intervenor testimony being served in April 2019.

Approval of the Memorandum Account

Approval of the GSRPMA, effective September 10, 2018, the date this application was filed, is in the public interest. SCE is proposing to undertake significant and incremental steps to improve its systems and infrastructure to mitigate wildfire risks. While there are important questions to ask about the actions SCE is undertaking, SCE is taking these actions without any guarantee the Commission will approve recovery of the costs from ratepayers. We agree that the subject of SCE's application is an urgent situation where SCE expects to incur substantial incremental costs prior to a final Commission decision on the merits of the Application. Thus, while SCE is incurring these costs, it is not only appropriate, but also in the public interest that it keeps track of these costs.

Public Advocates is correct that we do not need to approve the memorandum account before we reach a final decision on the merits of the application. However, we agree with SCE that allowing it to record the costs it is incurring related to this application in a memorandum account will avoid retroactive ratemaking objections should those costs ultimately be approved. In addition, establishing a memorandum account effective at the initiation of this application provides the Commission an opportunity to establish reporting and financial controls at the onset of this proceeding.

Wildfire risk has been a problem for many years and the requests made in this proceeding would typically be included in a GRC. SCE's 2018 Test Year GRC application, Application (A.) 16-09-001 has not yet concluded, and since the application's filing in 2016, wildfire mitigation issues have become more urgent and been identified as a high priority for utility and Commission attention. As its GRC has not been decided, SCE is in a unique position with respect to the wildfire mitigation measures proposed in this application. Such a situation is not likely to be replicated in the future for SCE or other utilities. A GRC is the preferred venue where these types of investments should be brought forward in the future.

Establishing the memorandum account does not provide an approval of the proposed costs. The ultimate resolution of the reasonableness of the proposed costs will be determined after the application has been fully reviewed by the Commission and includes allowing intervening parties the opportunity to litigate the merits of the application. Given the unique nature of this application we will closely scrutinize the proposed costs to ensure the proposed costs are truly incremental, and not recovered in another way such as in a GRC. For example, if SCE had forecast certain wildfire mitigation costs in a GRC, resulting in those costs being included in rates, they would not be incremental, and SCE could not record those same costs in the GSRPMA and subsequently seek rate recovery. Incrementality is a complicated, fact-specific issue that will be examined during the course of this proceeding to ensure costs currently authorized in rates or requested in A.16-09-001 are not also recovered as a result of this proceeding. SCE bears the burden of proof in this proceeding to show that the costs proposed are incremental and that appropriate adjustments are made where the proposed actions will reduce the usefulness of existing plant in operation. Once a decision on the activities and costs proposed in SCE's GSRP application is issued, costs recordedin the GSRPMA must be reviewed to determine whether the costs of activities recorded in the interim account adopted here are reasonable and consistent with the terms of the Commission's ultimate decision.

Reporting and Other Transparency Measures

While we have approved memorandum accounts with effective dates prior to the final decision on the merits of the proposed costs, typically, we have done so for relatively routine and ongoing matters. SCE is asking for the memorandum account to be effective on the date the application was filed so that it can begin tracking costs as of that date. In approving SCE's request, we expect to achieve a level of transparency in SCE's implementation of its proposed GSRP. Accordingly, SCE will be required to serve monthly reports providing a full and complete accounting of its activities. These reports will include all expenditures for capital costs as of the date for the monthly report and any additional information reasonably required by Commission staff. SCE shall work with the Commission's Energy Division staff to develop the format and content of these monthly reports.

SCE forecasts that nearly two-thirds of the forecast revenue requirement and sixty percent of the capital expenditures will occur in 2020. We expect to conclude our review of this application in 2019. For 2018 and 2019 SCE forecasts more than $77 million in added revenue requirement and more than $166 million in capital expenses. Thus, in addition to the monthly report of what has been spent, in order to ensure the projected expenditures occur when planned, we will require SCE to serve, 30 days in advance of its planned expenditures for each quarter of its projected 2018 and 2019 forecast costs. Therefore, a report will be served for each $19,460 million in revenue requirement, and for each $41,627 million in capital expenditures. As we have noted, the timing and nature of this application is unique, and while we agree with SCE that it should be allowed to begin tracking its costs related to the activities in the application, we will require SCE to be transparent throughout this process. These reporting requirements will provide the Commission a systemic tool to help monitor the costs being recorded in the GSRPMA.

Waiver of Comment Period

As explained above, Public Advocates and TURN both agreed to withdraw their objections to SCE's Motion to Approve the Grid Safety and Resiliency Memorandum Account. SCE's request is unopposed.

Under Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the Commission may reduce or waive the period for public review and comment in an uncontested matter where the decision grants the relief requested. We waive the period for public review and comment pursuant to this rule.

Assignment of Proceeding

Michael Picker is the assigned Commissioner and Robert W. Haga is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. SCE has proposed incurring costs related to additional wildfire mitigation measures above and beyond costs requested and pending in its current test year 2018 GRC.

2. Granting a memo account does not guarantee recovery of any costs booked into the memo account, because they will be reviewed at a later date.

3. The subject of SCE's application is an urgent situation where SCE expects to incur substantial incremental costs prior to a final Commission decision on the merits.

4. Approval of an interim GSRPMA preserves SCE's ability to request further Commission consideration of the recoverability of such costs.

5. Approval of an interim GSRPMA, effective September 10, 2018, the date this application was filed, is in the public interest.

6. SCE's tariff language should clearly indicate that only incremental costs may be recorded in the GSRPMA.

7. SCE forecasts that nearly two-thirds of the forecast revenue requirement and sixty percent of the capital expenditures will occur in 2020.

Conclusions of Law

1. SCE's request for an interim GSRPMA should be approved.

2. Establishing the memorandum account does not provide an approval of the proposed costs.

3. The Commission may make the GSRPMA effective as of the date of SCE's application.

4. Only incremental costs above and beyond costs authorized in SCE's test year 2018 GRC should be recorded in GSRPMA.

5. Approving the GSRPMA preserves the ability of SCE to request further Commission consideration of the recoverability of such costs, without objection that might otherwise be asserted based on the retroactive ratemaking doctrine.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is authorized to establish an interim Grid Safety and Resiliency Program Memorandum Account, effective September 10, 2018.

2. Southern California Edison Company is directed to file its tariff implementing the interim Grid Safety and Resiliency Program Memorandum Account via Tier 2 Advice Letter no later than 30 days from the date of this decision. The Advice Letter shall also include a proposal for the format to be used in monthly reporting.

3. The Grid Safety and Resiliency Program Memorandum Account tariff language must specify that only incremental costs above and beyond those authorized in SCE's test year 2018 General Rate Case may be recorded in the account.

4. Southern California Edison Company's Grid Safety and Resiliency Program Memorandum Account tariff language should be consistent with this decision.

5. Southern California Edison Company shall serve monthly reports providing a full and complete accounting of amounts recorded in the Grid Safety and Resiliency Program Memorandum Account.

6. Southern California Edison Company shall include in its monthly reports the amounts expended pursuant to the activities included in the Grid Safety and Resiliency Application, including all expenditures for capital costs as of the date of the monthly report, any other information that Commission Energy Division staff reasonably requires, and any other further information reasonably necessary for a full and complete reporting to the Commission.

7. Southern California Edison Company shall consult with Commission Energy Division staff at least one week prior to the submission of each monthly report to determine if any changes are required to the format submitted with the Advice Letter implementing the interim Grid Safety and Resiliency Program Memorandum Account.

8. Southern California Edison Company shall serve a notice 30 days in advance of when it projects it will have spent each quarter of its projected 2018 and 2019 forecast costs (combined). A separate notice shall be served for each $19,460 million in revenue requirement, and $41,627 million in capital expenditures.

9. The specific criteria for rate recovery of costs recorded in the Grid Safety and Resiliency Program Memorandum Account will be addressed through the prosecution of this proceeding.

This order is effective today.

Dated January 10, 2019, at San Francisco, California.

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners